Nos. 20-1530, 20-1531, 20-1778, 20-1780

IN THE

Supreme Court of the United States

WEST VIRGINIA, ET AL.,

v.

ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

THE NORTH AMERICAN COAL CORPORATION,

v.

ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

WESTMORELAND MINING HOLDINGS LLC,

v.

ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

NORTH DAKOTA,

v.

ENVIRONMENTAL PROTECTION AGENCY, ET AL.,

On Writ Of Certiorari
To The United States Court Of Appeals
For The District Of Columbia Circuit

JOINT APPENDIX (VOLUME II OF IV)
(Pages 273–866)

ELIZABETH B. PRELOGAR
Solicitor General
Counsel of Record
U.S. DEPARTMENT OF JUSTICE
950 Pennsylvania Avenue, NW
Washington, DC 20530
(202) 514-2217
supremectbriefs@usdoj.gov
Counsel for Federal Respondents

LINDSAY S. SEE
Solicitor General
Counsel of Record
OFFICE OF THE W.V. ATT'Y GEN.
State Capitol Complex
Building 1, Room E-26
Charleston, WV 25305
(304) 558-2021
lindsay.s.see@wvago.gov
Counsel for Petitioners West Virginia, et al.

(additional counsel listed on inside cover)

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BETH S. BRINKMANN
Counsel of Record
COVINGTON & BURLING LLP
850 Tenth Street, NW
Washington, DC 20001
(202) 662-5312
bbrinkmann@cov.com

Counsel for Power Company Respondents

SEAN H. DONAHUE
Counsel of Record
DONAHUE, GOLDBERG & LITTLETON
1008 Pennsylvania Ave., SE
Washington, DC 20003
(202) 277-7085
sean@donahuegoldberg.com

Counsel for Non-Governmental Organization & Trade Association Respondents

BARBARA D. UNDERWOOD
Solicitor General
Counsel of Record
OFFICE OF THE ATT'Y GEN.
28 Liberty Street
New York, NY 10005
(212) 416-8016
barbara.underwood@ag.ny.gov

Counsel for Respondents New York, States and Municipalities

YAAKOV M. ROTH
Counsel of Record
JONES DAY
51 Louisiana Ave., NW
Washington, DC 20001
(202) 879-3939
yroth@jonesday.com

Counsel for Petitioner North American Coal Corporation

ANDREW M. GROSSMAN
Counsel of Record
BAKER & HOSTETLER LLP
1050 Connecticut Ave., NW
Washington, DC 20036
(202) 861-1697
agrossman@bakerlaw.com

Counsel for Petitioner Westmoreland Mining Holdings LLC

PAUL M. SEBY
Special Assistant Attorney General
Counsel of Record
GREENBERG TRAURIG, LLP
1144 15th Street, Suite 3300
Denver, CO 80202
(303) 572-6500
sebyp@gtlaw.com

Counsel for Petitioner State of North Dakota

(additional counsel listed on next page)

(continued from inside cover)

ELBERT LIN
Counsel of Record
HUNTON ANDREWS KURTH LLP
951 E. Byrd Street, E. Tower
Richmond, VA 23219
(804) 788-7202
elin@huntonak.com

Counsel for Respondent America's Power

EMILY C. SCHILLING
Counsel of Record
HOLLAND & HART LLP
901 K Street NW, Suite 850
Washington, DC 20001
(202) 393-6500
ecschilling@hollandhart.com

Counsel for Respondent Basin Electric Power Cooperative

MISHA TSEYTLIN
Counsel of Record
TROUTMAN PEPPER HAMILTON SANDERS LLP
227 W. Monroe St., Suite 3900
Chicago, IL 60606
(608) 999-1240
misha.tseytlin@troutman.com

Counsel for Respondent National Mining Association

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40 CFR Part 60

[EPA-HQ-OAR-2013-0602; FRL-9930-65-OAR]

RIN 2060-AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA is establishing: Carbon dioxide (CO_2) emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines; state-specific CO_2 goals reflecting the CO_2 emission performance rates; and guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the CO_2 emission performance rates, which may be accomplished by meeting the state goals. This final rule will continue progress already underway in the U.S. to reduce CO_2 emissions from the utility power sector.

DATES: This final rule is effective on December 22, 2015.

ADDRESSES: *Docket*. The EPA has established a docket for this action under Docket No. EPA-HQ-OAR-2013-0602. 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.*, confidential business information (CBI) or other information for which disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, 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 federal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www2.epa.gov/dockets*.

World Wide Web. In addition to being available in the docket, an electronic copy of this final rule will be available on the World Wide Web (WWW). Following signature, a copy of this final rule will be posted at the following address: *http://www.epa.gov/cleanpowerplan/*. A number of documents relevant to this rulemaking, including technical support documents (TSDs), a legal memorandum, and the regulatory impact analysis (RIA), are also available at *http://www.epa.gov/cleanpowerplan/*. These and other related documents are also available for inspection and copying in the EPA docket for this rulemaking.

FOR FURTHER INFORMATION CONTACT: Ms. Amy Vasu, Sector Policies and Programs Division (D205-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-0107, facsimile number (919) 541-4991; email address: *vasu.amy@epa.gov* or Mr. Colin Boswell, Measurements Policy Group (D243-05), Sector Policies and Programs Division, U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-2034, facsimile number (919) 541-4991; email address: *boswell.colin@epa.gov*.

SUPPLEMENTARY INFORMATION:

Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

ACEEE American Council for an Energy-Efficient Economy

AEO Annual Energy Outlook

AFL-CIO American Federation of Labor and Congress of Industrial Organizations

ASTM American Society for Testing and Materials

BSER Best System of Emission Reduction

Btu/kWh British Thermal Units per Kilowatt-hour

CAA Clean Air Act

CBI Confidential Business Information

CCS Carbon Capture and Storage (or Sequestration)

CEIP Clean Energy Incentive Program

CEMS Continuous Emissions Monitoring System

CHP Combined Heat and Power

CO_2 Carbon Dioxide

DOE U.S. Department of Energy

ECMPS Emission Collection and Monitoring Plan System

EE Energy Efficiency

EERS Energy Efficiency Resource Standard

EGU Electric Generating Unit

EIA Energy Information Administration

EM&V Evaluation, Measurement and Verification

EO Executive Order

EPA Environmental Protection Agency

FERC Federal Energy Regulatory Commission

ERC Emission Rate Credit

FR Federal Register

GHG Greenhouse Gas

GW Gigawatt

HAP Hazardous Air Pollutant

HRSG Heat Recovery Steam Generator

IGCC Integrated Gasification Combined Cycle

IPCC Intergovernmental Panel on Climate Change

IPM Integrated Planning Model

IRP Integrated Resource Plan

ISO Independent System Operator

kW Kilowatt

kWh Kilowatt-hour

lb CO_2/MWh Pounds of CO_2 per Megawatt-hour

LBNL Lawrence Berkeley National Laboratory

MMBtu Million British Thermal Units

MW Megawatt

MWh Megawatt-hour

NAAQS National Ambient Air Quality Standards

NAICS North American Industry Classification System

NAS National Academy of Sciences

NGCC Natural Gas Combined Cycle

NO_X Nitrogen Oxides

NRC National Research Council

NSPS New Source Performance Standard

NSR New Source Review

NTTAA National Technology Transfer and Advancement Act

OMB Office of Management and Budget

PM Particulate Matter

$PM_{2.5}$ Fine Particulate Matter

PRA Paperwork Reduction Act

PUC Public Utilities Commission

RE Renewable Energy

REC Renewable Energy Credit

RES Renewable Energy Standard

RFA Regulatory Flexibility Act

RGGI Regional Greenhouse Gas Initiative

RIA Regulatory Impact Analysis

RPS Renewable Portfolio Standard

RTO Regional Transmission Organization

SBA Small Business Administration

SCC Social Cost of Carbon

SIP State Implementation Plan

SO_2 Sulfur Dioxide

Tg Teragram (one trillion (10^{12}) grams)

TSD Technical Support Document

TTN Technology Transfer Network

UMRA Unfunded Mandates Reform Act of 1995

UNFCCC United Nations Framework Convention on Climate Change

USGCRP U.S. Global Change Research Program

VCS Voluntary Consensus Standard

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Executive Summary

1. Introduction

This final rule is a significant step forward in reducing greenhouse gas (GHG) emissions in the U.S. In this action, the EPA is establishing for the first time GHG emission guidelines for existing power plants. These final emission guidelines, which rely in large part on already clearly emerging growth in clean energy innovation, development and deployment, will lead to significant carbon dioxide (CO_2) emission reductions from the utility power sector that will help protect human health and the environment from the impacts of climate change. This rule establishes, at the same time, the foundation for longer term GHG emission reduction strategies necessary to address climate change and, in so doing, confirms the international leadership of the U.S. in the global effort to address climate change. In this final rule, we have taken care to ensure that achievement of the required emission reductions will not compromise the reliability of our electric system, or the affordability of electricity for consumers. This final rule is the result of unprecedented outreach and engagement with states, tribes, utilities, and other stakeholders, with stakeholders providing more than 4.3 million comments on the proposed rule. In this final rule, we have addressed the comments and concerns of states and other stakeholders while staying consistent with the law. As a result, we have followed through on our commitment to issue a plan that is fair, flexible and relies on the accelerating transition to cleaner power generation that is already well underway in the utility power sector.

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is establishing CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs)—the Clean Power Plan. These final guidelines, when fully implemented, will achieve significant reductions in CO_2 emissions by 2030, while offering states and utilities substantial flexibility and latitude in achieving these reductions. In this final rule, the EPA is establishing a CO_2 emission performance rate for each of two subcategories of fossil fuel-fired EGUs—fossil fuel-fired electric steam generating units and stationary combustion turbines—that expresses the "best system of emissions reduction . . . adequately demonstrated" (BSER) for CO_2 from the power sector.[1]

[1] Under CAA section 111(d), pursuant to 40 CFR 60.22(b)(5), states must establish, in their state plans, emission standards that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been

The EPA is also establishing 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. The guidelines also provide for the development, submittal and implementation of state plans that implement the BSER—again, expressed as CO_2 emission performance rates—either directly by means of source-specific emission standards or other requirements, or through measures that achieve equivalent CO_2 reductions from the same group of EGUs.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states 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.[2] Because Vermont and the District of Columbia

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adequately demonstrated (*i.e.*, the BSER). Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the emission standard or standards that reflect that amount of emission reduction.

[2] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility

do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas, and those areas will not be required to submit state plans on the schedule required by this final action.

The emission standards in a state's plan may incorporate the subcategory-specific CO_2 emission performance rates set by the EPA 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. State plans must also: (1) Ensure that the period for emission reductions from the affected EGUs begin no later than 2022, (2) show how goals for the interim and final periods will be met, (3) ensure that, during the period from 2022 to 2029, affected EGUs in the state collectively meet the equivalent of the interim subcategory-specific CO_2 emission performance rates, and (4) provide for periodic state-level demonstrations prior to and during the 2022–2029 period that will ensure required CO_2 emission reductions are being accomplished and no increases in emissions relative to

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to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

each state's planned emission reduction trajectory are occurring. A Clean Energy Incentive Program (CEIP) will provide opportunities for investments in renewable energy (RE) and demand-side energy efficiency (EE) that deliver results in 2020 and/or 2021. The plans must be submitted to the EPA in 2016, though an extension to 2018 is available to allow for the completion of stakeholder and administrative processes.

The EPA is promulgating: (1) Subcategory-specific CO_2 emission performance rates, (2) state rate-based goals, and (3) state mass-based CO_2 goals that represent the equivalent of each state's rate-based goal. This will facilitate states' choices in developing their plans, particularly for those seeking to adopt mass-based allowance trading programs or other statewide policy measures as well as, or instead of, source-specific requirements. The EPA received significant comment to the effect that mass-based allowance trading was not only highly familiar to states and EGUs, but that it could be more readily applied than rate-based trading for achieving emission reductions in ways that optimize affordability and electric system reliability.

In this summary, we discuss the purpose of this rule, the major provisions of the final rule, the context for the rulemaking, key changes from the proposal, the estimated CO_2 emission reductions, and the costs and benefits expected to result from full implementation of this final action. Greater detail is provided in the body of this preamble, the RIA, the response to comments (RTC) documents, and various TSDs and memoranda addressing specific topics.

2. Purpose of This Rule

The purpose of this rule is to protect human health and the environment by reducing CO_2 emissions from fossil fuel-fired power plants in the U.S. These plants are by far the largest domestic stationary source of emissions of CO_2, the most prevalent of the group of air pollutant GHGs that the EPA has determined endangers public health and welfare through its contribution to climate change. This rule establishes for the first time emission guidelines for existing power plants. These guidelines will lead to significant reductions in CO_2 emissions, result in cleaner generation from the existing power plant fleet, and support continued investments by the industry in cleaner power generation to ensure reliable, affordable electricity now and into the future.

Concurrent with this action, the EPA is also issuing a final rule that establishes CO_2 emission standards of performance for new, modified, and reconstructed power plants. Together, these rules will reduce CO_2 emissions by a substantial amount while ensuring that the utility power sector in the U.S. can continue to supply reliable and affordable electricity to all Americans using a diverse fuel supply. As with past EPA rules addressing air pollution from the utility power sector, these guidelines have been designed with a clear recognition of the unique features of this sector. Specifically, the agency recognizes that utilities provide an essential public service and are regulated and managed in ways unlike any other industrial activity. In providing assurances that the emission reductions required by this rule can be achieved without compromising continued reliable, affordable electricity, this final rule fully accounts for the critical service utilities provide.

As with past rules under CAA section 111, this rule relies on proven technologies and measures to set achievable emission performance rates that will lead to cost-effective pollutant emission reductions, in this case CO_2 emission reductions at power plants, across the country. In fact, the emission guidelines reflect strategies, technologies and approaches already in widespread use by power companies and states. The vast preponderance of the input we received from stakeholders is supportive of this conclusion.

States will play a key role in ensuring that emission reductions are achieved at a reasonable cost. The experience of states in this regard is especially important because CAA section 111(d) relies on the well-established state-EPA partnership to accomplish the required CO_2 emission reductions. States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO_2 emission performance rates, and this final rule allows and encourages states to adopt the most effective set of solutions for their circumstances, taking account of cost and other considerations. This rulemaking, which will be implemented through the state-EPA partnership, is a significant step that will reduce air pollution, in this case GHG emissions, in the U.S. At the same time, the final rule greatly facilitates flexibility for EGUs by establishing a basis for states to set trading-based emission standards and compliance strategies. The rule establishes this basis by including both uniform emission performance rates for the two subcategories of sources and also state-specific rate- and mass-based goals.

This final rule is a significant step forward in implementing the President's Climate Action Plan.[3] To address the far-reaching harmful consequences and real economic costs of climate change, the President's Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and its harmful impacts on public health and the environment. Climate change is already occurring in this country, affecting the health, economic well-being and quality of life of Americans across the country, and especially those in the most vulnerable communities. This CAA section 111(d) rulemaking to reduce GHG emissions from existing power plants, and the concurrent CAA section 111(b) rulemaking to reduce GHG emissions from new, modified, and reconstructed power plants, implement one of the strategies of the Climate Action Plan.

Nationwide, by 2030, this final CAA section 111(d) existing source rule will achieve CO_2 emission reductions from the utility power sector of approximately 32 percent from CO_2 emission levels in 2005.

The EPA projects that these reductions, along with reductions in other air pollutants resulting directly from this rule, will result in net climate and health benefits of $25 billion to $45 billion in 2030. At the same time, coal and natural gas will remain the two leading sources of electricity generation in the U.S.,

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[3] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

with coal providing about 27 percent of the projected generation and natural gas providing about 33 percent of the projected generation.

3. Summary of Major Provisions

a. *Overview.* The fundamental goal of this rule is to reduce harmful emissions of CO_2 from fossil fuel-fired EGUs in accordance with the requirements of the CAA. The June 2014 proposal for this rule was designed to meet this overarching goal while accommodating two important objectives. The first was to establish guidelines that reflect both the unique interconnected and interdependent manner in which the power system operates and the actions, strategies, and policies states and utilities have already been undertaking that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities with broad flexibility and choice in meeting those requirements in order to minimize costs to ratepayers and to ensure the reliability of electricity supply. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these objectives.

While our consideration of public input and additional information has led to notable revisions from the emission guidelines we proposed in June 2014, the proposed guidelines remain the foundation of this final rule. These final guidelines build on the progress already underway to reduce the carbon intensity of power generation in the U.S., especially through the lowest carbon-intensive technologies, while reflecting the unique interconnected and interdependent system within which EGUs operate.

Thus, the BSER, as determined in these guidelines, incorporates a range of CO_2-reducing actions, while at the same time adhering to the fundamental approach the EPA has relied on for decades in implementing section 111 of the CAA. Specifically, in making its BSER determination, the EPA examined not only actions, technologies and measures already in use by EGUs and states, but also deliberately incorporated in its identification of the BSER the unique way in which affected EGUs actually operate in providing electricity services. This latter feature of the BSER mirrors Congress' approach to regulating air pollution in this sector, as exemplified by Title IV of the CAA. There, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the sulfur dioxide (SO_2) portion of that program with express recognition of the utility power sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on RE and even on demand-side EE. The result of our following Congress' recognition of the interdependent operation of EGUs within an interconnected grid is the incorporation in the BSER of measures, such as shifting generation to lower-emitting NGCC units and increased use of RE, that rely on the current interdependent operation of EGUs. As we noted in the proposal and note here as well, the EPA undertook an unprecedented and sustained process of engagement with the public and stakeholders. It is, in many ways, as a direct result of public discussion and input that the EPA came to recognize the substantial extent to which the BSER needed to account for the unique interconnected and interdependent operations of

EGUs if it was to meet the criteria on which the EPA has long relied in making BSER determinations.

Equally important, these guidelines offer states and owners and operators of EGUs broad flexibility and latitude in complying with their obligations. Because affordability and electricity system reliability are of paramount importance, the rule provides states and utilities with time for planning and investment, which is instrumental to ensuring both manageable costs and system reliability, as well as to facilitating clean energy innovation. The final rule continues to express the CO_2 emission reduction requirements in terms of state goals, as well as in terms of emission performance rates for the two subcategories of affected EGUs, reflecting the particular mix of power generation in each state, and it continues to provide until 2030, fifteen years from the date of this final rule, for states and sources to achieve the CO_2 reductions. Numerous commenters, including most sources, states and energy agencies, indicated that this was a reasonable timeframe. The final guidelines also continue to provide an option where programs beyond those directly limiting power plant emission rates can be used for compliance (*i.e.*, policies, programs and other measures). The final rule also continues to allow, but not require, multi-state approaches. Finally, EPA took care to ensure that states could craft their own emissions reduction trajectories in meeting the interim goals included in this final rule.

b. *Opportunities for states.* As stated above, the final guidelines are designed to build on and reinforce progress by states, cities and towns, and companies on a growing variety of sustainable strategies to reduce power sector CO_2 emissions. States, in their CAA section 111(d) plans, will be able to rely on, and extend, programs they may already have created to address emissions of air pollutants, and in particular CO_2, from the utility power sector or to address the sector from an overall perspective. Those states committed to Integrated Resource Planning (IRP) will be able to establish their CO_2 reduction plans within that framework, while states with a more deregulated power sector system will be able to develop CO_2 reduction plans within that specific framework. Each state will have the opportunity to take advantage of a wide variety of strategies for reducing CO_2 emissions from affected EGUs, including demand-side EE programs and mass-based trading, which some suggested in their comments. The EPA and other federal entities, including the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Agriculture (USDA), among others, are committed to sharing expertise with interested states as they develop and implement their plans.

States will be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this final action to reduce costs to consumers, minimize stranded assets, and spur private investments in RE and EE technologies and businesses. They may also, if they choose, work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The final rule gives states the flexibility to implement a broad range of approaches that recognize that the utility power sector is made up of a diverse range of companies of various sizes that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities, some of which are likely to have more direct access than others to certain types of GHG emission reduction opportunities, but all of which have a wide range of opportunities to achieve reductions or acquire clean generation.

Again, with features that facilitate mass-based and/or interstate trading, the final guidelines also empower affected EGUs to pursue a broad range of choices for compliance and for integrating compliance action with the full range of their investments and operations.

c. *Main elements*. This final rule comprises three main elements: (1) Two subcategory-specific CO_2 emission performance rates resulting from application of the BSER to the two subcategories of affected EGUs; (2) state-specific CO_2 goals, expressed as both emission rates and as mass, that reflect the subcategory-specific CO_2 emission performance rates and each state's mix of affected EGUs the two performance rates; and (3) guidelines for the development, submittal and implementation of state plans that implement those BSER emission performance rates either through emission standards for affected EGUs, or through measures that achieve the equivalent, in aggregate, of those rates as defined and expressed in the form of the state goals.

In this final action, the EPA is setting emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs—fossil fuel-fired electric utility steam-generating units and stationary combustion turbines. These rates, applied to each state's particular mix of fossil fuel-fired EGUs, generate the state's carbon intensity goal for 2030 (and interim rates for the period 2022–2029). Each state will determine whether to apply these to each affected EGU or to take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal. The EPA does not prescribe how a state must meet the emission guidelines, but, if a state chooses to take the path of meeting a state goal, these final guidelines identify the methods that a state can or, in some cases, must use to demonstrate that the combination of measures and standards that the state adopts meets its state-level CO_2 goals. While the EPA accomplishes the phase-in of the interim goal by way of annual emission performance rates, states and EGUs may meet their respective emission reduction obligations "on average" over that period following whatever emission reduction trajectory they determine to pursue over that period.

CAA section 111(d) creates a partnership between the EPA and the states under which the EPA establishes emission guidelines and the states take the lead on implementing them by establishing emission standards or creating plans that are consistent with the EPA emission guidelines. The EPA recognizes that each state has differing policy considerations—including varying regional emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (*e.g.*, utility regulatory structure and generation mix) also differ. Therefore, as in the proposal, each state will have the latitude to design a program to meet source-category specific emission performance rates or the equivalent statewide rate- or mass-based goal in a manner that reflects its particular circumstances and energy and environmental policy objectives. Each state can do so on its own, or a state can collaborate with other states and/or tribal governments on multi-state plans, or states can include in their plans the trading tools that EGUs can use to realize additional opportunities for cost savings while continuing to operate across the interstate system through which electricity is produced. A state would also have the option of adopting the model rules for either a rate- or a mass-based program that the EPA is proposing concurrently with this action.[4]

To facilitate the state planning process, this final rule establishes guidelines for the development, submittal, and implementation of state plans. The final rule describes the components of a state plan, the additional latitude states have in developing strategies to meet the emission guidelines, and the options they have in the timing of submittal of their plans. This final rule also gives states considerable flexibility with respect to the timeframes for plan development and implementation, as well as the choice of emission reduction measures. The final rule provides up to fifteen years for full implementation of all emission reduction measures, with incremental

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[4] The EPA's proposed CAA section 111(d) federal plan and model rules for existing fossil fuel-fired EGUs are being published concurrently with this final rule.

steps for planning and then for demonstration of CO_2 reductions that will ensure that progress is being made in achieving CO_2 emission reductions. States will be able to choose from a wide range of emission reduction measures, including measures that are not part of the BSER, as discussed in detail in section VIII.G of this preamble.

d. *Determining the BSER*. In issuing this final rulemaking, the EPA is implementing statutory provisions that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in numerous subsequent CAA section 111 rulemakings. These requirements call on the EPA to develop emission guidelines that reflect the EPA's determination of the "best system of emission reduction . . . adequately demonstrated" for states to follow in formulating plans to establish emission standards to implement the BSER.

As the EPA has done in making BSER determinations in previous CAA section 111 rulemakings, for this final BSER determination, the agency considered the types of strategies that states and owners and operators of EGUs are already employing to reduce the covered pollutant (in this case, CO_2) from affected sources (in this case, fossil fuel-fired EGUs).[5]

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[5] The final emission guidelines for landfill gas emissions from municipal solid waste landfills, published on March 12, 1996, and amended on June 16, 1998 (61 FR 9905 and 63 FR 32743, respectively), provide an example, as the guidelines allow either of two approaches for controlling landfill gas—by recovering the gas as a fuel, for sale, and removing from the premises, or by destroying the organic content of the gas on the premises using a

In so doing, as has always been the case, our considerations were not limited solely to specific technologies or equipment in hypothetical operation; rather, our analysis encompassed the full range of operational practices, limitations, constraints and opportunities that bear upon EGUs' emission performance, and which reflect the unique interconnected and interdependent operations of EGUs and the overall electricity grid.

In this final action, the agency has determined that the BSER comprises the first three of the four proposed "building blocks," with certain refinements to the three building blocks.

The three building blocks are:

1. Improving heat rate at affected coal-fired steam EGUs.

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for generation from higher-emitting affected steam generating units.

3. Substituting increased generation from new zero-emitting renewable energy generating capacity for generation from affected fossil fuel-fired generating units.

These three building blocks are approaches that are available to all affected EGUs, either through direct investment or operational shifts or through emissions trading where states, which must establish emission standards for affected EGUs, do so by incorporating

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control device. Recovering the gas as a fuel source was a practice already being used by some affected sources prior to promulgation of the rulemaking.

emissions trading.[6] At the same time, and as we noted in the proposal, there are numerous other measures available to reduce CO_2 emissions from affected EGUs, and our determination of the BSER does not necessitate the use of the three building blocks to their maximum extent, or even at all. The building blocks and the BSER determination are described in detail in section V of this preamble.

e. *CO_2 state-level goals and subcategory-specific emission performance rates.*

(1) *Final CO_2 goals and emission performance rates.*

In this action, the EPA is establishing CO_2 emission performance rates for two subcategories of affected EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines. For fossil fuel-fired steam generating units, we are finalizing an emission performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing an emission performance rate of 771 lb CO_2/MWh. As we did at proposal, for each state, we are also promulgating rate-based CO_2 goals that are the weighted aggregate of the emission performance rates for the state's EGUs. To ensure that states and sources can choose additional alternatives in meeting their obligations, the EPA is also promulgating each state's goal expressed as a CO_2

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[6] The EPA notes that, in quantifying the emission reductions that are achievable through application of the BSER, some building blocks will apply to some, but not all, affected EGUs. Specifically, building block 1 will apply to affected coal-fired steam EGUs, building block 2 will apply to all affected steam EGUs (both coal-fired and oil/gas-fired), and building block 3 will apply to all affected EGUs.

mass goal. The inclusion of mass-based goals, along with information provided in the proposed federal plan and model rules that are being issued concurrently with this rule, paves the way for states to implement mass-based trading, as some states have requested, reflecting their view that mass-based trading provides significant advantages over rate-based trading.

Affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state, must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate- and mass-based goals, by 2030.

(2) *Interim CO_2 emission performance rates and state-specific goals.*

The best system of emission reduction includes both the measures for reducing CO_2 emissions and the timeframe over which they can be implemented. In this final action, the EPA is establishing an 8-year interim period, beginning in 2022 instead of 2020, over which to achieve the full required reductions to meet the CO_2 performance rates, a commencement date more than six years from October 23, 2015, the date of this rulemaking. This 8-year interim period from 2022 through 2029 is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates. The interim steps are presented both in terms of emission performance rates for the two subcategories of affected EGUs and in terms of state goals, expressed both as a rate and as a mass. A state may adopt emission standards for its sources that are identical to these interim emission performance rates or, alternatively, adapt these steps to accommodate the timing of expected reductions, as long as the state's interim goal is met over the 8-year period.

f. *State plans*.[7]

In this action, the EPA is establishing final guidelines for states to follow in developing, submitting and implementing their plans. In developing plans, states will need to choose the type of plan they will develop. They will also need to include required plan components in their plan submittals, meet plan submittal deadlines, achieve the required CO_2 emission reductions over time, and provide for monitoring and periodic reporting of progress. As with the BSER determination, stakeholder comments have provided both data and recommendations to which these final guidelines are responsive.

(1) *Plan approaches*.

To comply with these emission guidelines, a state will have to ensure, through its plan, that the emission standards it establishes for its sources individually, in

[7] The CAA section 111(d) emission guidelines apply to the 50 states, 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. In this preamble, in instances where these governments are not specifically listed, the term "state" is used to represent them. Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with affected EGUs (Alaska and Hawaii) and the two U.S. territories with affected EGUs (Guam and Puerto Rico), we are not finalizing emission performance rates in those areas at this time, and those areas will not be required to submit state plans until we do.

aggregate, or in combination with other measures undertaken by the state, represent the equivalent of the subcategory-specific CO_2 emission performance rates. This final rule includes several options for state plans, as discussed in the proposal and in many of the comments we received.

First, in the final rule, states may establish emission standards for their affected EGUs that mirror the uniform emission performance rates for the two subcategories of sources included in this final rule. They may also pursue alternative approaches that adopt emission standards that meet the uniform emission performance rates, or emission standards that meet either the rate-based goal promulgated for the state or the alternative mass-based goal promulgated for the state. It is for the purpose of providing states with these choices that the EPA is providing state-specific rate-based and mass-based goals equivalent to the emission performance rates that the EPA is establishing for the two subcategories of fossil fuel-fired EGUs. A detailed explanation of rate- and mass-based goals is provided in section VII of this preamble and in a TSD.[8] In developing its plan, each state and eligible tribe electing to submit a plan will need to choose whether its plan will result in the achievement of the CO_2 emission performance rates, statewide rate-based goals, or statewide mass-based goals by the affected EGUs.

The second major set of options provided in the final rule includes the types of measures states may rely on

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[8] The CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, available in the docket for this rulemaking.

through the state plans. A state will be able to choose to establish 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, which we refer to as the "emission standards approach." Alternatively, a state can adopt a "state measures approach," which would result in the affected EGUs meeting the statewide mass-based goal by allowing a state to rely upon state-enforceable measures on entities other than affected EGUs, in conjunction with any federally enforceable emission standards the state chooses to impose on affected EGUs. With a state measures approach, the plan must also include a contingent backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the required emission reductions on schedule. A state would have the option of basing its backstop emission standards on the model rule, which focuses on the use of emissions trading as the core mechanism and which the EPA is proposing today. A state that adopts a state measures approach must use its mass CO_2 emission goal as the metric for demonstrating plan performance.

The final rule requires that the state plan submittal include a timeline with all of the programmatic plan milestone steps the state will take between the time of the state plan submittal and the year 2022 to ensure that the plan is effective as of 2022. States must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic plan milestone steps that the state indicated it would take during the period from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022.

The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 emission reductions, and implementation of corrective actions, in the event that the state fails to achieve required emission levels in a timely fashion. Beginning January 1, 2025, and then January 1, 2028, January 1, 2030, and then every two calendar years thereafter, the state will be required to compare emission levels achieved by affected EGUs in the state with the emission levels projected in the state plan and report the results of that comparison to the EPA by July 1 of those calendar years.

Existing state programs can be aligned with the various state plan options further described in Section VIII. A state plan that uses one of the finalized model rules, which the EPA is proposing concurrently with this action, could be presumptively approvable if the state plan meets all applicable requirements.[9] The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass basis. They also address several key policy considerations that states can be expected to contemplate in developing their plans.

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[9] The EPA would take action on such a state plan through independent notice and comment rulemaking.

State plan approaches and plan guidelines are explained further in section VIII of this preamble.

(2) *State plan components and approvability criteria.*

The EPA's implementing regulations provide certain basic elements required for state plans submitted pursuant to CAA section 111(d).[10] In the proposal, the EPA identified certain additional elements that should be contained in state plans. In this final action, in response to comments, the EPA is making several revisions to the components required in a state plan submittal and is also incorporating the approvability criteria into the final list of components required in a state plan submittal. In addition, we have organized the state plan components to reflect: (1) Components required for all state plan submittals; (2) additional components required for the emission standards approach; and (3) additional components required for the state measures approach.

All state plans must include the following components:

- Description of the plan
- Applicability of state plans to affected EGUs
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission performance rates or state CO_2 goal[11]

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[10] 40 CFR 60.23.

[11] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

- Monitoring, reporting and recordkeeping requirements for affected EGUs
- State recordkeeping and reporting requirements
- Public participation and certification of hearing on state plan
- Supporting documentation

Also, in submitting state plans, states must provide documentation demonstrating that they have considered electric system reliability in developing their plans.

Further, in this final rule, the EPA is requiring states to demonstrate how they are meaningfully engaging all stakeholders, including workers and low-income communities, communities of color, and indigenous populations living near power plants and otherwise potentially affected by the state's plan. In their plan submittals, states must describe their engagement with their stakeholders, including their most vulnerable communities. The participation of these communities, along with that of ratepayers and the public, can be expected to help states ensure that state plans maintain the affordability of electricity for all and preserve and expand jobs and job opportunities as they move forward to develop and implement their plans.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.

- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.

- Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

(3) *Timing and process for state plan submittal and review.*

Because of the compelling need for actions to begin the steps necessary to reduce GHG emissions from EGUs, the EPA proposed that states submit their plans within 13 months of the date of this final rule and that reductions begin in 2020. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for a 2-year extension until September 6, 2018, for both individual and multi-state plans, to provide a total of 3 years for states to submit a final plan if an extension is received. Specifically, the final rule requires each state to submit a final plan by

September 6, 2016. Since some states may need more than one year to complete all of the actions needed for their final state plans, including technical work, state legislative and rulemaking activities, a robust public participation process, coordination with third parties, coordination among states involved in multi-state plans, and consultation with reliability entities, the EPA is allowing an optional two-phased submittal process for state plans. 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. For the extension to be granted, the initial submittal must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. These components are: An identification of final plan approach or approaches under consideration, including a description of progress made to date; an appropriate explanation for why the state needs additional time to submit a final plan beyond September 6, 2016; and a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan, as described in section VIII.E of this preamble. As further described in section VIII.B of this preamble, the EPA is establishing a CEIP in order to promote early action. States' participation in the CEIP is optional. In order for a state to participate in the program, it must include in its initial submittal, if applicable, a non-binding statement of intent to participate in the CEIP; if a state is submitting a final plan by September 6, 2016, it must include such a statement of intent as part of its supporting documentation for the plan.

If the initial submittal includes those components and if the EPA does not notify the state that the initial submittal does not contain the required components, then, within 90 days of the submittal, the extension of time to submit a final plan will be deemed granted. A state will then have until no later than September 6, 2018, to submit a final plan. The EPA will also be working with states during the period after they make their initial submittals and provide states with any necessary information and assistance during the 90-day period. Further, states participating in a multi-state plan may submit a single joint plan on behalf of all of the participating states.

States and tribes that do not have any affected EGUs in their jurisdictional boundaries may provide emission rate credits (ERCs) to adjust CO_2 emissions, provided they are connected to the contiguous U.S. grid and meet other requirements for eligibility. There are certain limitations and restrictions for generating ERCs, and these, as well as associated requirements, are explained in section VIII of this preamble.

Following submission of final plans, the EPA will review plan submittals for approvability. Given a similar timeline accorded under section 110 of the CAA, and the diverse approaches states may take to meet the CO_2 emission performance rates or equivalent statewide goals in the emission guidelines, the EPA is extending the period for EPA review and approval or disapproval of plans from the four-month period provided in the EPA implementing regulations to a twelve-month period. This timeline will provide adequate time for the EPA to review plans and follow notice-and-comment rulemaking procedures to ensure an opportunity for public comment. The EPA, especially through our regional offices, will be available to work with states as they develop their plans, in order to make review of submitted plans more straightforward and to minimize the chances of unexpected issues that could slow down approval of state plans.

(4) *Timing for implementing the CO_2 emission guidelines*.

The EPA recognizes that the measures states and utilities have been and will be taking to reduce CO_2 emissions from existing EGUs can take time to implement. We also recognize that investments in low-carbon intensity and RE and in EE strategies are currently underway and in various stages of planning and implementation widely across the country. We carefully reviewed information submitted to us regarding the feasible timing of various measures and identifying concerns that the required CO_2 emission reductions could not be achieved as early as 2020 without compromising electric system reliability, imposing unnecessary costs on ratepayers, and requiring investments in more carbon-intensive generation, while diverting investment in cleaner technologies. The record is compelling. To respond to these concerns and to reflect the period of time required for state plan development and submittal by states, review and approval by the EPA, and implementation of approved plans by states and affected EGUs, the EPA is determining in this final rule that affected EGUs will be required to begin to make reductions by 2022, instead of 2020, as proposed, and meet the final CO_2 emission performance rates or equivalent statewide goals by no later than 2030. The EPA is establishing an 8-year interim period that begins in 2022 and goes through 2029, and which is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim goal. Affected EGUs must meet each of the interim period step 1, 2, and 3 CO_2 emission performance rates, or, following the emissions reduction trajectory designed by the state itself, must meet the equivalent statewide interim period goals, on average, that a state may establish over the 8-year period from 2022–2029. The CAA section 111(d) plan must include those specific requirements. Affected EGUs must also achieve the final CO_2 performance rates or the equivalent statewide goal by 2030 and maintain that level subsequently. This approach reflects adjustments to the timeframe over which reductions must be achieved that mirror the determination of the final BSER, which incorporates the phasing in of the BSER measures in keeping with the achievability of those measures. The agency believes that this approach to timing is reasonable and appropriate, is consistent with many of the comments we received, and will best support the optimization of overall CO_2 reductions, ratepayer affordability and electricity system reliability.

The EPA recognizes that successfully achieving reductions by 2022 will be facilitated by actions and investments that yield CO_2 emission reductions prior to 2022. The final guidelines include provisions to encourage early actions. States will be able to take advantage of the impacts of early investments that occur prior to the beginning of a plan performance period. Under a mass-based plan, those impacts will be reflected in reductions in the reported CO_2 emissions of affected EGUs during the plan performance period. Under a rate-based plan, states may recognize early actions implemented after 2012 by crediting MWh of electricity generation and savings that are achieved by those measures during the interim and final plan performance periods. This provision is discussed in section VIII.K of the preamble.

In addition, to encourage early investments in RE and demand-side EE, the EPA is establishing the CEIP. Through this program, detailed in section VIII.B of this preamble, states will have the opportunity to award allowances and ERCs to qualified providers that make early investments in RE, as well as in demand-side EE programs implemented in low-income communities. Those 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.

The EPA will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

The CEIP can play an important role in supporting one of the critical policy benefits of this rule. The incentives and market signal generated by the CEIP can help sustain the momentum toward greater RE investment in the period between now and 2022 so as to offset any dampening effects that might be created by setting the period for mandatory reductions to begin in 2022, two years later than at proposal.

(5) *Community and environmental justice considerations.*

Climate change is an environmental justice issue. Low-income communities and communities of color already overburdened by pollution are disproportionately affected by climate change and are less resilient than others to adapt to or recover from climate-change impacts. While this rule will provide broad benefits to communities across the nation by reducing GHG emissions, it will be particularly beneficial to populations that are disproportionately vulnerable to the impacts of climate change and air pollution.

Conventional pollutants emitted by power plants, such as particulate matter (PM), SO_2, hazardous air pollutants (HAP), and nitrogen oxides (NO_X), will also be reduced as the plants reduce their carbon emissions. These pollutants can have significant adverse local and regional health impacts. The EPA analyzed the communities in closest proximity to power plants and found that they include a higher percentage of communities of color and low-income communities than national averages. We thus expect an important co-benefit of this rule to be a reduction in the adverse health impacts of air pollution on these low-income communities and communities of color. We refer to these communities generally as "vulnerable" or "overburdened," to denote those communities least resilient to the impacts of climate change and central to environmental justice considerations.

While pollution will be cut from power plants overall, there may be some relatively small number of coal-fired plants whose operation and corresponding emissions increase as energy providers balance energy production across their fleets to comply with state plans. In addition, a number of the highest-efficiency natural gas-fired units are also expected to increase operations, but they have correspondingly low carbon emissions and are also characterized by low emissions of the conventional pollutants that contribute to adverse health effects in nearby communities and regionally. The EPA strongly encourages states to evaluate the effects of their plans on vulnerable communities and to take the steps necessary to ensure that all communities benefit from the implementation of this rule. In order to identify whether state plans are causing any adverse impacts on overburdened communities, mindful that substantial overall reductions, nevertheless, may be accompanied by potential localized increases, the EPA intends to perform an assessment of the implementation of this rule to determine whether it and other air quality rules are leading to improved air quality in all areas or whether there are localized impacts that need to be addressed.

Effective engagement between states and affected communities is critical to the development of state plans. The EPA encourages states to identify communities that may be currently experiencing adverse, disproportionate impacts of climate change and air pollution, how state plan designs may affect them, and how to most effectively reach out to them. This final rule requires that states include in their initial submittals a description of how they engaged with vulnerable communities as they developed their initial submittals, as well as the means by which they intend to involve communities and other stakeholders as they develop their final plans. The EPA will provide training and other resources for states and communities to facilitate meaningful engagement.

In addition to the benefits for vulnerable communities from reducing climate change impacts and effects of conventional pollutant emissions, this rule will also help communities by moving the utility industry toward cleaner generation and greater EE. The federal government is committed to ensuring that all communities share in these benefits.

The EPA also encourages states to consider how they may incorporate approaches already used by other states to help low-income communities share in the investments in infrastructure, job creation, and other benefits that RE and demand-side EE programs provide, have access to financial assistance programs, and minimize any adverse impacts that their plans could have on communities. To help support states in taking concrete actions that provide economic development, job and electricity bill-cutting benefits to low-income communities directly, the EPA has designed the CEIP specifically to target the incentives it creates on investments that benefit low-income communities.

Community and environmental justice considerations are discussed further in section IX of this preamble.

(6) *Addressing employment concerns.*

In addition, the EPA encourages states in designing their state plans to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are realized. To the extent possible, states should try to assure that communities that can be expected to experience job losses can also take advantage of the opportunities for job growth or otherwise transition to healthy, sustainable economic growth. The President has proposed the POWER+ Plan to help communities impacted by power sector transition. The POWER+ plan invests in workers and jobs, addresses important legacy costs in coal country, and drives development of coal technology. [12] Implementation of one key part of the POWER+ Plan, the Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) initiative, has already begun. The POWER initiative specifically targets economic and workforce development assistance to communities affected by ongoing changes in the coal industry and the utility power sector.[13]

(7) *Electric system reliability.*

In no small part thanks to the comments we received and our extensive consultation with key agencies responsible for reliability, including FERC and DOE, among others, along with EPA's longstanding principles in setting emission standards for the utility power sector, these guidelines reflect the

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[12] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.*

[13] *http://www.eda.gov/power/.*

paramount importance of ensuring electric system reliability. The input we received on this issue focused heavily on the extent of the reductions required at the beginning of the interim period, proposed as 2020. We are addressing these concerns in large part by moving the beginning of the period for mandatory reductions under the program from 2020 to 2022 and significantly adjusting the interim goals so that they provide a less abrupt initial reduction expectation. This, in turn, will provide states and utilities with a great deal more latitude in determining their emission reduction trajectories over the interim period. As a result, there will be more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choice of compliance strategies, all within the existing extensive structure of energy planning at the state and regional levels. These adjustments in the interim goals are supported by the information in the record concerning the time needed to develop and implement reductions under the BSER. In addition, the various forms of flexibility retained and enhanced in this final rule, including opportunities for trading within and between states, and other multi-state compliance approaches, will further support electric system reliability.

The final guidelines address electric system reliability in several additional important ways. Numerous commenters urged us to include, as part of the plan development or approval process, input from review by energy regulatory agencies and reliability entities. In the final rule, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. Second, we recognize that issues may arise during the implementation of the guidelines that may warrant adjustments to a state's plan in order to maintain electric system reliability. The final guidelines make clear that states have the ability to propose amendments to approved 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.

As a final element of reliability assurance, the rule also 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.

We anticipate that these situations will be extremely rare because the states have the flexibility to craft requirements for their EGUs that will provide long averaging periods and/or compliance mechanisms, such as trading, whose inherent flexibility will make it unlikely that an individual unit will find itself in this kind of situation. As one example, under compliance regimes that allow individual EGUs to establish compliance through the acquisition and holding of allowances or ERCs equal to their emissions, an EGU's need to continue to operate—and emit—for the purposes of ensuring system reliability will not put the EGU into non-compliance, provided, of course, it obtains the needed allowances or credits in a timely fashion. We, nevertheless, agree with many commenters that it is prudent to provide an electric system reliability safety valve as a precaution.

Finally, the EPA, DOE and FERC have agreed to coordinate their efforts, at the federal level, to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have set out a memorandum that reflects their joint understanding of how they will work together to monitor implementation, share information, and to resolve any difficulties that may be encountered.

As a result of the many features of this final rule that provide states and affected EGUs with meaningful time and decision making latitude, we believe that the comprehensive safeguards already in place in the U.S. to ensure electric system reliability will continue to operate effectively as affected EGUs reduce their CO_2 emissions under this program.

(8) *Outreach and resources for stakeholders*.

To provide states, U.S. territories, tribes, utilities, communities, and other interested stakeholders with understanding about the rule requirements, and to provide efficiencies where possible and reduce the cost and administrative burden, the EPA will continue to work with states, tribes, territories, and stakeholders to provide information and address questions about the final rule. Outreach will include opportunities for states and tribes to participate in briefings, teleconferences, and meetings about the final rule. The EPA's ten regional offices will continue to be the entry point for states, tribes and territories to ask technical and policy questions. The agency will host (or partner with appropriate groups to co-host) a number of webinars about various components of the final rule; these webinars are planned for the first two months after the final rule is issued. The EPA will also offer consultations with tribal governments. The EPA will continue outreach throughout the plan development and submittal process. The EPA will use information from this outreach process to inform the training and other tools that will be of most use to the state, tribes, and territories that are implementing the final rule.

The EPA has worked with communities, states, tribes and relevant associations to develop an extensive training plan that will continue in the months after the Clean Power Plan is finalized. The EPA has assembled resources from a variety of sources to create a comprehensive training curriculum for those implementing this rule. Recorded presentations from the EPA, DOE and other federal entities will be available for communities, states, and others involved in composing and participating in the development of state plans. This curriculum is available online at EPA's Air Pollution Training Institute.

The EPA also expects to issue guidance on specific topics. As guidance documents, tools, templates and other resources become available, the EPA, in consultation with DOE and other federal agencies, will continue to make these resources available via a dedicated Web site.[14]

We intend to continue to work actively with states and tribes, as appropriate, to provide information and technical support that will be helpful to them in developing and implementing their plans. The EPA will engage in formal consultations with tribal

[14] www.epa.gov/cleanpowerplantoolbox.

governments and provide training tailored to the needs of tribes and tribal governments.

Additional detail on aspects of the final rule is included in several technical support documents (TSDs) and memoranda that are available in the rulemaking docket.

4. Key Changes From Proposal

a. *Overview and highlights*. As noted earlier in this overview, the June 2014 proposal for the rule was designed to meet the fundamental goal of reducing harmful emissions of CO_2 from fossil fuel-fired EGUs in a manner consistent with the CAA requirements, while accommodating two important objectives. The first objective was to establish guidelines that reflect both the manner in which the power system operates and the actions and measures already underway across states and the utility power sector that are resulting in CO_2 emission reductions. The second objective was to provide states and utilities maximum flexibility, control and choice in meeting their compliance obligations. In this final rule, the EPA has focused on changes that, in addition to being responsive to the critical concerns and priorities of stakeholders, more fully accomplish these two crucial objectives.

To achieve these objectives, the June 2014 proposal featured several important elements: The building block approach for the BSER; state-specific, rather than source-specific, goals; a 10-year interim goal that could be met "on average" over the 10-year period between 2020 and 2029; and a "portfolio" option for state plans. These features were intended either to capture, in the emission guidelines, emission reduction measures already in widespread use or to maximize the range of choices that states and utilities could select in order to achieve their emission limitations at low cost while ensuring electric system reliability. In this final rule, we are retaining the key design elements of the proposal and making certain adjustments to respond to a variety of very constructive comments on ways that will implement the CAA section 111(d) requirements efficiently and effectively.

The building block approach is a key feature of the proposal that we are retaining in the final rule, but have refined to include only the first three building blocks and to reflect implementation of the measures encompassed in the building blocks on a broad regional grid-level. In the proposal, we expressed the emission limitation requirements reflecting the BSER in terms of the state goals in order to provide states with maximum flexibility and latitude. We viewed this as an important feature because each state has its own energy profile and state-specific policies and needs relative to the production and use of electricity. In the final rule, we extend that flexibility significantly in direct response to comments from states and utilities. The final rule establishes source-level emission performance rates for the source subcategories, while retaining state-level rate- and mass-based goals. One of the key messages conveyed by state and utility commenters was that the final rule should make it easier for states to adopt mass-based programs and for utilities accustomed to operating across broad multi-state grids to be able to avail themselves of more "ready-made" emissions trading regimes. The inclusion of both of these new features—

mass-based state goals in addition to rate-based goals, and source-level emission performance rates for the two subcategories of sources—is intended to make it easier for states and utilities to achieve these outcomes. In fact, these additions, together with the model rules and federal plan being proposed concurrently with this rule, should demonstrate the relative ease with which states can adopt mass-based trading programs, including interstate mass-based programs that lend themselves to the kind of interstate compliance strategies so well suited for integration with the current interstate operations of the overall utility grid.

Many stakeholders conveyed to the EPA that the proposal's interim goals for the 2020–2029 period were designed in a way that defeated the EPA's objective of allowing states and utilities to shape their emission reduction trajectories. They pointed out that, in many cases, the timing and stringency of the states' interim goals could require actions that could result in high costs, threaten electric system reliability or hinder the deployment of renewable technology. In response, the EPA has revised the interim goals in two critical ways. First, the period for mandatory reductions begin in 2022 rather than 2020; second, in keeping with the BSER, emission reduction requirements are phased in more gradually over the interim period. These changes will allow states and utilities to delineate their own emission reduction trajectories so as to minimize costs and foster broader deployment of RE technologies. The value of these changes is demonstrated by our analysis of the final rule, which shows lower program costs, especially in the early years of the interim period, and greater RE deployment, relative to the analysis of the proposed rule. At the same time, this re-design of the interim goals, together with refinements we have made to state plan requirements and the inclusion of a reliability safety valve, provide states, utilities and other entities with the ability to continue to guarantee system reliability.

b. *Outreach, engagement and comment record.* This final rule is the product of one of the most extensive and long-running public engagement processes the EPA has ever conducted, starting in the summer of 2013, prior to proposal, and continuing through December 2014, when the public comment period ended, and continuing beyond that with consultations and meetings with stakeholders. The result of this extensive consultation was millions of comments from stakeholders, which we have carefully considered over the past several months. The EPA gained crucial insights from the more than 4 million comments that the agency received on the proposal and associated documents leading to this final rulemaking. Comments were provided by stakeholders that include state environmental and energy officials, tribal officials, public utility commissioners, system operators, owners and operators of every type of power generating facility, other industry representatives, labor leaders, public health leaders, public interest advocates, community and faith leaders, and members of the public.

The insights gained from public comments contributed to the development of final emission guidelines that build on the proposal and the alternatives on which we sought comment. The modifications incorporated in the final guidelines are directly responsive to the comments we received from the many and diverse stakeholders. The improved guidelines reflect information and ideas that states and utilities provided to us about both the best approach to establishing CO_2 emission reduction requirements for EGUs and the most effective ways to create true flexibility for states and utilities in meeting these requirements. These final rules also reflect the results of EPA's robust consultation with federal, state and regional energy agencies and authorities, to ensure that the actions sources will take to reduce GHG emissions will not compromise electric system reliability or affordability of the U.S. electricity supply. Input and assistance from FERC and DOE have been particularly important in shaping some provisions in these final guidelines. At the same time, input from faith-based, community-based and environmental justice organizations, who provided thoughtful comments about the potential impacts of this rule on pollution levels in overburdened communities and economic impacts, including utility rates in low-income communities, is also reflected in this rule. The final rule also reflects our response to concerns raised by labor leaders regarding the potential effects on workers and communities of the transition away from higher-emitting power generation to lower- and zero-emitting power generation.

c. *Key changes*. The most significant changes in these final guidelines are: (1) The period for mandatory emission reductions beginning in 2022 instead of 2020 and a gradual application of the BSER over the 2022–2029 interim period, such that a state has substantial latitude in selecting its own emission reduction trajectory or "glide path" over that period, (2) a revised BSER determination that focuses on narrower generation options that do not include demand-side EE measures and that includes refinements to the building blocks, more complete incorporation in the BSER of the realities of electricity operations over the three regional interconnections, and up-to-date information about the cost and availability of clean generation options, (3) establishment of source-specific CO_2 emission performance rates that are uniform across the two fossil fuel-fired subcategories covered in these guidelines, as well as rate- and mass-based state goals, to facilitate emission trading, including interstate trading and, in particular, mass-based trading, (4) a variation on the proposal's "portfolio" option for state plans—called here the "state measures" approach—that continues to provide states flexibility while ensuring that all state plans have federally enforceable measures as a backstop, (5) additional, more flexible options for states and utilities to adopt multi-state compliance strategies, (6) an extension of up to two years available to all states for submittal of their final compliance plans following making initial submittals in 2016, (7) provisions to encourage actions that achieve early reductions, including a Clean Energy Incentive Program (CEIP), (8) a combination of provisions expressly designed to ensure electric system reliability, (9) the addition of employment considerations for states in plan development, and (10) the expansion of considerations and programs for low-income and vulnerable communities.

We provide summary explanations in the following paragraphs and more detailed explanations of all of these changes in later sections of this preamble and associated documents.

(1) *Mandatory reduction period beginning in 2022 and a gradual glide path.*

The proposal's mandatory emission reduction period beginning in 2020 and the trajectory of emission reduction requirements in the interim period were both the subjects of significant comment. Earlier this year, FERC conducted a series of technical conferences comprising one national session and three regional sessions. The information provided by workshop participants echoed much of the material that had been submitted to the comment record for this rulemaking. On May 15, 2015, the FERC Commissioners, drawing upon information highlighted at the technical conferences, transmitted to the EPA some suggestions for the final rule. In addition, via comments, states, utilities, and reliability entities asked us to ensure adequate time for them to implement strategies to achieve CO_2 reductions. They expressed concern that, in the proposal, at least some states would be required to reduce emissions in 2020 to levels that would require abrupt shifts in generation in ways that raised concerns about impacts to electric system reliability and ratepayer bills, as well as about stranded assets. To many commenters, the proposal's requirement for CO_2 emission reductions beginning in 2020, together with the stringency of the interim CO_2 goal, posed significant reliability implications, in particular. In this final rule, the agency is addressing these concerns, in part, by adjusting the compliance timeframe from a 10-year interim period that begins in 2020 to an 8-year interim period that begins in 2022, and by refining the approach for meeting interim CO_2 emission performance rates to be a gradual glide path separated into three steps, 2022–2024, 2025–2027, and 2028–2029, that is also achievable "on average" over the 8-year interim period. In response to the concerns of commenters that the proposal's 10-year interim target failed to afford sufficient flexibility, the final guidelines' approach will provide states with realistic options for customizing their emission reduction trajectories. Of equal importance, the approach provides more time for planning, consultation and decision making in the formulation of state plans and in EGUs' choices of compliance strategies. Both FERC's May 15, 2015 letter and the comment record, as well as other information sources, made it clear that providing sufficient time for planning and implementation was essential to ensuring electric system reliability.

The final guidelines' approach to the interim emission performance rates is the result of the application of the measures constituting the BSER in a more gradual way, reflecting stakeholder comments and information about the appropriate period of time over which those measures can be deployed consistent with the BSER factors of cost and feasibility. In addition to facilitating reliable system operations, these changes provide states and utilities with the latitude to consider a broader range of options to achieve the required reductions while addressing concerns about ratepayer impacts and stranded assets.

(2) *Revised BSER determination.*

Commenters urged the EPA to confine its BSER determination to actions that involve what they characterized as more "traditional" generation. While some stakeholders recognized demand-side EE as being an integral part of the electricity system, with many of the characteristics of more traditional generating resources, other stakeholders did not. As explained in section V.B.3.c.(8) below, 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. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination. Thus, neither the final guidelines' BSER determination nor the emission performance rates for the two subcategories of affected EGUs take into account demand-side EE. However, many commenters also urged the EPA to allow states and sources to rely on demand-side EE as an element of their compliance strategies, as demand-side EE is treated as functionally interchangeable with other forms of generation for planning and operational purposes, as EE measures are in widespread use across the country and provide energy savings that reduce emissions, lower electric bills, and lead to positive investments and job creation. We agree, and the final guidelines provide ample latitude for states and utilities to rely on demand-side EE in meeting emission reduction requirements.

In response to stakeholder comments on the first three building blocks and considerable data in the record, the EPA has made refinements to the building blocks, and these are reflected in the final BSER. Refinements include adoption of a modified approach to quantification of the RE component, exclusion of the proposed nuclear generation components, and adoption of a consistent regionalized approach to quantification of all three building blocks. The agency also recognizes the important functional relationship between the period of time over which measures are deployed and the stringency of emission limitations those measures can achieve practically and at reasonable cost. Therefore, the final BSER also reflects adjustments to the stringency of the building blocks, after consideration of more and less stringent levels, and refinements to the timeframe over which reductions must be achieved. Sections V.C through V.E of this preamble provide further information on the refinements made to the building blocks and the rationale for doing so.

Commenters pointed out—and practical experience confirms—what is widely known: That the utility power sector operates over regional interconnections that are not constrained by state borders. Across a variety of issues raised in the proposal, many commenters urged that the EPA take that reality into account in developing this final rule. Consequently, the BSER determination itself (as well as a number of new compliance features included in this final rule) and the resulting subcategory-specific emission performance rates take into account the grid-level operations of the source category.

The final guidelines' BSER determination also takes into account recent reductions in the cost of clean energy technology, as well as projections of continuing cost reductions, and continuing increases in RE deployment. We also updated the underlying analysis with the most recent Energy Information Administration (EIA) projections that show lower growth in electricity demand between 2020 and 2030 than previously projected. In keeping with these recent EIA projections, we expect the final guidelines will be more conducive to compliance, consistent with a strategy that allows for the cleanest power generation and greater CO_2 reductions in 2030 than the proposal. With a date of 2022, instead of 2020, as proposed, for the mandatory CO_2 emission reduction period to begin, the final guidelines reflect that the additional time aligns with the adoption of lower-cost clean technology and, thus, its incorporation in the BSER at higher levels. At the same time, the 2022–2029 interim period will more easily allow for companies to take advantage of improved clean energy technologies as potential least cost options.

(3) *Uniform emission performance rates.*

Some stakeholders commented that the proposal's approach of expressing the BSER in terms of state-specific goals deviated from the requirements of CAA section 111 and from previous new source performance standards (NSPS). The effect, they stated, was that the proposal created de facto emission standards for all affected EGUs but that these de facto standards varied widely depending on the state in which a given EGU happened to be located. Instead, these and other commenters stated, section 111 requires that EPA establish the BSER specifically for affected sources, rather than by means of merely setting state-specific goals, and that these standards be uniform. Still other commenters observed that the effect of the approach taken in the proposal of applying the BSER to each state's fleet was to put a greater burden of reductions on lower-emitting or less carbon-intensive states and a lesser emission reduction burden on sources and states that were higher-emitting or more carbon-intensive. This, they argued, was both inequitable and at odds with the way in which NSPS have been applied in the past, where the higher-emitting sources have made the greater and more cost-effective reductions, while lower-emitting sources, whose reduction opportunities tend to be less cost-effective, have been required to make fewer reductions to meet the applicable standard.

At the same time, state and utility commenters expressed concern that relying on state-specific goals and state-by-state planning could introduce complexity into the otherwise seamless integrated operation of affected EGUs across the multi-state grids on which system operators, states and utilities currently rely and intend to continue to rely. Accordingly, they recommended that the final guidelines facilitate emissions trading, in particular interstate trading, which would enable EGU operators to integrate compliance with CO_2 emissions limitations with facility and grid-level operations. These sets of comments intersected at the point at which they focused on the fact that it is at the source level at which the standard is set for NSPS and at the source level at which compliance must be achieved.

The EPA carefully considered these comments and while we believe that the approach we took at proposal was well-founded and reflected a number of important considerations, we have concluded that there is a way to address these concerns while expanding upon the advantages offered by the proposal. Accordingly, the final guidelines establish uniform rates for the two subcategories of sources—an approach that is valuable for creating greater equity between and among utilities and states with widely varying emission levels and for expanding the flexibility of the program, especially in ways that have been identified as important to utilities and states. Specifically, the final guidelines express the BSER by means of performance-based CO_2 emission rates that are uniform across each of two subcategories—fossil fuel-fired electric steam generating units and stationary combustion turbines—for the affected EGUs covered by the guidelines. The rates are determined, in part, by applying the methodology identified in the Notice of Data Availability (NODA) published on October 30, 2014, which was based on the proposal's building block approach. The final guidelines also maintain the approach adopted in the proposal of establishing state-level goals; in the final rule, those goals are equal to the weighted aggregate of the two emission performance rates as applied to the EGUs in each state.

This approach rectifies what would have been an inefficient, unintended outcome of putting the greater reduction burden on lower-emitting sources and states while exempting higher-emitting sources and states. Expressing the BSER by means of these rates also augments the range of options for both states and EGUs for securing needed flexibility. Inclusion of state goals creates latitude for states as to how they will meet the guidelines. States also may meet the guideline requirements by adopting the CO_2 emission performance rates as emission standards that apply to the affected EGUs in their jurisdiction. Such an approach would lend itself to the ready establishment of intra-state and interstate trading, with the uniform rate-based standards of performance established for each EGU as the basis for such trading. At the same time, as at proposal, each state also has the option of complying with these guidelines by adopting a plan that takes a different approach to setting standards of performance for its EGUs and/or by applying complementary or alternative measures to meet the state goal set by these guidelines—as either a rate or a mass total.

During the outreach process and through comments, a number of state officials and other stakeholders expressed concern that the EPA's approach at proposal necessitated or represented a significant intrusion into state-level energy policy-making, drawing the EPA well beyond the bounds of its CAA authority and expertise. In fact, these final guidelines are entirely respectful of the EPA's responsibility and authority to regulate sources of air pollution. Instead, by establishing and operating through uniform performance rates for the two subcategories of sources that can be applied by states at the individual source level and that can readily be implemented through emission standards that incorporate emissions trading, these final guidelines align with the approach Congress and the EPA have consistently taken to regulating emissions from this and other industrial sectors, namely setting source-level, source category-wide standards that individual sources can meet through a variety of technologies and measures.

We emphasize, at the same time, that while the final guidelines express the BSER by means of source-level CO_2 emission performance rates, as well as state-level goals, as at proposal, each state will have a goal reflecting its particular mix of sources, and the final guidelines retain the flexibility inherent in the proposal's state-specific goals approach (and, as discussed in section VIII of this preamble, enhanced in various ways). Thus, in keeping with the proposal's flexibility, states may choose to adopt either the emission performance rates as emission standards for their sources, set different but, in the aggregate, equivalent rates, or fulfill their obligations by meeting their respective individual state goals.

(4) *State plan approaches*.

Commenters expressed support for the objectives served by the "portfolio" option in the state plan approaches included at proposal, but many raised concerns about its legality, with respect, in particular, to the CAA's enforceability requirements. Some of these commenters identified a "state commitment approach" with backstop measures as a variation of the "portfolio" approach that would retain the benefits of the "portfolio" approach while resolving legal and enforceability concerns. In this final rule, in response to stakeholder comments on the portfolio approach and alternative approaches, the EPA is finalizing two approaches: A source-based "emission standards" approach, and a "state measures" approach. Through the latter, states may adopt a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable. In addition, states would be required to include federally enforceable backstop measures applicable to each affected EGU in the event that the measures included in the state plan failed to achieve the state plan's emissions reduction trajectory. Under these guidelines, states can implement the BSER through standards of performance incorporating the uniform performance rates or alternative but in the aggregate equivalent rates, or they can adopt plans that achieve in aggregate the equivalent of the subcategory-specific CO_2 emission performance rates by relying on other measures undertaken by the state that complement source-specific requirements or, save for the contingent backstop requirement, supplant them entirely. This revision provides consistency in the treatment of sources while still providing maximum flexibility for states to design their plans around reduction approaches that best suit their policy objectives.

(5) *Emission trading programs.*

Many state and utility commenters supported the use of mass-based and rate-based emission trading programs in state plans, including interstate emission trading programs, and either pointed out obstacles to establishing such programs or suggested approaches that would enhance states' and utilities' ability to create and participate in such programs.

Through a combination of features retained from the proposal and changes made to the proposal, these final guidelines provide states and utilities with a panoply of tools that greatly facilitate their putting in place and participating in emissions trading programs. These include: (1) Expressing BSER in uniform emission performance rates that states may rely on in setting emission standards for affected EGUs such that EGUs operating under such standards readily qualify to trade with affected EGUs in states that adopt the same approach, (2) promulgating state mass goals so that states can move quickly to establish mass-based programs such that their affected EGUs readily qualify to trade with affected EGUs in states that adopt the same approach, and (3) providing EPA resources and capacity to create a tracking system to support state emissions trading programs.

(6) *Extension of plan submittal date.*

Stakeholders, particularly states, provided compelling information establishing that it could take longer than the agency initially anticipated for the states to develop and submit their required plans. While the approach at proposal reflected the EPA's conclusion that it was essential to the environmental and economic purposes of this rulemaking that utilities and states establish the path towards emissions reductions as early as possible, we recognize commenters' concerns. To strike the proper balance, the EPA has developed a revised state plan submittal schedule. For states that cannot submit a final plan by September 6, 2016, the EPA is requiring those states to make an initial submittal by that date to assure that states begin to address the urgent needs for reductions quickly, and is providing until September 6, 2018, for states to submit a final plan, if an extension until that date is justified, to address the concern that a submitting state needs more time to develop comprehensive plans that reflect the full range of the state's and its stakeholders' interests.

(7) *Provisions to encourage early action.*

Many commenters supported providing incentives for states and utilities to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. We also received comments from stakeholders regarding the disproportionate burdens that some communities already bear, and stating that all communities should have equal access to the benefits of clean and affordable energy. The EPA recognizes the validity and importance of these perspectives, and as a result has determined to provide a program—called the CEIP—in which states may choose to participate.

The CEIP is designed to incentivize investment in certain RE and demand-side EE projects that commence construction, in the case of RE, or commence construction, in the case of demand-side EE, following the submission of a final state plan to the EPA, or after September 6, 2018, for states that choose not to submit a final state plan by that date, and that generate MWh (RE) or reduce end-use energy demand (EE) during 2020 and/or 2021. State participation in the program is optional.

Under the CEIP, a state may set aside allowances from the CO_2 emission budget it establishes for the interim plan performance period or may generate early action ERCs (ERCs are discussed in more detail in section VIII.K.2), and allocate these allowances or ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. For each early action allowance or ERC a state allocates to such projects, the EPA will provide the state with an appropriate number of matching allowances or ERCs for the state to allocate to the project. The EPA will match state-issued early action ERCs and allowances up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions.

For a state to be eligible for a matching award of allowances or ERCs from the EPA, it must demonstrate that it will award allowances or ERCs only to "eligible" projects. These are projects that:

- Are located in or benefit a state that has submitted a final state plan that includes requirements establishing its participation in the CEIP;
- Are implemented following the submission of a final state plan to the EPA, or after September 6, 2018, for a state that chooses not to submit a complete state plan by that date;
- For RE: Generate metered MWh from any type of wind or solar resources;
- For EE: Result in quantified and verified electricity savings (MWh) through demand-side EE implemented in low-income communities; and
- Generate or save MWh in 2020 and/ or 2021.

The following provisions outline how a state may award early action ERCs and allowances to eligible projects, and how the EPA will provide matching ERCs or allowances to states.

- For RE projects that generate metered MWh from any type of wind or solar resources: For every two MWh generated, the project will receive one early action ERC (or the equivalent number of allowances) from the state, and the EPA will provide one matching ERC (or the equivalent number of allowances) to the state to award to the project.

- For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs (or the equivalent number of allowances) from the state, and the EPA will provide two matching ERCs (or the equivalent number of allowances) to the state to award to the project.

Early action allowances or ERCs awarded by the state, and matching allowances or ERCs awarded by the EPA pursuant to the CEIP, may be used for compliance by an affected EGU with its emission standards and are fully transferrable prior to such use.

The EPA discusses the CEIP in the proposed federal plan rule and will address design and implementation details of the CEIP in a subsequent action. Prior to doing so, the EPA will engage with states, utilities and other stakeholders to gather information regarding their interests and priorities with regard to implementation of the CEIP.

(8) *Provisions for electric system reliability*.

A number of commenters stressed the importance of final guidelines that addressed the need to ensure that EGUs could meet their emission reduction requirements without being compelled to take actions that would undermine electric system reliability. As noted above, the EPA has consulted extensively with federal, regional and state energy agencies, utilities and many others about reliability concerns and ways to address them. The final guidelines support electric system reliability in a number of ways, some inherent in the improvements made in the program's design and some through specific provisions we have included in the final rule. Most important are the two key changes we made to the interim goal: Establishing 2022, instead of 2020, as the period for mandatory emission reductions begin and phasing in, over the 8-year period, emission performance rates such that the level of stringency of the emission performance rates in 2022–2024 is significantly less than that for the years 2028 and 2029. Since states and utilities need only to meet their interim goal "on average" over the 8-year period, these changes provide them with a great deal of latitude in determining for themselves their emission reduction trajectory—and they have additional time to do so. As a result, the final guidelines provide the ingredients that commenters, reliability entities and expert agencies told the EPA were essential to ensuring electric system reliability: Time and flexibility sufficient to allow for planning, implementation and the integration of actions needed to address reliability while achieving the required emissions reductions.

In addition, the final guidelines add a requirement, based on substantial input from experts in the energy field, for states to demonstrate that they have considered electric system reliability in developing their state plans. The final rule also offers additional opportunities that support electric system reliability, including opportunities for trading within and between states. The final guidelines also make clear that states can adjust their plans in the event that reliability challenges arise that need to be remedied by amending the state plan. In addition, the final rule includes a reliability safety valve to address situations where, because of an unanticipated catastrophic event, there is a conflict between the requirements imposed on an affected unit and the maintenance of reliability.

(9) *Approaches for addressing employment concerns*.

Some commenters brought to our attention the concerns of workers, their families and communities, particularly in coal-producing regions and states, that the ongoing shift toward lower-carbon electricity generation that the final rule reflects will cause harm to communities that are dependent on coal. Others had concerns about whether new jobs created as a result of actions taken pursuant to the final rule will allow for overall economic development. In the final rule, the EPA encourages states, in designing their state plans, to consider the effects of their plans on employment and overall economic development to assure that the opportunities for economic growth and jobs that the plans offer are manifest. We also identify federal programs, including the multi-agency Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initiative.[15] The POWER Initiative is competitively awarding planning assistance and implementation grants with funding from the Department of Commerce, Department of Labor (DOL), Small Business Administration, and the Appalachian Regional Commission,[16] whose mission is to assist communities affected by changes in the coal industry and the utility power sector.

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[15] *http://www.eda.gov/power/*.

[16] *https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz*.

(10) *Community and environmental justice considerations*.

Many community leaders, environmental justice advocates, faith-based organizations and others commented that the benefits of this rule must be shared broadly across society and that undue burdens should not be imposed on low-income ratepayers. We agree. The federal government is taking significant steps to help low-income families and individuals gain access to RE and demand-side EE through new initiatives involving, for example, increasing solar energy systems in federally subsidized homes and supporting solar systems for others with low incomes. The final rule ensures that bill-lowering measures such as demand-side EE continue to be a major compliance option. The CEIP will encourage early investment in these types of projects as well. In addition to carbon reduction benefits, we expect significant near- and long-term public health benefits in communities as conventional air pollutants are reduced along with GHGs. However, some stakeholders expressed concerns about the possibility of localized increases in emissions from some power plants as the utility industry complies with state plans, in particular in communities already disproportionately affected by air pollution. This rule sets expectations for states to engage with vulnerable communities as they develop their plans, so that impacts on these communities are considered as plans are designed. The EPA also encourages states to engage with workers in the utility power and related sectors, as well as their worker representatives, so that impacts on their communities may be considered. The EPA commits, once implementation is under way, to assess the impacts of this rule. Likewise, we encourage states to evaluate the effects of their plans to ensure that there are no disproportionate adverse impacts on their communities.

5. Additional Context for This Final Rule

a. *Climate change impacts*. This final rule is an important step in an essential series of long-term actions that are achieving and must continue to achieve the GHG emission reductions needed to address the serious threat of climate change, and constitutes a major commitment—and international leadership-by-doing—on the part of the U.S., one of the world's largest GHG emitters. GHG pollution threatens the American public by leading to damaging and long-lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO_2 is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions[17] and 82 percent of U.S. GHG emissions.[18] The May 2014 report of the National Climate Assessment[19] concluded that climate change impacts

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[17] Intergovernmental Panel on Climate Change (IPCC) report, "Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change," 2007. Available at *http://epa.gov/climatechange/ghgemissions/global.html*.

[18] 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. Available at *http://epa.gov/climatechange/ghgemissions/usinventoryrepoft.html*.

[19] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate

are already manifesting themselves and imposing losses and costs. The report documents increases in extreme weather and climate events in recent decades, with resulting damage and disruption to human well-being, infrastructure, ecosystems, and agriculture, and projects continued increases in impacts across a wide range of communities, sectors, and ecosystems. New scientific assessments since 2009, when the EPA determined that GHGs pose a threat to human health and the environment (the "Endangerment Finding"), highlight the urgency of addressing the rising concentration of CO_2 in the atmosphere. Certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related effects. Recent studies also find that certain communities, including low-income communities and some communities of color (more specifically, populations defined jointly by ethnic/racial characteristics and geographic location), are disproportionately affected by certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—which are associated with increased deaths, illnesses, and economic challenges. Studies also find that climate change poses particular threats to the health, well-being, and ways of life of indigenous peoples in the U.S.

b. *The utility power sector*. One of the strategies of the President's Climate Action Plan is to reduce CO_2

Assessment, May 2014. Available at *http://nca2014.globalchange.gov/*.

emissions from power plants.[20] This is because fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO_2. Among stationary sources in the U.S. and among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters of GHGs. To accomplish the goal of reducing CO_2 emissions from power plants, President Obama issued a Presidential Memorandum[21] that recognized the importance of significant and prompt action. The Memorandum directed the EPA to complete carbon pollution standards, regulations or guidelines, as appropriate, for new, modified, reconstructed and existing power plants, and in doing so to build on state leadership in moving toward a cleaner power sector. In this action and the concurrent CAA section 111(b) rule, the EPA is finalizing regulations to reduce GHG emissions from fossil fuel-fired EGUs. This CAA section 111(d) action builds on actions states and utilities are already taking to move toward cleaner generation of electric power.

The utility power sector is unlike other industrial sectors. In other sectors, sources effectively operate independently and on a local-site scale, with control of their physical operations resting in the hands of their respective owners and operators. Pollution control standards, which focus on each source in a non-utility industrial source category, have reflected the

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[20] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

[21] 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.*

standalone character of individual source investment decision-making and operations.

In stark contrast, the utility power sector comprises a unique system of electricity resources, including the EGUs affected under these guidelines, that operate in a complex and interconnected grid where electricity generally flows freely (*e.g.*, portions of the system cannot be easily isolated through the use of switches or valves as can be done in other networked systems like trains and pipeline systems). That grid is physically interconnected and operated on an integrated basis across large regions. In this interconnected system, system operators, whose decisions, protocols, and actions, to a significant extent, dictate the operations of individual EGUs and large ensembles of EGUs, must reliably balance supply and demand using available generation and demand-side resources, including EE, demand response and a wide range of low- and zero-emitting sources. These resources are managed to meet the system needs in a reliable and efficient manner. Each aspect of this interconnected system is highly regulated and coordinated, with supply and demand constantly being balanced to meet system needs. Each step of the process from the electric generator to the end user is highly regulated by multiple entities working in coordination and considering overall system reliability. For example, in an independent system operator (ISO) or regional transmission organization (RTO) with a centralized, organized capacity market, electric generators are paid to be available to run when needed, must bid into energy markets, must respond to dispatch instructions, and must have permission to schedule maintenance. The ISO/RTO dispatches resources in a way that maintains electric system reliability.

The approach we take in the final guidelines—both in the way we defined the BSER and established the resulting emission performance rates, and in the ranges of options we created for states and affected EGUs—is consistent with, and in some ways mirrors, the interconnected, interdependent and highly regulated nature of the utility power sector, the daily operation of affected EGUs within this framework, and the critical role of utilities in providing reliable, affordable electricity at all times and in all places within this complex, regulated system. Thus, not only do these guidelines put a premium on providing as much flexibility and latitude as possible for states and utilities, they also recognize that a given EGU's operations are determined by the availability and use of other generation resources to which it is physically connected and by the collective operating regime that integrates that individual EGU's activity with other resources across the grid.

In this integrated system, numerous entities have both the capability and the responsibility to maintain a reliable electric system. FERC, DOE, state public utility commissions, ISOs, RTOs, other planning authorities, and the North American Electric Reliability Corporation (NERC), all contribute to ensuring the reliability of the electric system in the U.S. Critical to this function are dispatch tools, applied primarily by RTOs, ISOs, and balancing authorities, that operate such that actions taken or costs incurred at one source directly affect or cause actions to occur at other sources. Generation, outages, and transmission changes in one part of the synchronous grid can affect the entire interconnected grid.[22] The interconnection is such that "[i]f a generator is lost in New York City, its effect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans."[23] The U.S. Supreme Court has explicitly recognized the interconnected nature of the electricity grid.[24]

The uniqueness of the utility power sector inevitably affects the way in which environmental regulations are designed. When the EPA promulgates

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[22] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).

[23] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 160 (2d ed. 2010).

[24] *Federal Power Comm'n* v. *Florida Power & Light Co.*, 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, "'If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.'") (citation omitted). *See also New York* v. *FERC*, 535 U.S. 1, at 7–8 (2002) (stating that "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.") (citation omitted). In *Federal Power Comm'n* v. *Southern California Edison Co.*, 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, "'federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'" *Id.* at 210, *quoting Connecticut Light & Power Co.* v. *Federal Power Commission*, 324 U.S. 515, 529 (1945) (emphasis omitted).

environmental regulations that affect the utility power sector, as we have done numerous times over the past four decades, we do so with the awareness of the importance of the efficient and continuous, uninterrupted operation of the interconnected electricity system in which EGUs participate. We also keep in mind the unique product that this interconnected system provides—electricity services—and the critical role of this sector to the U.S. economy and to the fundamental well-being of all Americans.

In the context of environmental regulation, Congress, the EPA and the states all have recognized—as we do in these final guidelines—that electricity production takes place, at least to some extent, interchangeably between and among multiple generation facilities and different types of generation. This is evidenced in the enactment or promulgation of pollution reduction programs, such as Title IV of the CAA, the NO_X state implementation plan (SIP) Call, the Cross-State Air Pollution Rule (CSAPR), and the Regional Greenhouse Gas Initiative (RGGI). As these actions show, both Congress and the EPA have consistently tailored legislation and regulations affecting the utility power sector to its unique characteristics. For example, in Title IV of the Clean Air Act Amendments of 1990, Congress established a pollution reduction program specifically for fossil fuel-fired EGUs and designed the SO_2 portion of that program with express recognition of the sector's ability to shift generation among various EGUs, which enabled pollution reduction by increasing reliance on natural gas-fired units and RE. Similarly, in the NO_X SIP Call, the Clean Air Interstate Rule (CAIR), and CSAPR, the EPA established pollution reduction programs focused on fossil fuel-fired EGUs and designed those programs with express recognition of the sector's ability to shift generation among various EGUs. In this action, we continue that approach. Both the subcategory-specific emission performance rates, and the pathways offered to achieve them, reflect and are tailored to the unique characteristics of the utility power sector.

The way that power is produced, distributed and used in the U.S. is already changing as a result of advancements in innovative power sector technologies and in the availability and cost of low-carbon fuel, RE and demand-side EE technologies, as well as economic conditions. These changes are taking place at a time when the average age of the coal-fired generating fleet is approaching that at which utilities and states undertake significant new investments to address aging assets. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. Therefore, even in the absence of additional environmental regulation, states and utilities can be expected to be, and already are, making plans for and investing in the next generation of power production, simply because of the need to take account of the age of current assets and infrastructure. Historically, the industry has invested about $100 billion a year in capital improvements. These guidelines will help ensure that, as those necessary investments are being made, they are integrated with the need to address GHG pollution from the sector.

At the same time, owners/operators of affected EGUs are already pursuing the types of measures contemplated in this rule. Out of 404 entities identified as owners or operators of affected EGUs, representing ownership of 82 percent of the total capacity of the affected EGUs, 178 already own RE generating capacity in addition to fossil fuel-fired generating capacity. In fact, these entities already own aggregate amounts of RE generating capacity equal to 25 percent of the aggregate amounts of their affected EGU capacity.[25] In addition, funding for utility EE programs has been growing rapidly, increasing from $1.6 billion in 2006 to $6.3 billion in 2013.

The final guidelines are based on, and reinforce, the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines will ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in the utility power sector. This final rule provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs, and minimizes additional requirements for existing programs where possible. It also allows states to pursue policies to reduce carbon pollution that: (1) Continue to rely on a diverse set of energy resources; (2) ensure electric system reliability; (3) provide affordable electricity; (4) recognize investments that states and power companies are already making; and (5) tailor plans to meet their respective energy, environmental and economic needs and goals, and those of their local communities. Thus,

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[25] SNL Energy. Data used with permission. Accessed on June 9, 2015.

the final guidelines will achieve meaningful CO_2 emission reductions while maintaining the reliability and affordability of electricity in the U.S.

6. Projected National-Level Emission Reductions

Under the final guidelines, the EPA projects annual CO_2 reductions of 22 to 23 percent below 2005 levels in 2020, 28 to 29 percent below 2005 levels in 2025, and 32 percent below 2005 levels in 2030. These guidelines will also result in important reductions in emissions of criteria air pollutants, including SO_2, NO_X, and directly-emitted fine particulate matter ($PM_{2.5}$). A thorough discussion of the EPA's analysis is presented in Section XI.A of this preamble and in Chapter 3 of the Regulatory Impact Analysis (RIA) included in the docket for this rulemaking.

7. Costs and Benefits

Actions taken to comply with the final guidelines will reduce emissions of CO_2 and other air pollutants, including SO_2, NO_X, and directly emitted $PM_{2.5}$ from the utility power sector. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates. The illustrative costs and benefits are based upon compliance approaches that reflect a range of measures consisting of improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and increasing levels of end-use EE.

Because of the range of choices available to states and the lack of *a priori* knowledge about the specific choices states will make in response to the final goals, the RIA for this final action presents two scenarios designed to achieve these goals, which we term the "rate-based" illustrative plan approach and the "mass-based" illustrative plan approach.

In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based 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 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 22 of this preamble.

The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side EE program and participant costs as well as monitoring, reporting and recordkeeping costs. In 2020, total compliance costs of the final guidelines are approximately \$2.5 billion (2011\$) under the rate-based approach and \$1.4 billion (2011\$) under the mass-based approach. In 2025, total compliance costs of the final guidelines are approximately \$1.0 billion (2011\$) under the rate-based approach and \$3.0 billion (2011\$) under the mass-based approach. In 2030, total compliance costs of the final guidelines are approximately \$8.4 billion (2011\$) under the rate-based approach and \$5.1 billion (2011\$) under the mass-based approach.

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\$) using a 3 percent discount rate (model average) under the rate-based approach and from $3.9 billion to $6.7 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2025, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $16 billion to $26 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach. In 2030, the quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) using a 3 percent discount rate (model average) under the rate-based approach and from $26 billion to $43 billion (2011$) using a 3 percent discount rate (model average) under the mass-based approach.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025, AND 2030[a] UNDER THE RATE-BASED ILLUSTRATIVE PLAN APPROACH
[Billions of 2011$]

Rate-based approach, 2020		
	3% Discount rate	7% Discount rate
Climate benefits[b]	$2.8	
Air pollution health co-benefits[c]	$0.70 to $1.8	$0.64 to $1.7.
Total Compliance Costs[d]	$2.5	$2.5.
Net Monetized Benefits[e]	$1.0 to $2.1	$1.0 to $2.0.
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.	

Rate-based approach, 2025		
Climate benefits[b]	$10	
Air pollution health co-benefits[c]	$7.4 to $18	$6.7 to $16.
Total Compliance Costs[d]	$1.0	$1.0.
Net Monetized Benefits[e]	$17 to $27	$16 to $25.
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.	

Rate-based approach, 2030		
Climate benefits[b]	$20	
Air pollution health co-benefits[c]	$14 to $34	$13 to $31.
Total Compliance Costs[d]	$8.4	$8.4.
Net Monetized Benefits[e]	$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 SCC 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 SCFCO_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 directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in pre-mature 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] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side 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 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE FINAL GUIDELINES IN 2020, 2025 AND 2030 [a] UNDER THE MASS-BASED ILLUSTRATIVE PLAN APPROACH
[Billions of 2011$]

Mass-based approach, 2020		
	3% Discount rate	7% Discount rate
Climate benefits[b]	$3.3	
Air pollution health co-benefits[c]	$2.0 to $4.8	$1.8 to $4.4.
Total Compliance Costs[d]	$1.4	$1.4.
Net Monetized Benefits[e]	$3.9 to $6.7	$3.7 to $6.3.
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.	

Mass-based approach, 2025		
Climate benefits[b]	$12	
Air pollution health co-benefits[c]	$7.1 to $17	$6.5 to $16.
Total Compliance Costs[d]	$3.0	$3.0.
Net Monetized Benefits[e]	$16 to $26	$15 to $24.
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.	
Mass-based approach, 2030		
Climate benefits[b]	$20	
Air pollution health co-benefits[c]	$12 to $28	$11 to $26.
Total Compliance Costs[d]	$5.1	$5.1.
Net Monetized Benefits[e]	$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 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 directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in pre-mature 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] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the final guidelines and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand-side 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. The unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.*, nitrous oxide and methane)[26] and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (*e.g.*, mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

We project employment gains and losses relative to base case for different types of labor, including construction, plant operation and maintenance, coal and natural gas production, and demand-side EE. In 2030, we project a net decrease in job-years of about 31,000 under the rate-based approach and 34,000 under the mass-based approach[27] for construction, plant operation and maintenance, and coal and natural gas and a gain of 52,000 to 83,000 jobs in the demand-side EE sector under either approach. Actual employment impacts will depend upon measures

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[26] Although CO_2 is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. For more detail about power sector emissions, see RIA Chapter 2 and the U.S. Greenhouse Gas Reporting Program's power sector summary, *http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html*.

[27] A job-year is not an individual job; rather, a job-year is the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2025 may represent 20 full-time jobs or 40 half-time jobs.

taken by states in their state plans and the specific actions sources take to comply.

Based upon the foregoing, it is clear that the monetized benefits of this rule are substantial and far outweigh the costs.

B. Organization and Approach for This Rule

This final rule establishes the EPA's emission guidelines for states to follow in developing plans to reduce CO_2 emissions from the utility power sector. Section II of this preamble provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the CAA section 111(d) requirements, EPA actions prior to this final action, outreach and consultations, and the number and extent of comments received. In section III of the preamble, we present a summary of the rule requirements and the legal basis for these. Section IV explains the EPA authority to regulate CO_2 and EGUs, identifies affected EGUs, and describes the proposed treatment of source categories. Section V describes the agency's determination of the BSER using three building blocks and our key considerations in making the determination. Section VI provides the subcategory-specific emission performance rates, and section VII provides equivalent statewide rate-based and mass-based goals. Section VIII then describes state plan approaches and the requirements, and flexibilities, for state plans, followed by section IX, in which considerations for communities are described. Interactions between this final rule and other EPA programs and rules are discussed in section X. Impacts of the proposed action are then described in section XI, followed by a discussion of statutory and executive order reviews in section XII and the statutory authority for this action in section XIII.

We note that this rulemaking is being promulgated concurrently with two related actions in this issue of the **Federal Register**: The final NSPS for CO_2 emissions from newly constructed, modified, and reconstructed EGUs, which is being promulgated under CAA section 111(b), and the proposed federal plan and model rules. These rulemakings have their own rulemaking dockets.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs, the challenges associated with controlling carbon dioxide emissions, the uniqueness of the utility power sector, and recent and continuing trends and transitions in the utility power sector. In addition, we briefly describe CAA regulations for power plants, provide highlights of Congressional awareness of climate change and international agreements and actions, and summarize statutory and regulatory requirements relevant to this rulemaking. In addition, we provide background information on the EPA's June 18, 2014 Clean Power Plan proposal, the November 4, 2014 supplemental proposal, and other actions associated with this rulemaking,[28] followed by information on stakeholder

[28] The EPA also published in the **Federal Register** a notice of data availability (79 FR 64543; November 8, 2014) and a notice on the translation of emission rate-based CO_2 goals to mass-based equivalents (79 FR 67406; November 13, 2014).

outreach and consultations and the comments that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts From GHG Emissions

According to the National Research Council, "Emissions of CO_2 from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because CO_2 in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia."[29]

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[30] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the U.S. We summarize these adverse effects on public health and welfare briefly here.

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[29] National Research Council, Climate Stabilization Targets, p.3.

[30] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 FR 66496 (Dec. 15, 2009) ("Endangerment Finding").

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flooding damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand. Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments and Observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013–2014 Fifth Assessment Report (AR5), the USGCRP's 2014 National Climate Assessment, *Climate Change Impacts in the United States* (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future, 2012 Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in Section VIII.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, the IPCC, and the NRC of the National Academies to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the U.S. will be impacted by "increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks." The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the U.S. through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.*, permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their "strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines." [31] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The

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[31] 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, Cambridge, p. 1581. *https://www.ipcc.ch/report/ar5/wg2/*.

IPCC finds that additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment Understanding Earth's Deep Past projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[32] In fact, that assessment stated that "the magnitude and rate of the present GHG increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history."[33] Because of

[32] National Research Council, Understanding Earth's Deep Past, p. 1.

[33] Id., p.138.

these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, "As Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur." The NRC Abrupt Impacts report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3–4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of an irreversible impact that is expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that global temperatures by the end of the century will likely be 2.6 °C to 4.8 °C (4.7 to 8.6 °F) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data was already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of carbon dioxide and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland Ice sheets. The NRC Sea Level Rise assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC National Security Implications assessment suggests that "the Department of the Navy should expect roughly 0.4 to 2 meters [1.3 to 6.6 feet] global average sea-level rise by 2100," [34] and the NRC Climate Stabilization Targets assessment states that an increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from the global total depending on various factors: The east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that "five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level," and the NCA3 finds that "[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges." [35] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations

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[34] NRC, 2011: *National Security implications of Climate Change for U.S. Naval Forces*. The National Academies Press, p. 28.

[35] 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, p. 9.

have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: According to the NCA, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the U.S. and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the U.S. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, "[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied." [36] The IPCC AR5 notes, "Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in

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[36] 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, p. 17.

crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity."[37]

Carbon dioxide in particular has unique impacts on ocean ecosystems. The NRC Climate Stabilization Targets assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC Understanding Earth's Deep Past assessment notes four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC Abrupt Impacts assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC Ocean Acidification assessment finds that "[t]he chemistry of

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[37] 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, p. 796. *https://www.ipcc.ch/report/ar5/wg2/*.

the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years."[38] The assessment notes that the full range of consequences is still unknown, but the risks "threaten coral reefs, fisheries, protected species, and other natural resources of value to society."[39]

Events outside the U.S., as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events "will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response." The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the U.S. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet

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[38] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean*. The National Academies Press, p. 5.

[39] Ibid.

warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 degrees F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 mm. Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million, far above preindustrial concentrations of about 280 parts per million.[40] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years.[41] Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979–2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[42] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest

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[40] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt*.

[41] *http://www.esrl.noaa.gov/gmd/ccgg/trends/*.

[42] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

years on record have occurred since 2002.[43] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons "why it is imprudent to delay actions that at least begin the process of substantially reducing emissions."[44] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.

- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.

- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

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[43] *http://www.ncdc.noaa.gov/sotc/global/2014/13*.

[44] NRC, 2011: *America's Climate Choices*, The National Academies Press.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in 8 regions of the U.S., noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s followed by a cool period and temperatures then increased again from 1970 to the present by an average of 2 °F. There have been increasing numbers of days above 95 °F and nights above 75 °F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95 °F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 are generally smaller than for other regions of the U.S., projected warming for interior states of the region are larger than coastal regions by 1 °F to 2 °F. Projections further suggest that globally there will be fewer tropical storms, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3 °F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3 °F to 9.7 °F by the end of the century (depending on future global GHG emissions), with the greatest warming expected during the summer.

Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the U.S. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began.

Climate change impacts are harming the health, safety and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state, however warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate-change induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and backup of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010 the rate of warming was three times faster than from 1900 through 2010.

Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (*e.g.*, heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6 °F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3 °F by 2055 and 4.7 °F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions From Fossil Fuel-Fired EGUs[45]

Fossil fuel-fired electric utility generating units (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[46] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program[47] (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.

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[45] The emission data presented in this section of the preamble (Section II.B) are in metric tons, in keeping with reporting requirements for the GHGRP and the U.S. GHG Inventory. Note that the mass-based state goals presented in section VII of this preamble, and discussed elsewhere in this preamble, are presented in short tons.

[46] "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://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

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

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 below, which presents total U.S. anthropogenic emissions and sinks[48] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR
[Million metric tons carbon dioxide equivalent ($MMT\ CO_2$ Eq.)][49]

Sector	1990	2005	2013
Energy[50]	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

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

[49] From Table ES-4 of "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013", Report EPA 430-R-15-004, U.S. Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

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

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.[51] 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.[52] Table 4 below 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][53]

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	1,938.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

[51] 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://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[52] 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. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[53] 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://epa.gov/climatechange/ghgemissions/usinventoryreport html.*

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its Greenhouse Gas Reporting Program (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 below 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, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported 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][54]

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

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

C. Challenges in Controlling Carbon Dioxide Emissions

Carbon dioxide is a unique air pollutant and controlling it presents unique challenges. CO_2 is emitted in enormous quantities, and those quantities, coupled with the fact that CO_2 is relatively unreactive, make it much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant. Measures that may be used to limit CO_2 emissions would include efficiency improvements, which have thermodynamic limitations and carbon capture and sequestration (CCS), which is energy resource intensive.

Unlike other air pollutants which are results of trace impurities in the fuel, products of incomplete or inefficient combustion, or combustion byproducts, CO_2 is an inherent product of clean, efficient combustion of fossil fuels, and therefore is an unavoidable product generated in enormous quantities, far greater than any other air pollutant.[55] In fact, CO_2 is emitted in far greater quantities than all other air pollutants *combined*. Total emissions of all non-GHG air

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[55] Lackner et al., "Comparative Impacts of Fossil Fuels and Alternative Energy Sources", Issues in Environmental Science and Technology (2010).

pollutants in the U.S., from all sources, in 2013, were 121 million metric tons.[56] [57]

Pollutant	2013 tons (million short tons)	Reference
CO.........	69.758	Trends file (*http://www.epa.gov/ttnchie1/trends/*).
NO_X.......	13.072	"
PM_{10}......	20.651	"
SO_2........	5.098	"
VOC	17.471	"
NH_3.......	4.221	"

[56] This includes NAAQS and HAPs, based on the following table: (see table above).

It should be noted that $PM_{2.5}$ is included in the amounts for PM_{10}. Lead, another NAAQS pollutant, is emitted in the amounts of approximately 1,000 tons per year, and, in light of that relatively small quantity, was excluded from this analysis. Ammonia (NH_3) is included because it is a precursor to $PM_{2.5}$ secondary formation. Note that one short ton is equivalent to 0.907185 metric ton.

[57] In addition, emissions of non-CO_2 GHGs totaled 1.168 billion metric tons of carbon-dioxide equivalents (CO_2e) in 2013. *See* Table ES-2, Executive Summary, 1990–2013 Inventory of U.S. Greenhouse Gas Emissions and Sinks, *http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Chapter-Executive-Summary.pdf*. This includes emissions of methane, nitrous oxide, and fluorinated GHGs (hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride). In the total, the emissions of each non-CO_2 GHG have been translated from metric tons of that gas into metric tons of CO_2e by multiplying the metric tons of the gas by the global warming potential (GWP) of the gas. (The GWP of a gas is a measure of the ability of one kilogram of that gas to trap heat in earth's atmosphere compared to one kilogram of CO_2.)

HAPS....	3.641	2011 NEI version 2 (*http://www.epa.gov/ttn/chief/net/2011inventory.html*).
Total...	133.912	

As noted above, total emissions of CO_2 from coal-fired power plants alone—the largest stationary source emitter—were 1.575 billion metric tons in that year,[58] and total emissions of CO_2 from all sources were 5.5 billion metric tons.[59] [60] Carbon makes up the majority of the mass of coal and other fossil fuels, and for every ton of carbon burned, more than 3 tons of CO_2 is produced.[61] In addition, unlike many of the other air pollutants that react with sunlight or chemicals in the atmosphere, or are rained out or deposited on

[58] 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://epa.gov/climatechange/ghgemissions/usinventoryreport.html*.

[59] U.S. EPA, *Greenhouse Gas Inventory Data Explorer*, *http://www.epa.gov/climatechange/ghgemissions/inventoryexplorer/#allsectors/allgas/gas/current*.

[60] As another point of comparison, except for carbon dioxide, SO_2 and NO_X are the largest air pollutant emissions from coal-fired power plants. Over the past decade, U.S. power plants have emitted more than 200 times as much CO_2 as they have emitted SO_2 and NO_X. *See* de Gouw et al., "Reduced emissions of CO_2, NO_X, and SO_2 from U.S. power plants owing to switch from coal to natural gas with combined cycle technology," Earth's Future (2014).

[61] Each atom of carbon in the fuel combines with 2 atoms of oxygen in the air.

surfaces, CO_2 is relatively unreactive and difficult to remove directly from the atmosphere.[62] [63]

CO_2's huge quantities and lack of reactivity make it challenging to remove from the smokestack. Retrofitted equipment is required to capture the CO_2 before transporting it to a storage site. However, the scale of infrastructure required to directly mitigate CO_2 emissions from existing EGUs through CCS can be quite large and difficult to integrate into the existing fossil fuel infrastructure. These CCS techniques are discussed in more depth elsewhere in the preamble for this rule and for the section 111(b) rule for new sources that accompanies this rule.

The properties of CO_2 can be contrasted with those of a number of other pollutants which have more accessible mitigation options. For example, the NAAQS pollutants—which generally are emitted in the largest quantities of any of the other air pollutants, except for CO_2—each have more accessible mitigation options. Sulfur dioxide (SO_2) is the result of a contaminant in the fuel, and, as a result, it can be reduced by using low-sulfur coal or by using flue-gas desulfurization (FGD) technologies. Emissions of NO_X can be mitigated relatively easily using combustion control techniques (*e.g.*, low-NO_X burners) and by using downstream controls such as selective catalytic

[62] Seinfeld J. and Pandis S., Atmospheric Chemistry and Physics: From Air Pollution to Climate Change (1998).

[63] The fact that CO_2 is unreactive means that it is primarily removed from the atmosphere by dissolving in oceans or by being converted into biomass by plants. Herzog, H., "Scaling up carbon dioxide capture and storage: From megatons to gigatons", Energy Economics (2011).

reduction (SCR) and selective non-catalytic reduction (SNCR) technologies. PM can be effectively mitigated using fabric filters, PM scrubbers, or electrostatic precipitators. Lead is part of particulate matter emissions and is controlled through the same devices. Carbon monoxide and VOCs are the products of incomplete combustion and can therefore be abated by more efficient combustion conditions, and can also be destroyed in the smokestack by the use of oxidation catalysts which complete the combustion process. Many air toxics are VOCs, such as polyaromatic hydrocarbons, and therefore can be abated in the same ways just described. But in every case, these pollutants can be controlled at the source much more readily than CO_2 primarily because of the comparatively lower quantities that are produced, and also due to other attributes such as relatively greater reactivity and solubility.

D. The Utility Power Sector

1. A Brief History

The modern American electricity system is one of the greatest engineering achievements of the past 100 years. Since the invention of the incandescent light bulb in the 1870s,[64] electricity has become one of the major foundations for modern American life. Beginning with the first power station in New York City in 1882, each power station initially served a discrete set of consumers, resulting in small and

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[64] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 1 (2011), *available at http://www.raponline.org/document/download/id/645*.

localized electricity systems.[65] During the early 1900s, smaller systems consolidated, allowing generation resources to be shared over larger areas. Interconnecting systems have reduced generation investment costs and improved reliability.[66] Local and state governments initially regulated these growing electricity systems with federal regulation coming later in response to public concerns about rising electricity costs.[67]

Initially, states had broad authority to regulate public utilities, but gradually federal regulation increased. In 1920, Congress passed the Federal Water Power Act, creating the Federal Power Commission (FPC) and providing for the licensing of hydroelectric facilities on U.S. government lands and navigable waters of the U.S.[68] During this time period, the U.S. Supreme Court found that state authority to

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[65] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 2–4 (2d ed. 2010).

[66] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 5–6 (2d ed. 2010). Investment in electric generation is extremely capital intensive, with generation potentially accounting for 65 percent of customer costs. If these costs can be spread to more customers, then this can reduce the amount that each individual customer pays. Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

[67] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015).

[68] The FPC became an independent Commission in 1930. *United States Government Manual 1945: First Edition*, at 486, *available at http://www.ibiblio.org/hyperwar/ATO/USGM/FPC.html*.

regulate public utilities is limited, holding that the Commerce Clause does not allow state regulation to directly burden interstate commerce.[69] For example, in *Public Utilities Commission of Rhode Island* v. *Attleboro Steam & Electric Company*, Rhode Island sought to regulate the electricity rates that a Rhode Island generator was charging to a company in Massachusetts that resold the electricity to Attleboro, Massachusetts.[70] The Supreme Court found that Rhode Island's regulation was impermissible because it imposed a "direct burden upon interstate commerce."[71] The Supreme Court held that this kind of interstate transaction was not subject to state regulation. However, because Congress had not yet passed legislation to make these types of transactions subject to federal regulation, this became known as the "*Attleboro* gap" in regulation. In 1935, Congress passed the Federal Power Act (FPA), giving the FPC jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[72] Under FPA section 205, the FPC was tasked with ensuring that rates for jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.[73] FPA section 206 authorized the FPC to

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[69] *New York* v. *Federal Energy Regulatory Commission*, 535 U.S. 1, 5 (2002) (citation omitted).

[70] *Public Utils. Comm'n of Rhode Island* v. *Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).*

[71] *Public Utils. Comm'n of Rhode Island* v. *Attleboro Steam & Elec. Co., 273 U.S. 83, 89 (1927).*

[72] 16 U.S.C. 824(b)(1).

[73] 16 U.S.C. 824d.

determine, after a hearing upon its own motion or in response to a complaint filed at the Commission, whether jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential.[74] In 1938, Congress passed the Natural Gas Act (NGA), giving the FPC jurisdiction over the transmission or sale of natural gas in interstate commerce.[75] The NGA also gave the FPC the jurisdiction to "grant certificates allowing construction and operation of facilities used in interstate gas transmission and authorizing the provision of services."[76] In 1977, the FPC became FERC after Congress passed the Department of Energy Organization Act.

By the 1930s, regulated electric utilities that provided the major components of the electrical system—generation, transmission, and distribution—were common.[77] These regulated monopolies are referred to as vertically-integrated utilities.

As utilities built larger and larger electric generation plants, the cost per unit to generate electricity decreased.[78] However, these larger plants

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[74] 16 U.S.C. 824e.

[75] Energy Information Administration, *Natural Gas Act of 1938*, *available at http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html*.

[76] Energy Information Administration, *Natural Gas Act of 1938*, *available at http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1938.html*.

[77] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015).

[78] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

were extremely capital intensive for any one company to fund.[79] Some neighboring utilities solved this issue by agreeing to share electricity reserves when needed.[80] These utilities began building larger transmission lines to deliver power in times when large generators experienced outages.[81] Eventually, some utilities that were in reserve sharing agreements formed electric power pools to balance electric load over a larger area. Participating utilities gave control over scheduling and dispatch of their electric generation units to a system operator.[82] Some power pools evolved into today's RTOs and ISOs.

In the past, electric utilities generally operated as state regulated monopolies, supplying end-use customers with generation, distribution, and transmission service.[83] However, the ability of electric utilities to operate as natural monopolies came with

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[79] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

[80] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

[81] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 38 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

[82] Shively, B, Ferrare, J, *Understanding Today's Electricity Business*, Enerdynamics, at 94 (2012).

[83] Maryland Department of Natural Resources, *Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources*, at 2–5 (2006), *available at http://esm.versar.com/pprp/ceir13/toc.htm*.

consumer protection safeguards.[84] "In exchange for a franchised, monopoly service area, utilities accept an obligation to serve—meaning there must be adequate supply to meet customers' needs regardless of the cost."[85] Under this obligation to serve, the utility agreed to provide service to any customer located within its service jurisdiction.

On both a federal and state level, competition has entered the electricity sector to varying degrees in the last few decades.[86] In the early 1990s, some states began to consider allowing competition to enter retail electric service.[87] Federal and state efforts to allow

[84] Pacific Power, *Utility Regulation*, at 1, *available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf*.

[85] Pacific Power, *Utility Regulation*, at 1, *available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Newsroom/Media_Resources/Regulation.PP.08.pdf*.

[86] For example, in 1978, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which allowed non-utility owned power plants to sell electricity. Burn, An Energy Journal, *The Electricity Grid: A History*, *available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015). PURPA, the Energy Policy Act of 1992 (EPAct 1992), and the Energy Policy Act of 2005 (EPAct 2005) "promoted competition by lowering entry barriers and increasing transmission access." The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, at 2, *available at http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf* (last visited Mar. 20, 2015).

[87] The Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, at 2, *available at http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf* (last visited Mar. 20, 2015).

competition in the electric utility industry have resulted in independent power producers (IPPs)[88] producing approximately 37 percent of net generation in 20'13.[89] Electric utilities in some states remain vertically integrated without retail competition from IPPs. Today, there are over 3,000 public, private, and cooperative utilities in the U.S.[90] These utilities include both investor-owned utilities[91] and consumer-owned utilities.[92]

Over time, the grid slowly evolved into a complex, interconnected transmission system that allows electric generators to produce electricity that is then fed onto transmission lines at high voltages.[93] These

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[88] These entities are also referred to as merchant generators.

[89] Energy Information Administration, *Electric Power Annual, Table 1.1 Total Electric Power Summary Statistics, 2013 and 2012* (2015), *available at http://www.eia.gov/electricity/annual/html/epa_01_01.html*.

[90] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9 (2011), *available at http://www.raponline.org/document/download/id/645*.

[91] Investor-owned utilities are private companies that are financed by a combination of shareholder equity and bondholder debt. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9 (2011), *available at http://www.raponline.org/document/download/id/645*.

[92] Consumer-owned utilities include municipal utilities, public utility districts, cooperatives, and a variety of other entities such as irrigation districts. Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, at 9–10 (2011), *available at http://www.raponline.org/document/download/id/645*.

[93] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., at 5, 34 (1997). "The extent of the power system's short-run physical

larger transmission lines are able to access generation that is located more remotely, with transmission lines crossing many miles, including state borders.[94] Closer to end users, electricity is transformed into a lower voltage that is transported across localized

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interdependence is remarkable, if not entirely unique. No other large, multi-stage industry is required to keep every single producer in a region—whether or not owned by the same company—in immediate synchronization with all other producers." *Id.* at 34. "At an early date, those providing electric power recognized that peak use for one system often occurred at a different time from peak use in other systems. They also recognized that equipment failures occurred at different times in various systems. Analyses showed significant economic benefits from interconnecting systems to provide mutual assistance; the investment required for generating capacity could be reduced and reliability could be improved. This lead [sic] to the development of local, then regional, and subsequently three transmission grids that covered the U.S. and parts of Canada." Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 5–6 (2d ed. 2010).

[94] Burn, An Energy Journal, *The Electricity Grid: A History*, *available at http://burnanenergyjournal.com/the-electric-grid-a-history/* (last visited Mar. 9, 2015). Because of the ease and low cost of converting voltages in an alternating current (AC) system from one level to another, the bulk power system is predominantly an AC system rather than a direct current (DC) system. In an AC system, electricity cannot be controlled like a gas or liquid by utilizing a valve in a pipe. Instead, absent the presence of expensive control devices, electricity flows freely along all available paths, according to the laws of physics. U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 6 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/chl-3.pdf*.

transmission lines to homes and businesses.[95] Localized transmission lines make up the distribution system. These three components of the electricity system—generation, transmission, and distribution—are closely related and must work in coordination to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation's electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state, and local regulatory network to oversee the physically interconnected network. Facilities planned and constructed in one segment can impact facilities and operations in other segments and vice versa.

The North American electric grid has developed into a large, interconnected system.[96] Electricity from a diverse set of generation resources such as natural gas, nuclear, coal, and renewables is distributed over high-voltage transmission lines divided across the continental U.S. into three synchronous interconnections—the Eastern Interconnection, Western Interconnection, and the Texas Interconnection.[97] These three synchronous systems

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[95] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., at 5 (1997).

[96] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Rlackout in the United States and Canada: Causes and Recommendations*, at 5 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf*.

[97] Regulatory Assistance Project (RAP), *Electricity Regulation in the US: A Guide*, 2011, at 1, *available at http://www.raponline.org/document/download/id/645*.

each act like a single machine.[98] Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to industrial, business, and residential consumers. Unlike other industries where sources make operational decisions independently, the utility power sector is unique in that electricity system resources operate in a complex, interconnected grid system that is physically interconnected and operated on an integrated basis across large regions. Additionally, a federal, state, and local regulatory network oversees policies and

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[98] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010). In an amicus brief to the Supreme Court, a group of electrical engineers, economists, and physicists specializing in electricity explained, "*Energy* is transmitted, not electrons. Energy transmission is accomplished through the propagation of an electromagnetic wave. The electrons merely oscillate in place, but the *energy*—the *electromagnetic wave*—moves at the speed of light. The energized electrons making the lightbulb in a house glow are not the same electrons that were induced to oscillate in the generator back at the power plant. . . . Energy flowing onto a power network or grid *energizes the entire grid*, and consumers then draw undifferentiated energy from that grid. A networked grid flexes, and electric current flows, in conformity with physical laws, and those laws do not notice, let alone conform to, political boundaries. . . . The path taken by electric energy is the path of least resistance . . . or, more accurately, the *paths* of least resistance. . . . If a generator on the grid increases its output, the current flowing from the generator on all paths on the grid increases. These increases affect the energy flowing *into* each point in the network, which in turn leads to compensating and corresponding changes in the energy flows *out* of each point." Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, 8–9, 11, New York v. FERC, 535 U.S. 1 (2001) (No. 00-568).

practices that are applied to how the system is designed and operates. In this interconnected system, system operators must ensure that the amount of electricity available is precisely matched with the amount needed in real time. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units such as coal, nuclear, renewables, and natural gas, as well as demand-side resources,[99] such as EE[100] and demand response.[101] Generation, outages, and transmission changes in one part of the synchronous grid can affect the entire

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[99] "Measures using demand-side resources comprise actions taken on the customer's side of the meter to change the amount and/or timing of electricity use in ways that will provide benefits to the electricity supply system." David Crossley, Regulatory Assistance Project (RAP), *Effective Mechanisms to Increase the Use of Demand-Side Resources*, at 9 (2013), *available at www.raponline.org*.

[100] Energy efficiency is using less energy to provide the same or greater level of service. Demand-side energy efficiency refers to an extensive array of technologies, practices and measures that are applied throughout all sectors of the economy to reduce energy demand while providing the same, and sometimes better, level and quality of service.

[101] Demand response involves "[c]hanges in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." Federal Energy Regulatory Commission, *Reports on Demand Response & Advanced Metering*, (Dec. 23, 2014), *available at http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp*.

interconnected grid.[102] The interconnection is such that "[i]f a generator is lost in New York City, its affect is felt in Georgia, Florida, Minneapolis, St. Louis, and New Orleans."[103] The U.S. Supreme Court has similarly recognized the interconnected nature of the electricity grid.[104]

Today, federal, state, and local entities regulate electricity providers.[105] Overlaid on the physical electricity network is a regulatory network that has

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[102] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).

[103] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 160 (2d ed. 2010).

[104] *FederalPower Comm'n* v. *Florida Power & Light Co.*, 404 U.S. 453, at 460 (1972) (quoting a Federal Power Commission hearing examiner, "'If a housewife in Atlanta on the Georgia system turns on a light, every generator on Florida's system almost instantly is caused to produce some quantity of additional electric energy which serves to maintain the balance in the interconnected system between generation and load.'") (citation omitted). *See also New York* v. *FERC*, 535 U.S. 1, at 7 (2002) (stating that "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce.") (citation omitted). In *Federal Power Comm'n* v. *Southern California Edison Co.*, 376 U.S. 205 (1964), the Supreme Court found that a sale for resale of electricity from Southern California Edison to the City of Colton, which took place solely in California, was under Federal Power Commission jurisdiction because some of the electricity that Southern California Edison marketed came from out of state. The Supreme Court stated that, "'federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.'" *Id.* at 210 (quoting *Connecticut Light & Power Co.* v. *Federal Power Commission*, 324 U.S. 515, 529 (1945) (emphasis omitted)).

[105] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).

developed over the last century or more. This regulatory network "plays a vital role in the functioning of all other networks, sometimes providing specific rules for functioning while at other times providing restraints within which their operation must be conducted." [106] This unique regulatory network results in an electricity grid that is both physically interconnected and connected through a network of regulation on the local, state, and federal levels. This regulation seeks to reconcile the fact that electricity is a public good with the fact that facilities providing that electricity are privately owned. [107] While this regulation began on the state and local levels, federal regulation of the electricity system increased over time. With the passage of the EPAct 1992 and the EPAct 2005, the federal government's role in electricity regulation greatly increased.[108] "The role of the regulator now includes support for the development of open and fair wholesale electric markets, ensuring equal access to the transmission system and more hands-on oversight and control of the planning and operating rules for the industry."[109]

2. Electric System Dispatch

System operators typically dispatch the electric system through a process known as Security

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[106] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 213 (2d ed. 2010).

[107] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 213 (2d ed. 2010).

[108] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).

[109] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 214 (2d ed. 2010).

Constrained Economic Dispatch.[110] Security Constrained Economic Dispatch has two components—economic generation of generation facilities and ensuring that the electric system remains reliable.[111] Electricity demand varies across geography and time in response to numerous conditions, such that electric generators are constantly responding to changes in the most reliable and cost-effective manner possible. The cost of operating electric generation varies based on a number of factors, such as fuel and generator efficiency.

The decision to dispatch any particular electric generator depends upon the relative operating cost, or marginal cost, of generating electricity to meet the last increment of electric demand. Fuel is one common variable cost—especially for fossil-fueled generators. Coal plants will often have considerable variable costs

[110] *Economic Dispatch: Concepts, Practices and Issues*, FERC Staff Presentation to the Joint Board for the Study of Economic Dispatch, Palm Springs, California (Nov. 13, 2005), *available at http://www.ferc.gov/CalendarFiles/20051110172953-FERC%20Staff%20Presentation.pdf*.

[111] Federal Energy Regulatory Commission, *Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress* (July 31, 2006). The Energy Policy Act of 2005 defined economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 (2005), section 1234(b), *available at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf*.

associated with running pollution controls.[112] Renewables, hydroelectric, and nuclear have little to no variable costs. If electricity demand decreases or additional generation becomes available on the system, this impacts how the system operator will dispatch the system. EGUs using technologies with relatively low variable costs, such as nuclear units and RE, are for economic reasons generally operated at their maximum output whenever they are available. When lower cost units are available to run, higher variable cost units, such as fossil-fuel generators, are generally the first to be displaced.

In states with cost-of-service regulation of vertically-integrated utilities, the utilities themselves form the balancing authorities who determine dispatch based upon the lowest marginal cost. These utilities sometimes arrange to buy and sell electricity with other balancing authorities. RTOs and ISOs coordinate, control, and monitor electricity transmission systems to ensure cost-effective and reliable delivery of power, and they are independent from market participants.

3. Reliability Considerations

The reliability of the electric system has long been a focus of the electric industry and regulators. Industry developed a voluntary organization in the early 1960s that assisted with bulk power system coordination in

[112] Variable costs also include costs associated with operation and maintenance and costs of operating a pollution control and/or emission allowance charges.

the U.S. and Canada.[113] In 1965, the northeastern U.S. and southeastern Ontario, Canada experienced the largest power blackout to date, impacting 30 million people.[114] In response to the 1965 blackout and a Federal Power Commission recommendation,[115] industry developed the National Electric Reliability Council (NERC) and nine reliability councils. The organization later became known as the North American Electric Reliability Council to recognize Canada's participation.[116] The North American Electric Reliability Council became the North American Electric Reliability Corporation in 2007.[117]

In August 2003, North America experienced its worst blackout to date creating an outage in the

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[113] North American Electric Reliability Corporation, *History of NERC*, at 1 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf*.

[114] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 39 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*

[115] The Federal Power Commission, a precursor to FERC, recommended "the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information and to review, discuss and assist in resolving interregional coordination matters." North American Electric Reliability Corporation, *History of NERC*, at 1 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf*.

[116] North American Electric Reliability Corporation, *History of NERC*, at 2 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20A UG13.pdf*.

[117] North American Electric Reliability Corporation, *History of NERC*, at 4 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20A UG13.pdf*.

Midwest, Northeast, and Ontario, Canada.[118] This blackout was massive in scale impacting an area with an estimated 50 million people and 61,800 megawatts of electric load.[119] The U.S. and Canada formed a joint task force to investigate the causes of the blackout and made recommendations to avoid similar outages in the future. One of the task force's major recommendations was that the U.S. Congress should pass legislation making electric reliability standards mandatory and enforceable.[120]

Congress responded to this recommendation in EPAct 2005, adding a new section 215 to the Federal Power Act making reliability standards mandatory and enforceable and authorizing the creation of a new Electric Reliability Organization (ERO). Under this new system, FERC certifies an entity as the ERO. The ERO develops reliability standards, which are subject to FERC review and approval. Once FERC approves reliability standards the ERO may enforce those

[118] North American Electric Reliability Corporation, *History of NERC*, at 3 (2013), *available at http://www.nerc.com/AboutNERC/Documents/History%20AUG13.pdf*.

[119] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 1 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf*. The outage impacted areas within Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario. *Id.*

[120] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 2 (Apr. 2004), *available at http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf*.

standards or FERC can do so independently.[121] In 2006, the Federal Energy Regulatory Commission (FERC) certified NERC as the ERO.[122] "NERC develops and enforces Reliability Standards; monitors the Bulk-Power System; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel."[123]

The U.S., Canada, and part of Mexico are divided up into eight reliability regional entities.[124] These regional entities include Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council

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[121] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218, at P 3 (2007) (citing 16 U.S.C. 824o(e)(3)).

[122] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 (2006).

[123] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 2 (Aug. 2013), *available at http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf*.

[124] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 49–50 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

(WECC).[125] Regional entity members come from all segments of the electric industry.[126] NERC delegates authority, with FERC approval, to these regional entities to enforce reliability standards, both national and regional reliability standards, and engage in other standards-related duties delegated to them by NERC.[127] NERC ensures that there is a consistency of application of delegated functions with appropriate regional flexibility.[128] NERC divides the country into

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[125] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, at 50 (2012), *available at http://www.ferc.gov/market-oversight/guide/energy-primer.pdf*.

[126] North American Electric Reliability Corporation, *Key Players*, *available at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx* (last visited Mar. 12, 2015). "The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers." *Id.*

[127] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 5 (2013), *available at http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf*. For example, a regional entity may propose reliability standards, including regional variances or regional reliability standards required to maintain and enhance electric service reliability, adequacy, and security in the region. *See, e.g.*, *Amended and Restated Delegation Agreement Between North American Reliability Corporation and Midwest Reliability Organization, Bylaws of the Midwest Reliability Organization, Inc.*, Section 2.2 (2012), *available at http://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/MRO_RDA_Effective_20130612.pdf*.

[128] North American Electric Reliability Corporation, *Frequently Asked Questions*, at 5 (2013), *available at http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf*.

assessment areas and annually analyzes the reliability, adequacy, and associated risks that may affect the upcoming summer, winter, and long-term, 10-year period. Multiple other entities such as FERC, the Department of Energy, state public utility commissions, ISOs/RTOs, [129] and other planning authorities also consider the reliability of the electric system. There are numerous remedies that can be utilized to solve a potential reliability problem, including long-term planning, transmission system upgrades, installation of new generating capacity, demand response, and other demand side actions.

4. Modern Electric System Trends

Today, the electricity sector is undergoing a period of intense change. Fossil fuels—such as coal, natural gas, and oil—have historically provided a large percentage of electricity in the U.S., along with nuclear power, with smaller amounts provided by other types of generation, including renewables such

[129] ISOs/RTOs plan for system needs by "effectively managing the load forecasting, transmission planning, and system and resource planning functions." For example, the New York Independent System Operator (NYISO) conducts reliability planning studies, which "are used to assess current reliability needs based on user trends and historical energy use." NYISO, Planning Studies, available at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. *See also* PJM, *Reliability Assessments*, *available at https://www.pjm.com/planning/rtep-development/reliability-assessments.aspx* (stating that the PJM "Regional Transmission Expansion Planning (RTEP) process includes the development of periodic reliability assessments to address specific system reliability issues in addition to the ongoing expansion planning process for the interconnection process of generation and merchant transmission.").

as wind, solar, and hydroelectric power. Coal provided the largest percentage of the fossil fuel generation.[130] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[131] In 2013, fossil fuels supplied 67 percent of U.S. electricity,[132] but the amount of renewable generation capacity continued to grow.[133] From 2007 to 2014, use of lower- and zero-carbon energy sources such as wind and solar grew, while other major energy sources such as coal and petroleum generally experienced declines.[134]

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[130] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[131] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[132] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf* (last visited May 26, 2015).

[133] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following RE sources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

[134] U.S. Energy Information Administration, "Table 7.2b Electricity Net Generation: Electric Power Sector" data from Monthly Energy Review May 2015, available at

Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[135] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. came in the form of natural gas or RE facilities.[136] In 2015, the U.S. Energy Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020.[137] The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning), with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.

While the change in the resource mix has accelerated in recent years, wind, solar, other renewables, and EEresources have been reliably

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http://www.eia.gov/totalenergy/data/monthby/pdf/sec7_6.pdf (last visited May 26, 2015).

[135] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, 2015 *Factbook: Sustainable Energy in America*, at 16 (2015), *available at http://www.bcse.org/images/2015%20Sustainable%20Energy%20in%20America%20Factbook.pdf*. Bloomberg gave projections for 2014 values, accounting for seasonality, based on latest monthly values from EIA (data available through October 2014).

[136] Energy Information Administration, *Electricity: Form EIA-860 detailed data* (Feb. 17, 2015), available at *http://www.eia.gov/electricity/data/eia860/*.

[137] EIA, *Annual Energy Outlook for 2015 with Projections to 2040, Final Release*, *available at http://www.eia.gov/forecasts/AEO/pdf/0383(2015).pdf*. The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement. In 2025, the average age of the coal-fired generating fleet is projected to be 49 years old, and 20 percent of those units would be more than 60 years old if they remain in operation at that time. In its 2013 Report Card for America's Infrastructure, the American Society for Civil Engineers noted that "America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s."[138] While there has been an increased investment in electric transmission infrastructure since 2005, the report also found that "ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions."[139] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively with the lowest possible emissions and the greatest efficiency.

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[138] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

[139] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard .org/energy/.*

Natural gas has a long history of meeting electricity demand in the U.S., with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 32 percent between 2005 and 2014.[140] In 2014, natural gas accounted for approximately 27 percent of net generation.[141] EIA projects that this demand growth will continue with its Annual Energy Outlook 2015 (AEO 2015) Reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[142]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for RE development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and

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[140] U.S. Energy Information Administration (EIA), Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (*All Sectors), 2005-February 2015* (2015), *available athttp://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1* (last visited May 26, 2015).

[141] *Id.*

[142] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040*, at 24–25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.* According to the EIA, the reference case assumes, "Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. North Sea Brent crude oil prices rise to $141/barrel (bbl) (2013 dollars) in 2040." *Id.* at 1. The EIA provides complete projection tables for the reference case in Appendix A of its report.

significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying facilities (QFs).[143] QFs were either cogeneration facilities[144] or small generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[145] Through PURPA, Congress supported the development of more RE generation in the U.S. States have also taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[146]

Use of RE continues to grow rapidly in the U.S. In 2013, electricity generated from renewable technologies, including conventional hydropower, represented 13 percent of total U.S. electricity, up

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[143] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220–221 (2d ed. 2010).

[144] Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220–221 (2d ed. 2010).

[145] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 220–221 (2d ed. 2010).

[146] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040*, at LR-5 (2014), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf* (last visited May 26, 2015).

from 9 percent in 2005.[147] In 2013, U.S. non-hydro RE capacity for the total electric power industry exceeded 80,000 MW, reflecting a fivefold increase in just 15 years.[148] In particular, there has been substantial growth in the wind and photovoltaic (PV) markets in the past decade. Since 2009, U.S. wind generation has tripled and solar generation has grown twenty-fold.[149]

The global market for RE is projected to grow to $460 billion per year by 2030.[150] RE growth is further encouraged by the significant amount of existing natural resources that can support RE production in the U.S.[151] In the Energy Information Administration's Annual Energy Outlook 2015, RE generation grows substantially from 2013 to 2040 in

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[147] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES-6 (2014) and Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf*.

[148] Non-hydro RE capacity for the total electric power industry was more than 16,000 megawatts (MW) in 1998. Energy Information Administration, 1990–2013 Existing Nameplate and Net Summer Capacity by Energy Source Producer Type and State (EIA-860), *available at http://www.eia.gov/electricity/data/state/*.

[149] Energy Information Administration, Monthly Energy Review, May 2015, Table 7.2b, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf*.

[150] "Global Renewable Energy Market Outlook." Bloomberg New Energy Finance (Nov. 16, 2011), *available at http://bnef.com/WhitePapers/download/53*.

[151] Lopez et al., NREL, "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis," (July 2012).

the reference case and all alternative cases.[152] In the reference case, RE generation increases by more than 70 percent from 2013 to 2040 and accounts for over one-third of new generation capacity.[153]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and EE to the forefront of U.S. energy policy.[154] This trend continued in the early 1990s. EE has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states[155] have "enacted long-term

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[152] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at 25 (2015), available at *http://www.eia.gov/ forecasts/aeo/pdf/0383(2015).pdf*.

[153] Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040, at ES-6 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf* (last visited May 27, 2015).

[154] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, at 1 (2007), *available at http://www.eei.org/whatwedo/PublicPolicy Advocacy/StateRegulation/Documents/Making_Business_Ener gy_Efficiency.pdf*. Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975—the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to "develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances." Alliance to Save Energy, *History of Energy Efficiency*, at 6 (2013) (citing Anders, "The Federal Energy Administration," 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975–1976)), *available at https://www.ase.org/sites/ase.org/files/resources/Media%20b rowser/ee_commission_history_report_2-1-13.pdf*.

[155] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf*.

(3+ years), binding energy savings targets, or energy efficiency resource standards (EERS)."[156] Funding for EE programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[157]

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

E. Clean Air Act Regulations for Power Plants

In this section, we provide a general description of major CAA regulations for power plants. We refer to these in later sections of this preamble.

1. Title IV Acid Rain Program

The EPA's Acid Rain Program, established in 1990 under Title IV of the CAA, addresses the presence of acidic compounds and their precursors (*i.e.*, SO_2 and NO_X), in the atmosphere by targeting "the principal sources" of these pollutants through an SO_2 cap-and-

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ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

[156] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.*

[157] American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency Continued Scorecard*, at 17 (Nov. 2013), *available at http://aceee.org/sites/default/files/publications/researchreports/el3k.pdf.*

trade program for fossil-fuel fired power plants and through a technology based NO_X emission limit for certain utility boilers. Altogether, Title IV was designed to achieve reductions of ten million tons of annual SO_2 emissions, and, in combination with other provisions of the CAA, two million tons of annual NO_X emissions.[158]

The SO_2 cap-and-trade program was implemented in two phases. The first phase, beginning in 1995, targeted one-hundred and ten named power plants, including specific generator units at each plant, requiring the plants to reduce their cumulative emissions to a specific level.[159] Under certain conditions, the owner or operator of a named power plant could reassign an affected unit's reduction requirement to another unit and/or request an extension of two years for meeting the requirement.[160] Congress also established an energy conservation and RE reserve from which up to 300,000 allowances could be allocated for qualified energy conservation measures or qualified RE.[161]

The second phase, beginning in 2000, expanded coverage to more than 2,000 generating units and set a national cap at 8.90 million Ions.[162] Generally, allowances were allocated at a rate of 1.2 lbs/mmBtu multiplied by the unit's baseline and divided by

[158] 42 U.S.C. 7651(b).

[159] 42 U.S.C. 7651c (Table A).

[160] 42 U.S.C. 7651c(b) and (d).

[161] 42 U.S.C. 7651c(f) and (g)

[162] U.S. Dept. of Energy, Energy Information Administration, "The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update," p. vii. (March 1997).

2000.[163] However, bonus allowances could be awarded to certain units.

Title IV also required the EPA to hold or sponsor annual auctions and sales of allowances for a small portion of the total allowances allocated each year. This ensured that some allowances would be directly available for new sources, including independent power production facilities.[164]

The provisions of the EPA's Acid Rain Program are implemented through permits issued under the EPA's Title V Operating Permit Program.[165] In accordance with Title IV, moreover, each Title V permit application must include a compliance plan for the affected source that details how that source expects to meet the requirements of Title IV.[166]

2. Transport Rulemakings

CAA section 110(a)(2)(D)(i)(I), the "Good Neighbor Provision," requires SIPs to prohibit emissions that "contribute significantly to nonattainment . . . or interfere with maintenance" of the NAAQS in any other state.[167] If the EPA finds that a state has failed to submit an approvable SIP, the EPA must issue a

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[163] *See* 42 U.S.C. 7651d.

[164] 42 U.S.C. 7651o.

[165] 42 U.S.C. 7651g.

[166] Such plans may simply state that the owner or operator expects to hold sufficient allowances or, in the case of alternative compliance methods, must provide a "comprehensive description of the schedule and means by which the unit will rely on one or more alternative methods of compliance in the manner and time authorized under [Title IV]." 42 U.S.C. 7651g(b).

[167] 42 U.S.C. 7410(a)(2)(D)(i)(I).

federal implementation plan (FIP) to prohibit those emissions "at any time" within the next two years.[168]

In three major rulemakings—the NO_X SIP Call,[169] the Clean Air Interstate Rule (CAIR),[170] and the Cross State Air Pollution Rule (CSAPR)[171]—the EPA has attempted to delineate the scope of the Good Neighbor Provision. These rulemakings have several features in common. Although the Good Neighbor Provision does not speak specifically about EGUs, in all three rulemakings, the EPA set state emission "budgets" for upwind states based in part on emissions reductions achievable by EGUs through application of cost-effective controls. Each rule also adopted a phased approach to reducing emissions with both interim and final goals.

a. *NO_X SIP Call*. In 1998, the EPA promulgated the NO_X SIP Call, which required 23 upwind states to reduce emissions of NO_X that would impact downwind areas with ozone problems. The EPA determined emission reduction requirements based on reductions achievable through "highly cost-effective" controls—*i.e.*, controls that would cost on average no more than $2,000 per ton of emissions reduced.[172] The EPA determined that a uniform emission rate on large EGUs coupled with a cap-and-trade program was one

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[168] *EPA* v. *EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1600–01 (2014) (citing 42 U.S.C. 7410(c)).

[169] 63 FR 57356 (Oct. 27, 1998).

[170] 70 FR 25162 (May 12, 2005).

[171] 76 FR 48208 (Aug. 8, 2011).

[172] 63 FR at 57377–78.

such set of highly cost-effective controls.[173] Accordingly, the EPA established an interstate cap-and-trade program—the NO_X Budget Trading Program—as a mechanism for states to reduce emissions from EGUs and other sources in a highly cost-effective manner. The D.C. Circuit upheld the NO_X SIP Call in most significant respects, including its use of costs to apportion emission reduction responsibilities.[174]

b. *Clean Air Interstate Rule (CAIR).* In 2005, the EPA promulgated CAIR, which required 28 upwind states to reduce emissions of NO_X and SO_2 that would impact downwind areas with projected nonattainment and maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based on "controls that are known to be highly cost effective for EGUs."[175] The EPA established cap-and-trade programs for sources of NO_X and SO_2 in states that chose to participate in the trading programs via their SIPs and for states ultimately subject to a FIP.[176] As relevant here, the D.C. Circuit remanded CAIR in *North Carolina* v. *EPA* due to in part the structure of its interstate trading provisions and the way in which EPA applied the cost-effective standard, but kept the

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[173] 63 FR at 57377–78. In addition to EGUs, the NOx SIP Call also set budgets based on highly cost-effective emission reductions from certain other large sources. *Id.*

[174] *Michigan* v. *EPA*, 213 F.3d 663 (D.C. Cir. 2000).

[175] 70 FR at 25163.

[176] 70 FR at 25273–75; 71 FR 25328 (April 28, 2006).

rule in place while the EPA developed an acceptable substitute.[177]

c. *Cross-state Air Pollution Rule (CSAPR).* In 2011, the EPA promulgated CSAPR, which required 27 upwind states to reduce emissions of NO_X and SO_2 that would impact downwind areas with projected nonattainment and maintenance problems for ozone and $PM_{2.5}$. The EPA determined emission reduction requirements based in part on the reductions achievable at certain cost thresholds by EGUs in each state, with certain provisions developed to account for the need to ensure reliability of the electric generating system.[178] In the same action establishing these emission reduction requirements, the EPA promulgated FIPs that subjected states to trading programs developed to achieve the necessary reductions within each state.[179] The U.S. Supreme Court upheld the EPA's use of cost to set emission reduction requirements, as well as its authority to issue the FIPs.[180]

3. Clean Air Mercury Rule

On March 15, 2005, the EPA issued a rule to control mercury (Hg) emissions from new and existing fossil fuel-fired power plants under CAA section 111(b) and (d). The rule, known as the Clean Air Mercury Rule

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[177] 531 F.3d 896, 917–22 (D.C. Cir. 2008), *modified on rehearing* 550 F.3d 1176, 1178 (D.C. Cir. 2008).

[178] 76 FR at 48270. The EPA adopted this approach in part to comport with the D.C. Circuit's opinion in *North Carolina* v. *EPA* remanding CAIR. *Id.* at 48270–71.

[179] 76 FR at 48209–16.

[180] *EPA* v. *EME Homer City Generation, L.P.*, 134 S. Ct. 1584 (2014).

(CAMR), established, in relevant part, a nationwide cap-and-trade program under CAA section 111(d), which was designed to complement the cap-and-trade program for SO_2 and NO_X emissions under the Clean Air Interstate Rule (CAIR), discussed above.[181] Though CAMR was later vacated by the D.C. Circuit on account of the EPA's flawed CAA section 112 delisting rule, the court declined to reach the merits of the EPA's interpretation of CAA section 111(d).[182] Accordingly, CAMR continues to be an informative model for a cap-and-trade program under CAA section 111(d).

The cap-and-trade program in CAMR was designed to take effect in two phases: in 2010, the cap was set at 38 tons of mercury per year, and in 2018, the cap would be lowered to 15 tons per year. The Phase I cap was set at a level reflecting the co-benefits of CAIR as determined through economic and environmental modeling.[183] For the more stringent Phase II cap, the EPA projected that sources would "install SCR [selective catalytic reduction] to meet their SO_2 and NO_X requirements and take additional steps to address the remaining Hg reduction requirements under CAA section 111, including adding Hg-specific control technologies (model applies ACI [activated carbon injection]), additional scrubbers and SCR,

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[181] *See* 70 FR 28606 (May 18, 2005).

[182] *New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008).

[183] 70 FR 28606, at 28617. The EPA's projections under CAIR showed a significant number of affected sources would install scrubbers for SO_2 and selective catalytic reduction for NO_X on coal-fired power plants, which had the co-benefit of capturing mercury emissions. *Id.* at 28619.

dispatch changes, and coal switching."[184] Based on this analysis, EPA determined that the BSER "refers to the combination of the cap-and-trade mechanism and the technology needed to achieve the chosen cap level."[185]

To accompany the nationwide emissions cap, the EPA also assigned a statewide emissions budget for mercury. Pursuant to CAA section 111(d), states would be required to submit plans to the EPA "detailing the controls that will be implemented to meet its specified budget for reductions from coal-fired Utility Units." [186] Of course, states were "not required to adopt and implement" the emission trading program, "but they [were] required to be in compliance with their statewide Hg emission budget."[187]

4. Mercury Air Toxics Rule

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, nervous system damage, cancer, and other serious health

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[184] 70 FR 28606, at 28619.

[185] 70 FR 28606, at 28620.

[186] 70 FR 28606, at 28621.

[187] 70 FR 28606, at 28621. That said, states could "require reductions beyond those required by the [s]tate budget." *Id.* at 28621.

effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.*, sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is "appropriate and necessary" and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule.

White Stallion Energy-Center v. *EPA*, 748 F.3d 1222 (D.C. Cir. 2014). In *Michigan* v. *EPA*, case no. 14-46, the U.S. Supreme Court reversed the portion of the D.C. Circuit decision finding the EPA was not required to consider cost when determining whether regulation of EGUs was "appropriate" pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of whether the EPA erred in not considering cost when making this threshold determination. The Court's decision did not disturb any of the other holdings of the D.C. Circuit. The Court remanded the case to the D.C. Circuit for further proceedings, and the MATS rule remains in place at this time.

5. Regional Haze Rule

Under CAA section 169A, Congress "declare[d] as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility" in national parks and wilderness areas that results from anthropogenic emissions.[188] To achieve this goal, Congress directed the EPA to promulgate regulations directing states to submit SIPs that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal. . . ."[189] One such measure that Congress deemed necessary to make reasonable progress was a requirement that certain older stationary sources that cause or contribute to visibility impairment "procure, install, and operate, as expeditiously as practicable . . . the

[188] 42 U.S.C. 7491(a)(1).

[189] 42 U.S.C. 7491(b)(2)

best available retrofit technology," more commonly referred to as BART.[190] When determining BART for large fossil-fuel fired utility power plants, Congress required states to adhere to guidelines to be promulgated by the EPA.[191] As with other SIP-based programs, the EPA is required to issue a FIP within two years if a state fails to submit a regional haze SIP or if the EPA disapproves such SIP in whole or in part.[192]

In 1999, the EPA promulgated the Regional Haze Rule to satisfy Congress' mandate that EPA promulgate regulations directing states to address visibility impairment.[193] Among other things, the Regional Haze Rule allows states to satisfy the Act's BART requirement either by adopting source-specific emission limitations or by adopting alternatives, such as emissions-trading programs, that achieve greater reasonable progress than would source-specific BART.[194] The Ninth Circuit and D.C. Circuit have both upheld the EPA's interpretation that CAA section 169A(b)(2) allows for BART alternatives in lieu of source-specific BART.[195] In 2005, the EPA promulgated BART Guidelines to assist states in determining which sources are subject to BART and

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[190] 42 U.S.C. 7491(b)(2)(A).

[191] 42 U.S.C. 7491(b)(2).

[192] 42 U.S.C. 7410(c); 7491(b)(2)(A).

[193] 64 FR 35714 (July 1, 1999) (codified at 40 CFR 51.308–309).

[194] 40 CFR 51.308(e)(1) & (2).

[195] *See Utility Air Regulatory Grp.* v. *EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Ctr. for Econ. Dev.* v. *EPA*, 398 F.3d 653 (D.C. Cir. 2005); *Cent. Ariz. Water Dist.* v. *EPA*, 990 F.2d 1531 (9th Cir. 1993).

what emission limitations to impose at those sources.[196]

The Regional Haze Rule set a goal of achieving natural visibility conditions by 2064 and requires states to revise their regional haze SIPs every ten years.[197] The first planning period, which ends in 2018, focused heavily on the BART requirement. States (or the EPA in the case of FIPs) made numerous source-specific BART determinations, and developed several BART alternatives, for utility power plants. For the next planning period, states will need to determine whether additional controls are necessary at these plants (and others that were not subject to BART) in order to make reasonable progress towards the national visibility goal.[198]

F. Congressional Awareness of Climate Change in the Context of the Clean Air Act Amendments[199]

During its deliberations on the 1970 Clean Air Act Amendments, Congress learned that ongoing pollution, including from manmade carbon dioxide, could "threaten irreversible atmospheric and climatic changes."[200] At that time, Congress heard the views of scientists that carbon dioxide emissions tended to

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[196] 70 FR 39104 (July 6, 2005) (codified at 40 CFR pt. 51, app. Y).

[197] *See* 40 CFR 51.308(d)(l)(i)(B), (f).

[198] *See* 42 U.S.C. 7491(b)(2); 40 CFR 51.308(d)(3).

[199] The following discussion is not meant to be exhaustive. There are many other instances outside the context of the CAA, before and after 1970, when Congress discussed or was presented with evidence on climate change.

[200] Sen. Scott, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 349.

increase global temperatures, but that there was uncertainty as to the extent to which those increases would be offset by the decreases in temperatures brought about by emissions of particulates. President Nixon's Council on Environmental Quality (CEQ) reported that "the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate."[201] The CEQ's First Annual Report, which was transmitted to Congress, devoted a chapter to "Man's Inadvertent Modification of Weather and Climate."[202] Moreover, Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service, testified before the House Subcommittee on Public Health that "the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth."[203] Administrator Johnson explained that the Nixon

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[201] Council on Environmental Quality, "The First Annual Report of the Council on Environmental Quality," p. 110 (Aug. 1970) (recognizing also that "[man] can increase the carbon dioxide content of the atmosphere by burning fossil fuels" and postulating that an increase in the earth's average temperature by about 2° to 3° F "could in a period of decades, lead to the start of substantial melting of ice caps and flooding of coastal regions.").

[202] Council on Environmental Quality, "The First Annual Report of the Council on Environmental Quality," p. 93–104 (Aug. 1970)

[203] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony) Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

Administration was "concerned . . . that neither of these things happen" and that they were "watching carefully the kind of prognosis, the kind of calculations that the scientists make to look at the continuous balance between heat and cooling of the total earth's atmosphere."[204] He concluded that "[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these."[205]

Scientific reports on climatic change continued to gain traction in Congress through the mid-1970s, including while Congress was considering the 1977 CAA Amendments. However, uncertainty continued as to whether the increased warming brought about by carbon dioxide emissions would be offset by cooling brought about by particulate emissions.[206] Congress

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[204] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony) Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

[205] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony) Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381.

[206] For instance, while scientists, such as Stephen Schneider of the National Center for Atmospheric Research, testified that "manmade pollutants will affect the climate," they believed that we would "see a general cooling of the Earth's atmosphere." Rep. Scheuer, H. Debates on H.R. 10498 (Sept. 15, 1976), 1977 CAA Legis. Hist. at 6477. Additionally, the Department of Transportation's climatic impact assessment program and the Climatic Impact Committee of the National Research Council, National Academies of Science and Engineering both reported that "warming or cooling" could occur. *Id.* at 6476. *See also* Sen.

ordered, as part of the 1977 CAA Amendments, the National Oceanic and Atmospheric Administration to research and monitor the stratosphere "for the purpose of early detection of changes in the stratosphere and climatic effects of such changes."[207]

Between the 1977 and 1990 Clean Air Act Amendments, scientific uncertainty yielded to the predominant view that global warming "was likely to dominate on time scales that would be significant to human societies."[208] In fact, as part of the 1990 Clean Air Act Amendments, Congress specifically required the EPA to collect data on carbon dioxide emissions—the most significant of the GHGs—from all sources subject to the newly enacted operating permit program under Title V.[209] Although Congress did not require the EPA to take immediate action to address climate change, Congress did identify certain tools that were particularly helpful in addressing climate change in the utility power sector. The Senate report

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Bumpers, S. Debates on S. 3219 (August 3, 1976), 1977 CAA Legis. Hist. at 5368 (inserting "Summary of Statements Received [in the Subcommittee on the Environment and the Atmosphere]from Professional Societies for the Hearings on Effects of Chronic Pollution" into the record, which noted that "there is near unamity [sic] that carbon dioxide concentrations in the atmosphere are increasing rapidly.").

[207] "Clean Air Act Amendments of 1977," § 125, 91 Stat, at 728.

[208] Peterson, Thomas C., William M. Connolley, and John Fleck, "The Myth of the 1970s Global Cooling Scientific Consensus," Bulletin of the American Meteorological Society, p. 1326 (September 2008), *available at http://journals.ametsoc.org/doi/pdf/10.1175/2008BAMS2370.1.*

[209] "Clean Air Act Amendments of 1990," § 820, 104 Stat, at 2699.

discussing the acid rain provisions of Title IV noted that some of the measures that would reduce coal-fired power plant emissions of the precursors to acid rain would also reduce those facilities' emissions of CO_2. The report stated:

> Energy efficiency is a crucial tool for controlling the emissions of carbon dioxide, the gas chiefly responsible for the intensification of the atmospheric 'greenhouse effect.' In the last several years, the Committee has received extensive scientific testimony that increases in the human-caused emissions of carbon dioxide and other greenhouse gases will lead to catastrophic shocks in the global climate system. Accordingly, new title IV shapes an acid rain reduction policy that encourages energy efficiency and other policies aimed at controlling greenhouse gases.[210]

Similarly, Title IV provisions to encourage RE were justified because "renewables not only significantly curtail sulfur dioxide emissions, but they emit little or no nitrogen oxides and carbon dioxide".[211]

G. International Agreements and Actions

In this final rule, the U.S. is taking action to limit GHGs from one of its largest emission sources. Climate change is a global problem, and the U.S. is not alone in taking action to address it. The UNFCCC[212]

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[210] Sen. Chafee, S. Debate on S. 1630 (Jan. 24, 1990), 1990 CAA Legis. Hist. at 8662.

[211] Additional Views of Rep. Markey and Rep. Moorhead, H.R. Rep. No. 101-490, at 674 (May 17, 1990).

[212] *http://unfccc.int/2860.php.*

is the international treaty under which countries (called "Parties") cooperatively consider what can be done to limit anthropogenic climate change[213] and adapt to climate change impacts. Currently, there are 195 Parties to the UNFCCC, including the U.S. The Conference of the Parties (COP) meets annually and is currently considering commitments countries can make to limit emissions after 2020. The 2015 COP will be in Paris and is expected to represent an historic step for climate change mitigation. The Parties to the UNFCC will meet to establish a climate agreement that applies to all countries and focuses on reducing GHG emissions. Such an outcome would send a beneficial signal to the markets and civil society about global action to address climate change.

Many countries have announced their intended post-2020 commitments already, and other countries are expected to do so before December. In April 2015, the U.S. announced its commitment to reduce GHG emissions 26–28 percent below 2005 levels by 2025.[214]

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[213] Article 2, Objective, The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, 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, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner, *http://unfccc.int/files/essential_background/convention/background/application/pdf/convention_text_with_annexes_english_for_posting.pdf*

[214] United States Cover Note to Intended Nationally Determined Contribution (INDC). *Available online at:*

As Parties to both the UNFCCC and the Kyoto Protocol,[215] the European Union (EU) and member countries have taken aggressive action to reduce GHG emissions.[216] EU initiatives to reduce GHG emissions include the EU Emissions Trading System, legislation to increase the adoption of RE sources, strengthened EE targets, vehicle emission standards, and support for the development of CCS technology for use by the power sector and other industrial sources. In 2009, the EU announced its "20-20-20 targets," including a 20 percent reduction in GHG emissions from 1990 levels by 2020, an increase of 20 percent in the share of energy consumption produced by renewable resources, and a 20 percent improvement in EE. In March 2015, the EU announced its commitment to reduce domestic GHG emissions by at least 40% from 1990 levels by 2030.

Recently, China has also agreed to take action to address climate change. In November 2014, in a joint announcement by President Obama and China's President Xi, China pledged to curtail GHG emissions, with emissions peaking in 2030 and then declining thereafter, and to increase the share of energy from non-carbon sources (solar, wind, hydropower, nuclear) to 20 percent by 2030.

Mexico is committed to reduce unconditionally 25 percent of its emissions of GHGs and short-lived

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http://www4.unfccc.int/submissions/INDC/Published%20 Documents/United%20States%20of%20America/l/U.S.%20Cov er%20Note %20INDC% 20and%20Accompanying%20lnformatio n.pdf.

[215] *http://unfccc.int/kyoto_protocol/items/ 2830.php.*

[216] *http://ec.europa.eu/clima/policies/brief/eu/index_en.htm.*

climate pollutants (below business as usual) for the year 2030. This commitment implies a 22 percent reduction of GHG emissions and a 51 percent reduction of black carbon emissions.

Brazil has reduced its net CO_2 emissions more than any other country through a historic effort to slow forest loss. The deforestation rate in Brazil in 2014 was roughly 75 percent below the average for 1996 to 2005.[217]

Together, countries that have already announced their intended post-2020 commitments, including the U.S., China, European Union, Mexico, Russian Federation and Brazil, make up a large majority of global emissions.

President Obama's Climate Action Plan contains a number of policies and programs that are intended to cut carbon pollution that causes climate change and affects public health. The Clean Power Plan is a key component of the plan, addressing the nation's largest source of emissions in a comprehensive manner. Collectively, these policies will help spark business innovation, result in cleaner forms of energy, create jobs, and cut dependence on foreign oil. They also demonstrate to the rest of the world that the U.S. is contributing its share of the global effort that is needed to address climate change.[218] This

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[217] *http://www.nature.com/news/stopping-deforestation-battle-for-the-amazon-1.17223.*

[218] President Obama stated, in announcing the Climate Action Plan:

"The actions I've announced today should send a strong signal to the world that America intends to take bold action to reduce carbon pollution. We will continue to lead by the power of our demonstration encourages other major economies to take on similar contributions, which is critical given the global impact of GHG emissions. The State Department Special Envoy for Climate Change Todd Stern, the lead U.S. climate change negotiator, noted the connection between domestic and international action to address climate change in his speech at Yale University on October 14, 2014:

> This mobilization of American effort matters. Enormously. It matters because the United States is the biggest economy and largest historic emitter of greenhouse gases. Because, here, as in so many areas, we feel a responsibility to lead. And because here, as in so many areas, we find that American commitment is indispensable to effective international action.
>
> And make no mistake—other countries see what we are doing and are taking note. As I travel the world and meet with my counterparts, the palpable engagement of President Obama and his team has put us in a stronger, more credible position than ever before.

This final rule demonstrates to other countries that the U.S. is taking action to limit GHG emissions from its largest emission sources, in line with our international commitments. The impact of GHGs is global, and U.S. action to reduce GHG emissions

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example, because that's what the United States of America has always done." President Obama, Climate Action Plan speech, Georgetown University, 2013. Available at *https://www.whitehouse.gov/the-press-office/2013/06/25/remarks-president-climate-change*.

complements and encourages ongoing programs and efforts in other countries.

H. Legislative and Regulatory Background for CAA Section 111

In the final days of December 1970, Congress enacted sweeping changes to the Air Quality Act of 1967 to confront an "environmental crisis."[219] The Air Quality Act—which expanded federal air pollution control efforts after the enactment of the Clean Air Act of 1963—prioritized the adoption of ambient air standards but failed to target stationary sources of air pollution. As a result, "[c]ities up and down the east coast were living under clouds of smoke and daily air pollution alerts."[220] In fact, "[o]ver 200 million tons of contaminants . . . spilled into the air" each year.[221] The 1970 CAA Amendments were designed to face this crisis "with urgency and in candor." [222]

For the most part, Congress gave EPA and the states flexible tools to implement the CAA. This is best exhibited by the newly enacted programs regulating stationary sources. For these sources, Congress crafted a three-legged regime upon which

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[219] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224.

[220] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 18, 1970), 1970 CAA Legis. Hist.pa at 123.

[221] Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. These pollutants fell into five main classes of pollutants: Carbon monoxide, particulates, sulfur oxides, hydrocarbons, and nitrogen oxides. *See* Sen. Boggs, *id*. at 244.

[222] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123.

the regulation of stationary sources was intended to sit.

The first prong—CAA sections 107—110—addressed what are commonly referred to as criteria pollutants, "the presence of which in the ambient air results from numerous or diverse mobile or stationary sources" and are determined to have "an adverse effect on public health or welfare".[223] Under these provisions, states would have the primary responsibility for assuring air quality within their entire geographic area but would submit plans to the Administrator for "Implementation, maintenance, and enforcement" of national ambient air quality standards. These plans would include "emission limitations, schedules, and timetables for compliance . . . and such other measures as may be necessary to insure attainment and maintenance" of the national ambient air quality standards.[224]

The second prong—CAA section 111—addressed pollutants on a source category-wide basis. Under CAA section 111(b), the EPA lists source categories which "contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare," And then establishes "standards of performance" for the new sources in the listed

[223] "Clean Air Act Amendments of 1970," Pub. L. 91-604, § 4, 84 Stat. 1676, 1678 (Dec. 31, 1970). The "adverse effect" criterion was later amended to refer to pollutants "which may reasonably be anticipated to endanger public health or welfare". *See* 42 U.S.C. 7408(a)(1)(A). Similar language is also used under the current CAA section 111. *See* 42 U.S.C. 7411(b)(1)(A).

[224] "Clean Air Act Amendments of 1970," § 4, 84 Stat, at 1680.

category.[225] For existing sources in a listed source category, CAA section 111(d) set out procedures for the establishment of federally enforceable "emission standards" of any pollutant not otherwise controlled under the CAA's SIP provisions or CAA section 112.

Lastly, the third prong—CAA section 112—addressed hazardous air pollutants through the establishment of national "emission standards" at a level which "provides an ample margin of safety to protect the public health".[226] All new or modified sources of any hazardous air pollutant would be required to meet these emission standards. Existing sources were required to meet the same standards or would be shut down unless they obtained a temporary EPA waiver or Presidential exemption.[227]

At its inception, CAA section 111 was intended to bear a significant weight under this three-legged regime. Indeed, by 1977, the EPA had promulgated six times as many performance standards under CAA section 111 than emission standards under CAA section 112.[228] That said, states, including Texas and New Jersey, levied "substantial criticisms" against the EPA for not moving rapidly enough.[229] Accordingly, the 1977 CAA Amendments were designed to "provide a greater role for the [s]tates in standards setting under the [CAA]," "protect [s]tates from 'environmental blackmail' as they attempt to regulate

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[225] "Clean Air Act Amendments of 1970," § 4, 84 Stat, at 1684.

[226] "Clean Air Act Amendments of 1970," § 4, 84 Stat, at 1685.

[227] "Clean Air Act Amendments of 1970," § 4, 84 Stat, at 1685.

[228] H.R. Rep. No. 95-294, at 194 (May 12, 1977).

[229] H.R. Rep. No. 95-294, at 195 (May 12, 1977).

mobile and competitive industries," and lastly "provide a check on the Administrator's inaction or failure to control emissions adequately."[230]

At bottom, CAA section 111 rests on the definition of a standard of performance under CAA section 111(a)(1), which reads nearly the same now as it did when it was first adopted in the 1970 CAA Amendments. In 1970, Congress defined standard of performance—a term which had not previously appeared in the CAA—as

> 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) the Administrator determines has been adequately demonstrated.[231]

Despite significant changes to this definition in 1977, Congress reversed course in 1990 and largely reinstated the original definition.[232] As presently defined, the term applies to the regulation of new and existing sources under CAA sections 111(b) and (d).[233]

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[230] H.R. Rep. No. 95-294, at 195 (May 12, 1977).

[231] "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1683.

[232] "Clean Air Act Amendments of 1990," Pub. L. 101-549, § 403, 104 Stat. 2399, 2631 (Nov. 15, 1990) (retaining only the obligation to account for "any nonair quality health and environmental impact and energy requirements" that was added in 1977).

[233] As CAA section 111(d) was originally adopted, state plans would have established "emission standards" instead of "standards of performance." This distinction was later abandoned

The level of control reflected in the definition is generally referred to as the "best system of emission reduction," or the BSER. The BSER, however, is not further defined, and only appeared after conference between the House and Senate in late 1970, and was neither discussed in the conference report nor openly debated in either chamber. Nevertheless, the originating bills from both houses shed light on its construction.

The BSER grew out of proposed language in two bills, which, for the first time, targeted air pollution from stationary sources. The House bill sought to establish national emission standards to "prevent and control . . . emissions [of non-hazardous pollutants] to the fullest extent compatible with the available technology and economic feasibility."[234] The House also proposed to prohibit the construction or operation of new sources of "extremely hazardous" pollutants.[235] The Senate bill, on the other hand, authorized "Federal standards of performance," which would "reflect the greatest degree of emission control which the Secretary [later, the Administrator] determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives."[236] The Senate also

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in 1977 and the same term is used in both CAA sections 111(b) and (d).

[234] H.R. 17255, 91st Cong. § 5 (1970).

[235] H.R. 17255, 91st Cong. § 5 (1970).

[236] S. 4358, 91st Cong. § 6 (1970) (emphasis added). The breadth of the Senate bill is further emphasized in the conference report, which explains that a standard of performance "refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or

would have authorized "national emission standards" for hazardous air pollution and other "selected air pollution agents."[237]

After conference, CAA section 111 emerged as one of the CAA's three programs for regulating stationary sources. In defining the newly formed "standards of performance," Congress appeared to merge the various "means of preventing and controlling air pollution" under the Senate bill with the consideration of costs that was central to the House bill into the BSER. At the time, however, this definition only applied to new sources under CAA section 111(b).

To regulate existing sources, Congress collapsed section 114 of the Senate bill into CAA section 111(d).[238] Section 114 of the Senate bill established emission standards for "selected air pollution agents," and was intended to bridge the gap between criteria pollutants and hazardous air pollutants. As proposed, the Senate identified fourteen substances for regulation under section 114 and only four substances for regulation under Senate bill 4358, section 115, the predecessor of CAA section 112.[239]

As adopted, CAA section 111(d) requires states to submit plans to the Administrator establishing "emission standards" for certain existing sources of air pollutants that were not otherwise regulated as

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other methods" and also includes "other means of preventing or controlling air pollution." S. Rep. No. 91-1196, at 15–16 (Sept. 17, 1970).

[237] S. 4358, 91st Cong. § 6 (1970).

[238] The House bill did not provide for the direct regulation of existing sources.

[239] *See* S. Rep. No. 91-1196, at 18 and 20 (Sept. 17, 1970).

criteria pollutants or hazardous air pollutants. This ensured that there would be "no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."[240]

The term "emission standards," however, was not expressly defined in the 1970 CAA Amendments (save for purposes of citizen suit enforcement) even though the term was also used under the CAA's SIP provisions and CAA section 1112.[241] That said, under the newly enacted "ambient air quality and emission standards" sections, Congress directed the EPA to provide states with information "on air pollution control techniques," including data on "available technology and alternative methods of prevention and control of air pollution" and on "alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions."[242] Similarly, the Administrator would "issue information on pollution control techniques for air pollutants" in conjunction with establishing emission standards under CAA section 112. However, analogous text is absent from CAA section 111(d).

After the enactment of the 1970 CAA Amendments, the EPA proposed standards of performance for an "initial list of five stationary source categories which

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[240] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970) (discussing the relationship between sections 114 (addressing emission standards for "selected air pollution agents") and 115 (addressing hazardous air pollutants) of the Senate bill).

[241] *See* "Clean Air Act Amendments of 1970," § 12, 84 Stat, at 1706.

[242] "Clean Air Act Amendments of 1970," § 4, 84 Stat, at 1679.

contribute significantly to air pollution" in August 1971.[243] The first category listed was for fossil-fuel fired steam generators, for which EPA proposed and promulgated standards for particulate matter, SO_2, and NO_X.[244] Several years later, the EPA proposed its implementing regulations for CAA section 111(d).[245] These regulations were finalized in November 1975, and provided for the publication of emission guidelines.[246] The first emission guidelines were proposed in May 1976 and finalized in March 1977.[247]

Despite these first steps taken under CAA sections 111(b) and (d), Congress revisited the CAA in 1977 to address growing concerns with the nation's response to the 1973 oil embargo (noted above), to respond to new environmental problems such as stratospheric ozone depletion, and to resolve other issues associated with implementing the 1970 CAA Amendments.[248]

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[243] "Standards of Performance for New Stationary Sources: Proposed Standards for Five Categories," 36 FR 15704 (Aug. 17, 1971). *See* "Clean Air Act Amendments of 1970," § 4, 84 Stat. at 1684 (requiring the Administrator to publish a list of categories of stationary sources within 90 days of the enactment of the 1970 CAA Amendments).

[244] 36 FR at 15704–706; and "Standards of Performance for New Stationary Sources," 36 FR 24876, 24879 (Dec. 23, 1971).

[245] *See* "State Plans for the Control of Existing Facilities," 39 FR 36102 (Oct. 7, 1974).

[246] *See* "State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340 (Nov. 17, 1975).

[247] *See* "Phosphate Fertilizer Plants; Draft Guideline Document; Availability," 41 FR 19585 (May 12, 1976); and "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977).

[248] For example, Congress recognized that many air pollutants had not been regulated despite "mounting evidence" that these

Most notably, an increase in coal use as a result of the oil crisis meant that "vigorous and effective control" of air emissions was "even more urgent."[249] Thus, to curb the projected surge in air emissions, Congress enacted several new provisions to the CAA. These new provisions include the prevention of significant deterioration (PSD) program, visibility protections, and requirements for nonattainment areas.[250]

Congress also made significant changes to CAA section 111. For example, Congress amended the definition of a standard of performance (including by requiring the consideration of "nonair quality health and environmental impact and energy requirements"), authorized alternative (*e.g.*, work practice or design) standards in limited circumstances, provided states

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pollutants "are associated with serious health hazards". H.R. Rep. No. 94-1175, 22 (May, 15, 1976). Because EPA "failed to promulgate regulations to institute adequate control measures," Congress ordered EPA to regulate four specific pollutants that had "been found to be cancer-causing or cancer-promoting". *Id.* at 23. This directive, reflected in CAA section 122, specifically added radioactive pollutants, cadmium, arsenic, and polycyclic organic matter "under the various provisions of the Clean Air Act and allows their regulation as criteria pollutants under ambient air quality standards, as hazardous air pollutants, or under new source performance standards, as appropriate." H.R. Conf. Rep. No. 95-564, 142 (Aug. 3, 1977), 1977 CAA Legis. Hist. at 522. At the same time, Congress made sure that these commands would have no effect on the Administrator's discretion to address "any substance (whether or not enumerated (under CAA section 122(a))" under CAA sections 108, 112, or 111. 42 U.S.C. 7422(b).

[249] *See* Statement of EPA Administrator Costle, S. Hearings on S. 272, S. 273, S. 977, and S. 1469 (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532.

[250] *See* "Clean Air Act Amendments of 1977," Pub. L. 95-95, §§ 127–129, 91 Stat. 685 (Aug. 7, 1977).

with authority to petition the Administrator for new or revised (and more stringent) standards, and imposed a strict regulatory schedule for establishing standards of performance for categories of major stationary sources that had not yet been listed.[251]

The 1977 definition for a standard of performance required "all new sources to meet emission standards based on the reductions achievable through the use of the 'best technological system of continuous emission reduction.'"[252] For fossil-fuel fired stationary sources, Congress further required a percentage reduction in emissions from the use of fuels.[253] Together, this was designed to "force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance."[254]

Congress also clarified that with respect to CAA section 111(d), standards of performance (now applicable in lieu of emission standards) "would be

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[251] "Clean Air Act Amendments of 1977," § 109, 91 Stat, at 697.

[252] H.R. Rep. No. 95-294, at 192 (May 12, 1977). Congress separately defined "technological system of continuous emission reduction" as "(A) a technological process for production or operation by any source which is inherently low-polluting or nonpolluting, or (B) technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels." "Clean Air Act Amendments of 1977," § 109, 91 Stat, at 700; *see also* 42 U.S.C. 7411(a)(7).

[253] "Clean Air Act Amendments of 1977," § 109, 91 Stat, at 700.

[254] "New Stationary Sources Performance Standards; Electric Utility Steam Generating Units," 44 FR 33580, 33581–82 (June 11, 1979).

based on the best available means (not necessarily technological)".[255] This was intended to distinguish existing source standards from new source standards, for which "the requirement for [the BSER] has been more narrowly redefined as best technological system of continuous emission reduction."[256] Additionally, Congress clarified that states could consider "the remaining useful life" of a source when applying a standard of performance to a particular existing source.[257]

In the twenty years since the 1970 CAA Amendments and in spite of the refinements of the 1977 CAA Amendments, "many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious."[258] Indeed, in 1989, President George Bush said that "'progress has not come quickly enough and much remains to be done.'"[259] This time, with the 1990 CAA Amendments, Congress substantially overhauled the CAA. In particular, Congress again added to the NAAQS program, completely revised CAA section 112, added a new title to target existing fossil fuel-fired stationary sources and address growing concerns with acid rain, imported an operating permit modeled off the Clean

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[255] H.R. Rep. No. 95-294, at 195 (May 12, 1977).

[256] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

[257] This concept was already reflected in the EPA's CAA section 111(d) implementing regulations under 40 CFR 60.24(f). *See* 40 FR 53340, 53347 (Nov. 17, 1975).

[258] H.R. Rep. No. 101-490, at 144 (May 17, 1990).

[259] H.R. Rep. No. 101-490, at 144 (May 17, 1990).

Water Act, and established a phase out of certain ozone depleting substances.

All told, however, there was minimal debate on changes to CAA section 111. In fact, the only discussion centered on the repeal of the percentage reduction requirement, which became seen as unduly restrictive. Accordingly, Congress reverted the definition of "standard of performance" to the definition agreed to in the 1970 CAA Amendments, but retained the requirement to consider nonair quality environmental impacts and energy requirements added in 1977.[260] However, the repeal would only apply so long as the SO_2 cap under CAA section 403(e) of the newly established acid rain program remained in effect.[261] Lastly, Congress instructed the EPA to revise its new source performance standards for SO_2 emissions from fossil fuel-fired power plants but required that the revised emission rate be no less stringent than before.[262]

I. *Statutory and Regulatory Requirements*

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of

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[260] Congress also updated the regulatory schedule that was added in the 1977 CAA Amendments to reflect the newly enacted 1990 CAA Amendments. *See* "Clean Air Act Amendments of 1990," § 108, 104 Stat. 2467.

[261] "Clean Air Act Amendments of 1990," § 403, 104 Stat, at 2631.

[262] "Clean Air Act Amendments of 1990," § 301, 104 Stat, at 2631.

stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[263] The EPA has listed more than 60 stationary source categories under this provision.[264] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source categories.[265] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for HAP. CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.

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[263] CAA section 111(b)(1)(A).

[264] *See* 40 CFR 60 subparts Cb—OOOO.

[265] CAA section 111(b)(1)(B), 111(a)(1).

"Standards of performance" are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." CAA section 111(d)(1) grants states the authority, in applying a standard of performance to a particular source, to take into account the source's remaining useful life or other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is "satisfactory."[266] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[267] Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under the Act.

Section 302(d) of the CAA defines the term "state" to include the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa and the Commonwealth of the Northern Mariana Islands. While 40 CFR part 60 contains a separate definition of "state" at section 60.2, this definition expands on, rather than narrows, the definition in section 302(d) of the CAA. The introductory language to 40 CFR 60.2 provides: "The terms in this part are defined in the Act or in this section as follows." Section 60.2 defines

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[266] CAA section 111(d)(2)(A).

[267] CAA section 111(d)(2)(A).

"State" as "all non-Federal authorities, including local agencies, interstate associations, and State-wide programs that have been delegated authority to implement: (1) The provisions of this part and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context." The EPA believes that the last sentence refers to the conventional meaning of "state" under the CAA. Thus, the EPA believes the term "state" as used in the emission guidelines is most reasonably interpreted as including the meaning ascribed to that term in section 302(d) of the CAA, which expressly includes U.S. territories.

Section 301(d)(A) of the CAA recognizes that the American Indian tribes are sovereign Nations and authorizes the EPA to "treat tribes as States under this Act". The Tribal Authority Rule (63 FR 7254, February 12, 1998) identifies that EPA will treat tribes in a manner similar to states for all of the CAA provisions with the exception of, among other things, specific plan submittal and implementation deadlines under the CAA. As a result, though they operate as part of the interconnected system of electricity production and distribution, affected EGUs located in Indian country would not be encompassed within a state's CAA section 111(d) plan. Instead, an Indian tribe with one or more affected EGUs located in its area of Indian country[268] 268 will have the opportunity,

[268] The EPA is aware of at least four affected sources located in Indian Country: Two on Navajo lands—the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands—the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the

but not the obligation, to apply for eligibility to develop and implement a CAA section 111(d) plan. The Indian tribe would need to be approved by the EPA as eligible to develop and implement a CAA section 111(d) plan following the procedure set forth in 40 CFR part 49. Once a tribe is approved as eligible for that purpose, it would be treated in the same manner as a state, and references in the emission guidelines to states would refer equally to the tribe. The EPA notes that, while tribes have the opportunity to apply for eligibility to administer CAA programs, they are not required to do so. Further, the EPA has established procedures in 40 CFR part 49 (see particularly 40 CFR 49.7(c)) that permit eligible tribes to request approval of reasonably severable partial program elements. Those procedures are applicable here.

In these final emission guidelines, the term “state” 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 to develop and implement a CAA section 111(d) plan.

The EPA issued regulations implementing CAA section 111(d) in 1975,[269] and has revised them in the years since.[270] (We refer to the regulations generally as the implementing regulations.) These regulations provide that, in promulgating requirements for

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first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[269] “State Plans for the Control of Certain Pollutants from Existing Facilities,” 40 FR 53340 (Nov. 17, 1975).

[270] The most recent amendment was in 77 FR 9304 (Feb. 16, 2012).

sources under CAA section 111(d), the EPA first develops regulations known as "emission guidelines," which establish binding requirements that states must address when they develop their plans.[271] The implementing regulations also establish timetables for state and EPA action: States must submit state plans within 9 months of the EPA's issuance of the guidelines,[272] and the EPA must take final action on the state plans within 4 months of the due date for those plans,[273] although the EPA has authority to extend those deadlines.[274] In this rulemaking, the EPA is following the requirements of the implementing regulations, and is not re-opening them, except that the EPA is extending the timetables, as described below.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (*i.e.*, sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[275] In addition, the agency has

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[271] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term "emission guidelines"—instead of emissions limitations—to make clear that guidelines would not be binding requirements applicable to the sources, but instead are "criteria for judging the adequacy of State plans." 40 FR at 53343.

[272] 40 CFR 60.23(a)(1).

[273] 40 CFR 60.27(b).

[274] *See* 40 CFR 60.27(a).

[275] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp

regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[276] The agency has not previously regulated CO_2 or any other GHGs under CAA section 111(d).

The EPA's previous CAA section 111(d) actions were necessarily geared toward the pollutants and industries regulated. Similarly, in this rulemaking, in defining CAA section 111(d) emission guidelines for the states and determining the BSER, the EPA believes that taking into account the particular characteristics of carbon pollution, the interconnected nature of the power sector and the manner in which EGUs are currently operated is warranted. Specifically, the operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO_2 reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness. These

Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

[276] *See, e.g.*, "Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule," 76 FR 15372 (Mar. 21, 2011).

opportunities exist in the utility power sector in ways that were not relevant or available for other industries for which the EPA has established CAA section 111(d) emission guidelines.[277]

In this action, the EPA is promulgating emission guidelines for states to follow in developing their CAA section 111(d) plans to reduce emissions of CO_2 from the utility power sector.

J. Clean Power Plan Proposal and Supplemental Proposal

On June 18, 2014, the EPA proposed emission guidelines for states to follow in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the EPA proposed rate-based goals for CO_2 emissions for each state with existing fossil fuel-fired EGUs, as well as guidelines for plans to achieve those goals. On November 4, 2014, the EPA published a supplemental proposal that proposed emission rate-based goals for CO_2 emissions for U.S. territories and areas of Indian country with existing fossil fuel-fired EGUs. In the supplemental proposal, the EPA also solicited comment on authorizing jurisdictions (including any states, territories and areas of Indian country) without

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[277] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

existing fossil fuel-fired EGUs subject to the proposed emission guidelines to partner with jurisdictions (including any states) that do have existing fossil fuel-fired EGUs subject to the proposed emission guidelines in developing multi-jurisdictional plans. The EPA also solicited comment on the treatment of RE, demand-side EE and other new low- or zero-emitting electricity generation across international boundaries in a state plan.

The EPA also issued two documents after the June 18, 2014 proposal. On October 30, 2014, the EPA published a NODA in which the agency provided additional information on several topics raised by stakeholders and solicited comment on the information presented. This action covered three topic areas: 1) the emission reduction compliance trajectories created by the interim goal for 2020 to 2029, 2) certain aspects of the building block methodology, and 3) the way state-specific CO_2 goals are calculated.

In a separate action, the EPA published a document regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal (79 FR 67406; November 13, 2014). With the action, the EPA also made available, in the docket for this rulemaking, a TSD that provided two examples of how a state, U.S. territory or tribe could translate a rate-based CO_2 goal to total metric tons of CO_2 (a mass-based equivalent).

K. Stakeholder Outreach and Consultations

Following the direction in the Presidential Memorandum to the Administrator (June 25, 20'13),[278] the EPA engaged in extensive and vigorous outreach to stakeholders and the general public at every stage of development of this rule. Our outreach has included direct engagement with the energy and environment officials in states, tribes, and a full range of stakeholders including leaders in the utility power sector, labor leaders, non-governmental organizations, other federal agencies, other experts, community groups and members of the public. The EPA participated in more than 300 meetings before the rule was proposed and more than 300 after the proposal.

Throughout the rulemaking process, the agency has encouraged, organized, and participated in hundreds of meetings about CAA section 111(d) and reducing carbon pollution from existing power plants. The agency's outreach prior to proposal, as well as during the public comment period, was designed to solicit policy ideas,[279] concerns, and technical information. The agency received 4.3 million comments about all aspects of the proposed rule and thousands of people participated in the agency's public hearings, webinars,

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

[279] The EPA received more than 2,000 emails offering input into the development of these guidelines through email and a Web-based form. These emails and other materials provided to the EPA are posted on line as part of a non-regulatory docket, EPA Docket ID No. EPA-HQ-OAR-2014-0020, at *www.regulations.gov*.

listening sessions,[280] teleconferences and meetings held all across the country.

Our engagement has brought together a variety of states and stakeholders to discuss a wide range of issues related to the utility power sector and the development of emission guidelines under CAA section 111(d). The meetings were attended by the EPA Regional Administrators, other senior managers and staff who have been instrumental in the development of the rule and will play key roles in developing and implementing it.

This outreach process has produced a wealth of information which has informed this rule significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialogue with states and stakeholders will continue after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the states will play in addressing carbon pollution from power plants. We firmly believe that our outreach has resulted in a more workable rule that will achieve the statutory goals and has enhanced the likelihood of timely and successful achievement of the carbon reduction goals, given the critical importance and urgency of the concrete action.

The EPA has given stakeholder comments careful consideration and, as a result, this final rule includes

[280] Summaries of the 11 public listening sessions in 2013 are available at *www.regulations.gov* at EPA Docket ID No. EPA-HQ-OAR-2014-0020.

features that are responsive to many stakeholder concerns.

1. Public Hearings

More than 2,700 people attended the public hearings sessions held in Atlanta, Denver, Pittsburgh, and Washington, DC. More than 1,300 people spoke at the public hearings. Additionally, about 100 people attended the public hearing held in Phoenix, Arizona, on the November 4, 2014 supplemental proposal. Speakers at the public hearings included Members of Congress, other public officials, industry representatives, faith-based organizations, unions, environmental groups, community groups, students, public health groups, energy groups, academia and concerned citizens.

Participants shared a range of perspectives. Many were concerned with the impacts of climate change on their health and on future generations, others were worried about the impact of regulations on the economy. Their support for the agency's efforts varied.

2. State Officials

Since fall 2013, the agency has provided multiple opportunities for the states to inform this rulemaking. Administrator McCarthy has engaged with governors from states with a variety of interests in the rulemaking. Other senior agency officials have engaged with every branch and major agency of state government—including state legislators, attorneys general, state energy, environment, and utility officials, and governors' staff.

On several occasions, state environmental commissioners met with senior agency officials to provide comments on the Clean Power Plan. The EPA organized, encouraged and attended meetings with states to discuss multi-state planning efforts. States have come together with several collaborative groups to discuss ways to work together to make the Clean Power Plan more affordable. The EPA has participated in and supported the states in these discussions. Because of the interconnectedness of the power sector, and the fact that electricity generated at power plants crosses state lines; states, utilities and ratepayers may benefit from states working together to implement the requirements of this rulemaking. The meetings provided state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with the EPA officials. In addition, the states submitted public comments from several agencies within each state. The wealth of comments and input from states was important in developing the final rulemaking.

Agency officials listened to ideas, concerns and details from states, including from states with a wide range of experience in reducing carbon pollution from power plants. The EPA reached out to all 50 states to engage with both environmental and energy departments at all levels of government. As an example, a three-part webinar series in June/July 2014 for the states and tribes offered an interactive format for technical staff at the EPA and in the states/tribes to exchange ideas and ask clarifying question. The webinars were then posted online so other stakeholders could view them. A few weeks after the postings, the EPA organized follow-up conference calls with stakeholder groups. Also, the EPA hosted scores of technical meetings between states and the

EPA in the weeks and months after the rule was proposed.

Additionally, the EPA organized "hub" calls; these teleconferences brought all of the states in a given EPA region together to discuss technical and interstate aspects of the proposal. These exchanges helped provide the stakeholders with the information they needed to comment on the proposal effectively. The EPA also held a series of webinars with state environmental associations and their members on a series of technical issues.

The agency has collected policy papers and comment letters from states with overarching energy goals and technical details on the states' utility power sector. EPA leadership and staff also participated in webinars and meetings with state and tribal officials hosted by collaborative groups and trade associations. After the comment period closed, and based on our meetings over the last year, as well as written comments on the proposal and NODA, the EPA analyzed information about data errors that needed to be addressed for the final rule. In February and March 2015, we reached out to particular states to clarify ambiguous or unclear information that was submitted to the EPA related to NEEDS and eGRID data. The EPA contacted particular states to clarify the technical comments or concerns to ensure that any changes we make are accurate and appropriate.

To help prepare for implementation of this rule, the agency initiated several outreach activities to assist with state planning efforts. The agency participated in meetings organized by the National Association of State Energy Officials (NASEO), the National

Association of Regulatory Utility Commissioners (NARUC), and the National Association of Clean Air Agencies (NACAA) (the "3N" groups). Meeting participants discussed issues related to EE and RE.

To help state officials prepare for the planning process that will take place in the states, the EPA presented a webinar on February 24, 2015. This webinar provided an update on training plans and further connection with states in the implementation process. Forty-nine states, the District of Columbia, and 14 tribes were represented at this webinar. The EPA is developing a state plan electronic collection system to receive, track, and store state submittals of plans and reports. The EPA plans to use an integrated project team to solicit stakeholder input on the system during development. The team membership, including state representatives, will bring together the business and technology skills required to construct a successful product and promote transparency in the EPA's implementation of the rule.

To help identify training needs for the final Clean Power Plan, the agency reached out to a number of state and local organizations such as the Central State Air Resources Agencies and other such regional air agencies. The EPA's outreach on training has included sharing the plans with the states and incorporating changes to the training topics based on the states' needs. The EPA training plan includes a wide variety of topics such as basic training on the electric power sector as well as specific pollution control strategies to reduce carbon emissions from power plants. In particular, the states requested training on how to use programs such as combined heat and power, EE and RE to reduce carbon emissions. The EPA will continue to work with states to tailor training activities to their needs.

The agency has engaged, and will continue to engage with states, territories, Washington, DC, and tribes after the rulemaking process and throughout implementation.

3. Tribal Officials

The EPA conducted significant outreach to and consultation with tribes. Tribes are not required to, but may, develop or adopt Clean Air Act programs. The EPA is aware of four facilities with affected EGUs located in Indian country: the South Point Energy Center, in Fort Mojave Indian country, geographically located within Arizona; the Navajo Generating Station, in Navajo Indian country, geographically located within Arizona; the Four Corners Power Plant, in Navajo Indian country, geographically located within New Mexico; and the Bonanza Power Plant, in Ute Indian country, geographically located within Utah. The EPA offered consultation to the leaders of the tribes on whose lands these facilities are located as well as all of the federally recognized tribes to ensure that they had the opportunity to have meaningful and timely input into this rule. Section III ("Stakeholder Outreach and Conclusions") of the June 18, 2014 proposal documents the EPA's extensive outreach efforts to tribal officials prior to that proposal, including an informational webinar, outreach meeting, teleconferences with tribal officials and the National Tribal Air Association (NTAA), and letters offering consultation. Additional outreach to tribal officials conducted by the EPA prior to the November 4, 2014 supplemental proposal is discussed in Section II.D

("Additional Outreach and Consultation") of the supplemental proposal. The additional outreach for the supplemental proposal included consultations with all three tribes that have affected EGUs on their lands, as well as several other tribes that requested consultation, and also additional teleconferences with the NTAA.

After issuing the supplemental proposal, the EPA offered an additional consultation to the leaders of all federally recognized tribes. The EPA held an informational meeting open to all tribes and also held consultations with the Navajo Nation, Fort McDowell Yavapai Nation, Fort Mojave Tribe, Ak-Chin Indian Community, and Hope Tribe on November 18, 2014. The EPA held a consultation with the Ute Tribe of the Uintah and Ouray Reservation on December 16, 2014, and a consultation with the Gila River Indian Community on January 15, 2015. The EPA held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. On April 28, 2015, the EPA held an additional consultation with the Navajo Nation.

Tribes were interested in the impact of this rule on other ongoing regulatory actions at the affected EGUs, such as permitting or requirements for the best available retrofit technology (BART). Tribes also noted that it was important to allow RE projects on tribal lands to contribute toward meeting state goals. Some tribes indicated an interest in being involved in the development of implementation plans for areas of Indian country. Additional detail regarding the EPA's outreach to tribes and comments and recommendations from tribes can be found in Section X.F of this preamble.

4. U.S. Territories

The EPA has met with individual U.S. territories and affected EGUs in U.S. territories during the rulemaking process. On July 22, 2014, the EPA met with representatives from the Puerto Rico Environmental Quality Board, the Puerto Rico Electric Power Authority, the Governor's Office, and the Office of Energy, Puerto Rico. On September 8, 2014, the EPA held a meeting with representatives from the Guam Environmental Protection Agency (GEPA) and the Guam Power Authority and, on February 18, 2015, the EPA met again with representatives from GEPA.

5. Industry Representatives

Agency officials have engaged with industry leaders and representatives from trade associations in many one-on-one and national meetings. Many meetings occurred at the EPA headquarters and in the EPA's Regional Offices and some were sponsored by stakeholder groups. Because the focus of the rule is on the utility power sector, many of the meetings with industry have been with utilities and industry representatives directly related to the utility power sector. The agency has also met with energy industries such as coal and natural gas interests, as well as companies that offer new technology to prevent or reduce carbon pollution, including companies that have expertise in RE and EE. Other meetings have been held with representatives of energy intensive industries, such as the iron and steel and aluminum industries, to help understand the issues related to large industrial users of electricity.

6. Electric Utility Representatives

Agency officials participated in many meetings with utilities and their associations to discuss all aspects of the proposed guidelines. We have met with all types of companies that produce electricity, including private utilities or investor owned utilities. Public utilities and cooperative utilities were also part of in-depth conversations about CAA section 111(d) with EPA officials.

The conversations included meetings with the EPA headquarters and regional offices. State officials were included in many of the meetings. Meetings with utility associations and groups of utilities were held with key EPA officials. The meetings covered technical, policy and legal topics of interest and utilities expressed a wide variety of support and concerns about CAA section 111(d).

7. Electricity Grid Operators

The EPA had a number of conversations with the ISOs and RTOs to discuss the rule and issues related to grid operations and reliability. EPA staff met with the ISO/RTO Council on several occasions to collect their ideas. The EPA regional offices also met with the ISOs and RTOs in their regions. System operators have offered suggestions in using regional approaches to implement CAA section 111(d) while maintaining reliable, affordable electricity.

8. Representatives from Community and Non-governmental Organizations

Agency officials engaged with community groups representing vulnerable communities, and faith-based groups, among others, during the outreach effort. In response to a request from communities, the EPA held a day-long training on the Clean Power Plan on October 30, 2014, in Washington DC At this meeting, the EPA met with a number of environmental groups to provide information on how the agency plans on reducing carbon pollution from existing power plants using CAA section 111(d).

Many environmental organizations discussed the need for reducing carbon pollution. Meetings were technical, policy and legal in nature and many groups discussed specific state policies that are already in place to reduce carbon pollution in the states.

A number of organizations representing religious groups have reached out to the EPA on several occasions to discuss their concerns and ideas regarding this rule. Many members of faith communities attended the four public hearings.

Public health groups discussed the need for protection of children's health from harmful air pollution. Doctors and health care providers discussed the link between reducing carbon pollution and air pollution and public health. Consumer groups representing advocates for low income electricity customers discussed the need for affordable electricity. They talked about reducing electricity prices for consumers through EE and low-cost carbon reductions.

In winter/spring 2015, EPA continued to offer webinars and teleconferences for community groups on the rulemaking.

9. Environmental Justice Organizations

Agency officials engaged with environmental justice groups representing communities of color, low-income communities and others during the outreach effort. Agency officials also engaged with the EPA's National

Environmental Justice Advisory Council (NEJAC) members in September 2013. The NEJAC is composed of stakeholders, including environmental justice leaders and other leaders from state and local government and the private sector. Additionally, the agency conducted a community call on February 26, 2015, and on February 27, 2015, the EPA conducted a follow up webinar for participants in an October 30, 2014 training session. The EPA also held a webinar for communities on the Clean Air Act (CAA) and section 111(d) of the CAA on April 2, 2015. The agency, in partnership with FERC and DOE, held two additional webinars for communities on the electricity grid and on energy markets on June 11, 2015, and July 9, 2015.

During the EPA's extensive outreach conducted before and after proposal, the EPA has heard a variety of issues raised by environmental justice communities. Communities expressed the desire for the agency to conduct an environmental justice (EJ) analysis and to require that states in the development of their state plans conduct one as well. Additionally, they asked that the agency require that states engage with communities in the development of their state plans and that the agency conduct meaningful involvement with communities, throughout the whole rulemaking process, including the implementation phase. Furthermore, communities stressed the importance of low-income and communities of color receiving the benefits of this rulemaking and being protected from being adversely impacted by this rulemaking.

The purpose of this rule is to substantially reduce emissions of CO_2, a key contributor to climate change, which adversely and disproportionately affects vulnerable and disadvantaged communities in the U.S. and around the world. In addition, the rule will result in substantial reductions of conventional air pollutants, providing immediate public health benefits to the communities where the facilities are located and for many miles around. The EPA is committed to ensuring that all Americans benefit from the public health and other benefits that this rule will bring. Further discussion of the impacts of this rule on vulnerable communities and actions that the EPA is taking to address concerns cited by communities is available in Sections IX and XII.J of this preamble.

10. Labor

Senior agency officials met with a number of labor union representatives about reducing carbon pollution using CAA section 111(d). Those unions included: The United Mine Workers of America; the Sheet Metal, Air, Rail and Transportation Union (SMART); the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers (IBB); United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada; the International Brotherhood ofElectrical Workers (IBEW); and the Utility Workers Union of America. In addition, agency leaders met with the Presidents of several unions and the President of the American Federation of Labor-Congress of Industrial Organizations (AFL-CIO) at the AFL-CIO headquarters.

EPA officials attended meetings sponsored by labor unions to give presentations and engage in discussions about reducing carbon pollution using CAA section

111(d). These included meetings sponsored by the IBB and the IBEW.

11. Other Federal Agencies and Independent Agencies

Throughout the development of the rulemaking, the EPA consulted with other federal agencies with relevant expertise. For example, the EPA met with managers from the U.S. Department of Agriculture's (USDA's) Rural Utility Service to discuss the rule and potential effects on affected EGUs in rural areas and how USDA programs could interact with affected EGUs during rule implementation.

The U.S. Department of Energy (DOE) was a frequent source of expertise on the proposed and final rule. EPA management and staff had numerous meetings with management and staff at DOE on a range of topics, including the effectiveness and costs of energy generation technologies, and EE.

DOE provided technical assistance relating to RE and demand-side EE, including RE and demand-side EE cost and performance data and, for RE, information on the feasibility of deploying and reliably integrating increased RE generation. Further, EPA and DOE staff discussed emission measurement and verification (EM&V) strategies.

The EPA also consulted with DOE on electric reliability issues. EPA staff and managers met and spoke with DOE staff and managers throughout the development of the proposed and final rules on topic related to electric system reliability.

EPA officials worked closely with DOE and Federal Energy Regulatory Commission (FERC) officials to ensure, to the greatest extent possible, that actions taken by states and affected EGUs to comply with the final rule mitigate potential electric system reliability issues. Senior EPA officials met with each of the FERC Commissioners and EPA staff had frequent contact with FERC staff throughout the development the rule. FERC held four technical conferences to discuss implications of compliance approaches to the rule for electric reliability. EPA staff attended the four conferences and EPA leadership spoke at all of them. The EPA, DOE, and FERC will continue to work together to ensure electric grid reliability in the development and implementation of state plans.

L. Comments on the Proposal

The Administrator signed the proposed emission guidelines on June 2, 2014, and, on the same day, the EPA made this version available to the public at *http://www.epa.gov/cleanpowerplan/*. The 120-day public comment period on the proposal began on June 18, 2014, the day of publication of the proposal in the **Federal Register**. On September 18, 2014, in response to requests from stakeholders, the EPA extended the comment period by 45 days, to December 1, 2014, giving stakeholders over 165 days to review and comment upon the proposal. Stakeholders also had the opportunity to comment on the NODA, as well as the **Federal Register** document and TSD regarding potential methods for determining the mass that is equivalent to an emission rate-based CO_2 goal, through December 1, 2014. The EPA offered a separate 45-day comment period for the November 4, 2014 supplemental proposal, and that comment period closed on December 19, 2014.

The EPA received more than 4.2 million comments on the proposed carbon pollution emission guidelines from a range of stakeholders that included, including state environmental and energy officials, local government officials, tribal officials, public utility commissioners, system operators, utilities, public interest advocates, and members of the public. The agency received comments on many aspects of the proposal and many suggestions for changes that would address issues of concern.

III. Rule Requirements and Legal Basis

A. Summary of Rule Requirements

The EPA is establishing emission guidelines for states to use in developing plans to address GHG emissions from existing fossil fuel-fired electric generating units. The emission guidelines are based on the EPA's determination of the "best system of emission reduction . . . adequately demonstrated" (BSER) and include source category-specific CO_2 emission performance rates, state-specific goals, requirements for state plan components, and requirements for the process and timing for state plan submittal and compliance.

Under CAA section 111(d), the states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the "best system of emission reduction" that, 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.

The EPA has determined that the BSER is the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through the following three sets of measures or building blocks:

1. Improving heat rate at affected coal-fired steam EGUs.

2. Substituting increased generation from lower-emitting existing natural gas combined cycle units for generation from higher-emitting affected steam generating units.

3. Substituting increased generation from new zero-emitting RE generating capacity for generation from affected fossil fuel-fired generating units.

Consistent with CAA section 111(d) and other rules promulgated under this section, the EPA is taking a traditional, performance-based approach to establishing emission guidelines for affected sources and applying the BSER to two source subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines. The EPA is finalizing source subcategory-specific emission performance rates that reflect the EPA's application of the BSER. For fossil fuel-fired steam generating units, we are finalizing a performance rate of 1,305 lb CO_2/MWh. For stationary combustion turbines, we are finalizing a performance rate of 771 CO_2/MWh. The EPA has also translated the source subcategory-specific CO_2 emission performance rates into equivalent statewide rate-based and mass-based CO_2 goals and is providing those as an option for states to use.

Under CAA section 111(d), each state must develop, adopt, and then submit its plan to the EPA. For its CAA section 111(d) plan, a state will determine whether to apply these emission performance rates to each affected EGU, individually or together, or to take an alternative approach and meet either an equivalent statewide rate-based goal or an equivalent statewide mass-based goal, as provided by the EPA in this rulemaking.

States with one or more affected EGUs will be required to develop and implement plans that set emission standards for affected EGUs. The CAA section 111(d) emission guidelines that the EPA is promulgating in this action apply to only the 48 contiguous states 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.[281] Because Vermont and the District of Columbia do not have affected EGUs, they will not be required to submit a state plan. Because the EPA does not possess all of the information or analytical tools needed to quantify the BSER for the two non-contiguous states with otherwise affected EGUs (Alaska and Hawaii) and the two U.S. territories with otherwise affected EGUs (Guam and Puerto Rico), these emission guidelines do not apply to those areas,

[281] In the case of a tribe that has one or more affected EGUs in its area of Indian country, the tribe has the opportunity, but not the obligation, to establish a CO_2 emission standard for each affected EGU located in its area of Indian country and a CAA section 111(d) plan for its area of Indian country. If the tribe chooses to establish its own plan, it must seek and obtain authority from the EPA to do so pursuant to 40 CFR 49.9. If it chooses not to seek this authority, the EPA has the responsibility to determine whether it is necessary or appropriate, in order to protect air quality, to establish a CAA section 111(d) plan for an area of Indian country where affected EGUs are located.

and those areas will not be required to submit state plans on the schedule required by this final action.

In developing its CAA section 111(d) plan, a state will have the option of choosing from two different approaches: (1) An "emission standards" approach, or (2) a "state measures" approach. With an emission standards approach, a state will apply all requirements for achieving the subcategory-specific CO_2 emission performance rates or the state-specific CO_2 emission goal to affected EGUs in the form of federally enforceable emission standards. With a state measures approach, a state plan would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, along with a backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of CO_2 emission performance.

The EPA is requiring states to make their final plan submittals by September 6, 2016, or to make an initial submittal by this date in order to obtain an extension for making their final plan submittals no later than September 6, 2018, which is 3 years from the signature date of the rule. In order to receive an extension, states, in the initial submittal, must address three required components sufficiently to demonstrate that a state is able to undertake steps and processes necessary to timely submit a final plan by the extended date of September 6, 2018. The first required component is identification of final plan approach or approaches under consideration, including a description of progress made to date. The second required component is an appropriate explanation for why the state requires additional time to submit a final plan beyond September 6, 2016. The third required component for states to address in the initial submittal is a demonstration of how they have been engaging with the public, including vulnerable communities, and a description of how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan.

Affected EGUs must achieve the final emission performance rates or equivalent state goals by 2030 and maintain that level thereafter. The EPA is establishing an 8-year interim period over which states must achieve the full required reductions to meet the CO_2 performance rates, and this begins in 2022. This 8-year interim period from 2022 through 2029, is separated into three steps, 2022–2024, 2025–2027, and 2028–2029, each associated with its own interim CO_2 emission performance rates that states must meet, as explained in Section VI of this preamble.

For the final emission guidelines, the EPA is revising the list of components required in a final state plan submittal to reflect: (1) Components required for all state plan submittals; (2) components required for the emission standards approach; and (3) components required for the state measures approach. The revised list of components also reflects the approvability criteria, which are no longer separate from the state plan submittal components.

All state plans must include the following components:

- Description of the plan approach and geographic scope

- Identification of the state's CO_2 interim period goal (for 2022–2029), interim steps (interim step goal 1 for 2022–2024; interim step goal 2 for 2025–2027; interim step goal 3 for 2028–2029) and final CO_2 emission goal of 2030 and beyond
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission goal[282]
- State recordkeeping and reporting requirements
- Certification of hearing on state plan
- Supporting documentation

Also, in all state plans, as part of the supporting documentation, a state must include a description of how they considered reliability in developing its state plan.

State plan submittals using the emission standards approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for the affected EGUs; and monitoring, recordkeeping and reporting requirements.
- Demonstrations that each emission standard will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

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[282] A state that chooses to set emission standards that are identical to the emission performance rates for both the interim period and in 2030 and beyond need not identify interim state goals nor include a separate demonstration that its plan will achieve the state goals.

State plan submittals using the state measures approach must also include:

- Identification of each affected EGU; identification of federally enforceable emission standards for affected EGUs (if applicable); identification of backstop of federally enforceable emission standards; and monitoring, recordkeeping and reporting requirements.

- Identification of each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

In addition to these requirements, each state plan must follow the EPA implementing regulations at 40 CFR 60.23.

If a state with affected EGUs does not submit a plan or if the EPA does not approve a state's plan, then under CAA section 111(d)(2)(A), the EPA must establish a plan for that state. A state that has no affected EGUs must document this in a formal negative declaration submitted to the EPA by September 6, 2016. In the case of a tribe that has one or more affected EGUs in its area of Indian country,[283] the tribe has the opportunity, but not the obligation, to establish a CAA section 111(d) plan for its area of Indian country. If a tribe with one or more affected

[283] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Power Plant; one on Ute lands, the Bonanza Power Plant; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

EGUs located in its area of Indian country does not submit a plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate.

During implementation of its approved state plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements. State plan requirements and flexibilities are described more fully in Section VIII of this preamble.

B. Brief Summary of Legal Basis

This rule is consistent with the requirements of CAA section 111(d) and the implementing regulations.[284] As an initial matter, the EPA

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[284] Under CAA section there is no requirement that the EPA make a finding that the emissions from existing sources that are the subject of regulation cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. As predicates to promulgating regulations under CAA section 111(d) for existing sources, the EPA must make endangerment and cause-or-contribute-significantly findings for emissions from the source category, and the EPA must promulgate regulations for new sources in the source category. In the CAA section 111(b) rule for CO_2 emissions for new affected EGUs that the EPA is promulgating concurrently with this rule, the EPA discusses the endangerment and cause-or-contribute-significantly findings and explains why the EPA has already made them for the affected EGU source categories so that the EPA is not required to make them for CO_2 emissions from affected EGUs, and, in the alternative, why, if the EPA were required to make those findings, it was making them in that rulemaking.

reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. Concurrently with this rule, the EPA is finalizing a CAA section 111(b) rulemaking establishing standards of performance for CO_2 emissions from new fossil fuel-fired EGUs, from modified fossil fuel-fired EGUs, and from reconstructed fossil fuel-fired EGUs, and any of those sets of section 111(b) standards of performance provides the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d)(1) is determining the "best system of emission reduction which . . . the Administrator determines has been adequately demonstrated" (BSER) under CAA section 111(a)(1). It is clear by the terms of section 111(a)(1) and the implementing regulations for section 111(d) that the EPA is authorized to determine the BSER;[285] accordingly, in this rulemaking, the EPA is determining the BSER.

The EPA is finalizing the BSER for fossil fuel-fired EGUs based on building blocks 1, 2, and 3. Building block 1 includes operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate. It qualifies as part of the BSER because it improves the carbon intensity of the affected EGUs in generating electricity through

[285] The EPA is not re-opening that interpretation in this rulemaking.

actions the affected sources may undertake that are adequately demonstrated and whose cost is "reasonable." Building blocks 2 and 3 include increases in low- or zero-emitting generation which substitute for generation from the affected EGUs and thereby reduce CO_2 emissions from those sources. All of these measures are components of a "system of emission reduction" for the affected EGUs because they entail actions that the affected EGUs may themselves undertake that have the effect of reducing their emissions. Further, these measures meet the criteria in CAA section 111(a)(1) and the case law for the "best" system of emission reduction that is "adequately demonstrated" because they achieve the appropriate level of reductions, their cost is "reasonable," they do not have adverse non-air quality health and environmental impacts or impose adverse energy requirements, and they are each well-established among affected EGUs. It should be emphasized that these measures are consistent with current trends in the electricity sector.

Building blocks 2 and 3 may be implemented through a set of measures, including reduced generation from the fossil fuel-fired EGUs. These measures do not, however, reduce the amount of electricity that can be sold or that is available to end users. In addition, states should be expected to allow their affected EGUs to trade rate-based emission credits or mass-based emission allowances (trading) because trading is well-established for this industry and has the effect of focusing costs on the affected EGUs for which reducing emissions is most cost-effective. Because trading facilitates implementation of the building blocks and may help to optimize cost-effectiveness, trading is a method of implementing the BSER as well.

As a result, an affected EGU has a set of choices for achieving its emission standards. For example, an affected coal-fired steam generating unit can achieve a rate-based standard through a set of actions that implement the building block 1 measures and that implement the building block 2 and 3 measures through a set of actions that range from purchasing full or partial interest in existing NGCC or new RE assets to purchasing ERCs that represent the environmental attributes of increased NGCC generation or new renewable generation. In addition, the affected EGU may reduce its generation and thereby reduce the extent that it needs to implement the building blocks. The affected EGU may also purchase rate-based emission credits from other affected EGUs. If the state chooses to impose a mass-based emission standard, the coal-fired steam generating unit may implement building block 1 measures, purchase mass-based emission allowances from other affected EGUs, or reduce its generation. In light of the available sources of lower- and zero-emitting replacement generation, this approach would achieve an appropriate level of emission reductions and maintain the reliability of the electricity system.

With the promulgation of the emission guidelines, each state must develop and submit a plan to achieve the CO_2 emission performance rates established by the EPA or the equivalent statewide rate-based or mass-based goal provided by the EPA in this rule. The EPA interprets CAA section 111(d) to allow states to establish standards of performance and provide for their implementation and enforcement through either the "emission standards" or the "state measures" plan type. In the case of the "emission standards" plan type, the emission standards establish standards of performance, and the other components of the plan provide for their implementation and enforcement. In the case of the "state measures" plan type, —the state submits a plan that relies upon measures that are only enforceable as a matter of state law that will, in conjunction with any emission standards on affected EGUs, result in the achievement of the applicable performance rates or state goals by the affected EGUs. Under the state measures plan type, states must also submit a federally enforceable backstop and a mechanism that would trigger implementation of the backstop; therefore, in a state measures plan, the standards of performance take the form of the backstop, the trigger mechanism provides for the implementation of such backstop, and the other required components of the plan provide for implementation and enforcement of the standards of performance.

These two types of state plans and their respective approaches, which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. It should be noted that both state plan types allow the state flexibility in assigning the emission performance obligations to its affected EGUs in the form of standards of performance as long as the required emission performance level is met. Both plan types harness the efficiencies of emission reduction opportunities in the interconnected electricity system and are fully consistent with the principles of cooperative federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, both plan types achieve the emission performance requirements through the vehicle of a state plan, and provide each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

Both state plan types, and the standards of performance for the affected EGUs that the states will establish through the state plan process, are consistent with the applicable CAA section 111 provisions. A state has discretion in determining the appropriate measures to rely upon for its plan. The state may adopt measures that assure the achievement of the requisite CO_2 emission performance rate or state goal by the affected EGUs, and is not limited to the measures that the EPA identifies as part of the BSER.

In this rulemaking, the EPA establishes reasonable deadlines for state plan submission. Under CAA section 111(d)(1), state plans must "provide for implementation and enforcement" of the standards of performance, and under CAA section 111(d)(2), the state plans must be "satisfactory" for the EPA to approve them. In this rulemaking, the EPA is finalizing the criteria that the state plans must meet under these requirements.

The EPA discusses its legal interpretation in more detail in other parts of this preamble and provides additional information about certain issues in the Legal Memorandum included in the docket for this rulemaking.

IV. Authority for This Rulemaking, Definition of Affected Sources, and Treatment of Source Categories

A. EPA's Authority Under CAA Section 111(d)

EPA's authority for this rule is CAA section 111(d). CAA section 111(d) provides that the EPA will promulgate regulations under which each state will establish standards of performance for existing sources for any air pollutant that meets two criteria. First, CAA section 111(d) applies to air pollutants that are not regulated as a criteria pollutant under section 108 or as a hazardous air pollutant (HAP) under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i).[286] Second, section 111(d) applies only to air pollutants for which the existing source would be regulated under section 111 ifit were a new source. 42 U.S.C. 7411(d)(1)(A)(ii). Here, carbon dioxide (CO_2) meets both criteria: (1) It is not a criteria pollutant regulated under section 108 nor a HAP regulated under CAA section 112, and (2) CO_2 emissions from new power plants (including newly constructed, modified and reconstructed power plants) are regulated under the CAA section 111(b) rule that is being finalized along with this rule.

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[286] Section 111(d) might be read to apply to HAP under certain circumstances. However, because carbon dioxide is not a HAP, this issue does not need to be resolved in the context of this rule.

B. CAA Section 112 Exclusion to CAA Section 111(d) Authority

CAA section 111(d) contains an exclusion that limits the regulation under CAA section 111(d) of air pollutants that are regulated under CAA section 112. 42 U.S.C. 7411(d)(1)(A)(i). This "Section 112 Exclusion" in CAA section 111(d) was the subject of a significant number of comments based on two differing amendments to this exclusion enacted in the 1990 CAA Amendments. As discussed in more detail below, the House and the Senate each initially passed different amendments to the Section 112 Exclusion and both amendments were ultimately passed by both houses and signed into law. In 2005, in connection with the Clean Air Mercury Rule (CAMR), the EPA discussed the agency's interpretation of the Section 112 Exclusion in light of these two differing amendments and concluded that the two amendments were in conflict and that the provision should be read as follows to give both amendments meaning: where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. *See* 70 FR 15994, 16029–32 (March 29, 2005).

In June 2014, the EPA presented this previous interpretation as part of the proposal and requested comment on it. The EPA received numerous comments on its previous interpretation, including comments on the proper interpretation and effect of each of the two differing amendments, and whether the Section 112 Exclusion should be read to mean that the EPA's regulation of HAP from power plants under

CAA section 112 bars the EPA from establishing CAA section 111(d) regulations covering CO_2 emissions from power plants. In particular, many comments focused on two specific issues. First, some commenters—including some industry and state commenters that had previously endorsed the EPA's interpretation of the Section 112 Exclusion in other contexts [287] —argued that the EPA's 2005 interpretation was in error because it allowed the regulation of certain pollutants from source categories under CAA section 111(d) when those source categories were also regulated for different pollutants under CAA section 112. Second, some commenters argued that the EPA's previous interpretation of the House amendment (as originally represented in 2005 at 70 FR at 16029–30) was in error because it improperly read that amendment as focusing on whether a source category was regulated under CAA section 112 rather than on whether the air pollutant was regulated under CAA section 112, and that improper reading lead to an interpretation that was inconsistent with the structure and purpose of the CAA.

[287] For example, in the CAMR litigation (*State of New Jersey* v. *EPA*, No. 05-1097 (D.C. Cir.), the joint brief filed by a group of intervenors and an amicus (including six states and the West Virginia Department of Environmental Protection, and Utility Air Regulatory Group and nine other industry entities) stated that the EPA had interpreted section 111(d) in light of the two different amendments and that the EPA's interpretation was "a reasoned way to reconcile the conflicting language and the Court should defer to the EPA's interpretation." Joint Brief of State Respondent-Intervenors, Industry Respondent-Intervenors, and State Amicus, filed May 18, 2007, at 25.

In light of the comments, the EPA has reconsidered its previous interpretation of the Section 112 Exclusion and, in particular, considered whether the exclusion precludes the regulation under CAA section 111(d) of CO_2 from power plants given that power plants are regulated for certain HAP under CAA section 112. On this issue, the EPA has concluded that the two differing amendments are not properly read as conflicting. Instead, the House amendment and the Senate Amendment should each be read to mean the same in the context presented by this rule: that the Section 112 Exclusion does not bar the regulation under CAA section 111(d) of non-HAP from a source category, regardless of whether that source category is subject to standards for HAP under CAA section 112. In reaching this conclusion, the EPA has revised its previous interpretation of the House amendment, as discussed below.

1. Structure of the CAA and Pre-1990 Section 112 Exclusion

The Clean Air Act sets out a comprehensive scheme for air pollution control, addressing three general categories of pollutants emitted from stationary sources: (1) Criteria pollutants (which are addressed in sections 108–110); (2) hazardous pollutants (which are addressed under section 112); and (3) "pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under sections 108–110 or 112." 40 FR 53340 (Nov. 17, 1975).

Six "criteria" pollutants are regulated under sections 108–110. These are pollutants that the Administrator has concluded "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;" "the presence of which in the ambient air results from numerous and diverse mobile or stationary sources;" and for which the Administrator has issued, or plans to issue, "air quality criteria. 42 U.S.C. 7408(a)(1). Once the EPA issues air quality criteria for such pollutants, the Administrator must propose primary National Ambient Air Quality Standards (NAAQS) for them, set at levels "requisite to protect the public health" with an "adequate margin of safety." 42 U.S.C. 7409(a)–(b). States must then adopt plans for implementing NAAQS. 42 U.S.C. 7410.

HAP are regulated under CAA section 112 and include the pollutants listed by Congress in section 112(b)(1) and other pollutants that the EPA lists under sections 112(b)(2) and (b)(3). CAA section 112 further provides that the EPA will publish and revise a list of "major" and "area" source categories of HAP, and then establish emissions standards for HAP emitted by sources within each listed category. 42 U.S.C. 7412(c)(1) & (2).

CAA section 111, 42 U.S.C. 7411, is the third part of the CAA's structure for regulating stationary sources. Section 111 has two main components. First, section 111(b) requires the EPA to promulgate federal "standards of performance" addressing new stationary sources that cause or contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. 7411(b)(1)(A). Once the EPA has set new source standards addressing emissions of a particular pollutant under CAA section 111(b), CAA section 111(d) provides that the EPA will promulgate regulations requiring states to establish standards of performance for existing stationary sources of the same pollutant. 42 U.S.C. 7411(d)(1).

Together, the criteria pollutant/NAAQS provisions in sections 108–110, the hazardous air pollutant provisions in section 112, and performance standard provisions in section 111 constitute a comprehensive scheme to regulate air pollutants with "no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare." S. Rep. No. 91-1196, at 20 (1970).[288] The specific role of CAA section 111(d) in this structure can be seen in CAA subsection 111(d)(1)(A)(i), which provides that regulation under CAA section 111(d) is intended to cover pollutants that are not regulated under either the criteria pollutant/NAAQS provisions or section 112. Prior to 1990, this limitation was laid out in plain language, which stated that CAA section 111(d) regulation applied to "any air pollutant . . . for which air quality criteria have not been issued or which is not included on a list published under section [108(a)] or [112(b)(1)(A)]." This plain language demonstrated that section 111(d) is designed to regulate pollutants from existing sources that fall in the gap not covered by the criteria pollutant provisions or the hazardous air pollutant provisions.

This gap-filling purpose can be seen in the early legislative history of the CAA. As originally enacted in the 1970 CAA, the precursor to CAA section 111

[288] In subsequent CAA amendments, Congress has maintained this three-part scheme, but supplemented it with the Preservation of Significant Deterioration (PSD) program, the Acid Rain Program and the Regional Haze program.

(which was originally section 114) was described as covering pollutants that would not be controlled by the criteria pollutant provisions or the hazardous air pollutant provisions. See S. Committee Rep. to accompany S. 4358 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 ("It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [which later became section 112]) could be established under section 114 [later, section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."); Statement by S. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 ("[T]he bill [in section 114] provides the Secretary with the authority to set emission standards for selected pollutants which cannot be controlled through the ambient air quality standards and which are not hazardous substances.").

2. The 1990 Amendments to the Section 112 Exclusion

The Act was amended extensively in 1990. Among other things, Congress sought to accelerate the EPA's regulation of hazardous pollutants under section 112. To that end, Congress established a lengthy list of HAP; set criteria for listing "source categories" of such pollutants; and required the EPA to establish standards for each listed source category's hazardous pollutant emissions. 42 U.S.C. 7412(b), (c) and (d). In the course of overhauling the regulation of HAP under section 112, Congress needed to edit section 111(d)'s reference to section 112(b)(1)(A), which was to be eliminated as part of the revisions to section 112.

To address the obsolete cross-reference to section 7412(b)(1)(A), Congress passed two differing amendments—one from the Senate and one from the House—that were never reconciled in conference. The Senate amendment replaced the cross reference to old section 112(b)(1)(A) with a cross-reference to new section 112. Pub. L. 101-549, § 302(a), 104 Stat. 2399, 2574 (1990). The House amendment replaced the cross-reference with the phrase "emitted from a source category which is regulated under section." Pub. L. 101-549, § 108(g), 104 Stat. 2399, 24 67 (1990).[289]

[289] Originally, when the House bill to amend the CAA was introduced in January 1989, it focused on amendments to control HAP. Of particular note, the amendments to section 112 included a provision that excluded regulation under section 112 of "[a]ny air pollutant which is included on the list under section 108(a), or which is regulated for a source category under section 111(d)." H.R. 4, § 2 (Jan. 3, 1989), 1990 CAA Legist. Hist. at 4046. In other words, the Section 112 Exclusion in section 111(d) that was ultimately contained in the House amendment was originally crafted as what might be called a "Section 111(d) Exclusion" in section 112. This is significant because the "source category" phrasing in the original January 1989 text with respect to section 111(d) makes sense, whereas the "source category" phrasing in the 1990 House amendment does not. When referring to the scope of what is regulated under section 111(d), it makes sense to frame that scope with respect to source categories, because section 111 regulation begins with the identification of source categories under section 111(b)(1)(A). By contrast, regulation under section 112 begins with the identification of HAP under section 112(b); the listing of source categories under section 112(c) is secondary to the listing of HAP. From this history, and in light of this difference between the scope of what is regulated in sections 111 and 112, it is reasonable to conclude that the "source category" phrasing is a legacy from the original 1989 bill—that is, when converting the 1989 text into the Section 112 Exclusion that we see in the 1990 House amendment, the legislative drafters continued to use phrasing based on "source category"

Both amendments were enacted into law, and thus both are part of the current CAA. To determine how this provision is properly applied in light of the two differing amendments, we first look at the Senate amendment, then at the House amendment, then discuss how the two amendments are properly read together.

3. The Senate Amendment is Clear and Unambiguous

Unlike the ambiguous amendment to CAA section 111(d) in the House amendment (discussed below), the Senate amendment is straightforward and unambiguous. It maintained the pre-1990 meaning of the Section 112 Exclusion by simply substituting "section 112(b)" for the prior cross-reference to "section 112(b)(1)(A)." Pub. L. 101-549, § 302(a), 104 Stat. 2399, 2574 (1990). So amended, CAA section 111(d) mandates that the EPA require states to submit plans establishing standards for "any air pollutant . . . which is not included on a list published under section [108(a)] or section [112(b)]." Thus, the Section 112 Exclusion resulting from the Senate amendment would preclude CAA section 111(d) regulation of HAP emission but would not preclude CAA section 111(d) regulation of CO_2 emissions from power plants notwithstanding that power plants are also regulated for HAP under CAA section 112.

Some commenters have argued that the Senate amendment should be given no effect, because only the House amendment is shown in the U.S. Code, and

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notwithstanding that this phrasing created a mismatch with the way that the scope of section 112 regulation is determined.

because the Senate amendment appeared under the heading "conforming amendments," and for various other reasons. The EPA disagrees. The Senate amendment, like the House amendment, was enacted into law as part of the 1990 CAA amendments, and must be given effect.

First, that the U.S. Code only reflects the House amendment does not change the fact that both amendments were signed into law as part of the 1990 Amendments, as shown in the Statutes at Large. Pub. L. 101-549, §§ 108(g) and 302(a), 104 Stat. 2399, 2467, 2574 (1990). Where there is a conflict between the U.S. Code and the Statutes at Large, the latter controls. *See* 1 U.S.C. 112 & 204(a); *Stephan* v. *United States*, 319 U.S. 423, 426 (1943) ("the Code cannot prevail over the Statutes at Large when the two are inconsistent"); *Five Flags Pipe Line Co.* v. *Dep't of Transp.*, 854 F.2d 1438, 1440 (D.C. Cir. 1988) ("[W]here the language of the Statutes at Large conflicts with the language in the United States Code that has not been enacted into positive law, the language of the Statutes at Large controls.").

Second, the "conforming" label is irrelevant. A "conforming" amendment may be either substantive or non-substantive. *Burgess* v. *United States*, 553 U.S. 124, 135 (2008). And while the House Amendment contains more words, it also qualifies as a "conforming amendment" under the definition in the Senate Legislative Drafting Manual, Section 126(b)(2) (defining "conforming amendments" as those "necessitated by the substantive amendments of provisions of the bill"). Here, both the House and Senate amendments were "necessitated by" Congress' revisions to section 112 in the 1990 CAA Amendment, which included the deletion of old section 112(b)(1)(A). Thus, the House's amendment is no less "conforming" than the Senate's, and the heading under which it was enacted ("Miscellaneous Guidance") does not suggest any more importance than "Conforming Amendments." In any event, courts gives full effect to conforming amendments, see *Washington Hosp. Ctr.* v. *Bowen*, 795 F.2d 139, 149 (D.C. Cir. 1986), and so neither the Senate Amendment nor the House amendment can be ignored.

Third, the legislative history of the Senate amendment supports the conclusion that the substitution of the updated cross-reference was not a mindless, ministerial decision, but reflected a decision to choose an update of the cross reference instead of the text that was inserted into the Section 112 Exclusion by the House amendment. In mid-1989, the House and Senate introduced identical bills (H.R. 3030 and S. 1490, respectively) to provide for "miscellaneous" changes to the CAA. In both the Senate and House bills as they were introduced in mid-1989, the Section 112 Exclusion was to be amended by taking out "or 112(b)(1)(A)" and inserting "or emitted from a source category which is regulated under section 112." H.R. 3030, as introduced, 101st Cong. § 108 (Jul. 27, 1989); S. 1490, as introduced, 101st Cong. § 108 (Aug. 3, 1989). *See* 1990 CAA Legis. Hist. at 3857 (noting that H.R. 3030 and S.1490, as introduced, were the same). Although S. 1490 was identical to H.R. 3030 when they were introduced, the Senate reported a vastly different bill (S.1630) at the end of 1989. *See* S. 1630, as reported (Dec. 20, 1989), 1990 CAA Legis. Hist. at 7906. As reported and eventually passed, S. 1630 did not contain the text in the House amendment ("or emitted from a source category which is regulated under section 112") and instead contained the substitution of cross references (changing "section 112(b)(1)(A)" to "section 112(b)"). *See* S. 1630, as reported, 101st Cong. § 305, 1990 CAA Legis. Hist. at 8153; S. 1630, as passed, § 305 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 4534. Though the EPA is not aware of any statements in the legislative history that expressly explain the Senate's intent in making these changes to the Senate bill, the sequence itself supports the conclusion that the Senate's substitution reflects a decision to retain the pre-1990 approach of using a cross-reference to 112(b) to define the scope of the Section 112 Exclusion. Whether the difference in approach between the final Senate amendment in S.1630 and the House amendment in H.R. 3030 creates a substantive difference or are simply two different means of achieving the same end depends on what interpretation one gives to the text in the House amendment, which we turn to next.

4. The House Amendment

a. *The House amendment is ambiguous*. Before looking at the specific text of the House amendment, it is helpful to review some principles of statutory interpretation. First, statutory interpretation begins with the text, but does not end there. As the D.C. Circuit Court has explained, "[t]he literal language of a provision taken out of context cannot provide conclusive proof of congressional intent." *Bell Atlantic Telephone Cos.* v. *F.C.C.*, 131 F.3d 1044, 1047 (D.C. Cir. 1977). *See King* v. *Burwell*, 2015 U.S. LEXIS 4248, *19("[O]ftentimes the 'meaning—or ambiguity—of certain words or phrases may only become evident when placed in context.' *Brown & Williamson*, 529

U.S., at 132, 120 S. Ct. 1291, 146 L. Ed. 2d 121. So when deciding whether the language is plain, we must read the words 'in their context and with a view to their place in the overall statutory scheme.' *Id.*, at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121 (internal quotation marks omitted). Our duty, after all, is 'to construe statutes, not isolated provisions.' *Graham County Soil and Water Conservation Dist.* v. *United States ex rel. Wilson*, 559 U.S. 280, 290, 130 S. Ct. 1396, 176 L. Ed. 2d 225 (2010) (internal quotation marks omitted)."). In addition, statutes should not be given a "hyperliteral" reading that is contrary to established canons of statutory construction and common sense. *See RadLAX Gateway Hotel* v. *Amalgamated Bank*, 132 S.Ct. 2065, 2070–71 (2012).

Further, a proper reading of statutory text "must employ all the tools of statutory interpretation, including text, structure, purpose, and legislative history." *Loving* v. *I.R.S.*, 742 F.3d 1013, 1016 (D.C. Cir. 2014) (internal quotation omitted). See, also, *Robinson* v. *Shell Oil Co.*, 519 U.S. 337, 341 (1997) (statutory interpretation involves consideration of "the language itself, the specific context in which that language is used, and the broader context of the statute as a whole."). Moreover, one principle of statutory construction that has particular application here is that provisions in a statute should be read to be consistent, rather than conflicting, if possible. This principle was discussed in the recent case of *Scialabba* v. *Cuellar De Osorio*, 134 S. Ct. 2191, 2214 (concurring opinion by Chief Justice Roberts and Justice Scalia), 2219–2220 (dissent by Justices Sotomayor, Breyer and Thomas) (2014). As Justice Sotomayor wrote (at 134 S. Ct. at 2220):

> "We do not lightly presume that Congress has legislated in self-contradicting terms. *See* A. Scalia & B. Garner, Reading Law: The Interpretation of Legal Texts 180 (2012) ("The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously"). . . . Thus, time and again we have stressed our duty to "fit, if possible, all parts [of a statute] into [a] harmonious whole." *FTC* v. *Mandel Brothers, Inc.*, 359 U.S. 385, 389, 79 S. Ct. 818, 3 L. Ed. 2d 893 (1959); see also *Morton* v. *Mancari*, 417 U.S. 535, 551, 94 S. Ct. 2474, 41 L. Ed. 2d 290 (1974) (when two provisions "are capable of co-existence, it is the duty of the courts . . . to regard each as effective"). In reviewing an agency's construction of a statute, courts "must," we have emphasized, "interpret the statute 'as a . . . coherent regulatory scheme' "rather than an internally inconsistent muddle, at war with itself and defective from the day it was written. *Brown & Williamson*, 529 U.S., at 133, 120 S. Ct. 1291, 146 L. Ed. 2d 121.

As amended by the House, CAA section 111(d)(1)(A)(i) limits CAA section 111(d) to any air pollutant "for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title. . ." This statutory text is ambiguous and subject to numerous possible readings.

First, the text of the House-amended version of CAA section 111(d) could be read literally as authorizing the regulation of any pollutant that is not a criteria pollutant. This reading arises if one focuses on the use of "or" to join the three clauses:

> The Administrator shall prescribe regulations . . . under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant [1] for which air quality criteria have not been issued or [2] which is not included on a list published under section 7408(a) of this title or [3] emitted from a source category which is regulated under section 7412 of this title. . . .

42 U.S.C. 7411(d)(1) (emphasis and internal numbering added). Because the text contains the conjunction "or" rather than "and" between the three clauses, a literal reading could read the three clauses as alternatives, rather than requirements to be imposed simultaneously. In other words, a literal reading of the language of section 111(d) provides that the Administrator may require states to establish standards for an air pollutant so long as either air quality criteria have not been established for that pollutant, or one of the remaining criteria is met. If this reading were applied to determine whether the EPA may promulgate CAA section 111(d) regulations for CO_2 from power plants, the result would be that CO_2 from power plants could be regulated under CAA section 111(b) because air quality criteria have not been issued for CO_2 and therefore whether CO_2 or power plants are regulated under CAA section 112 would be irrelevant. This reading, however, is not a reasonable reading of the statute because, among other reasons, it gives little or no meaning to the

limitation covering HAP that are regulated under CAA section 112 and thus is contrary to both the CAA's comprehensive scheme created by the three sets of provisions (under which CAA section Illis not intended to duplicate the regulation of pollutants regulated under section 112) and the principle of statutory construction that text should not be construed such that a provision does not have effect.

A second reading of CAA section 111(d) as revised by the House amendment focuses on the lack of a negative before the third clause. That is, unlike the first and second clauses that each contain negative phrases (either "has not been issued" or "which is not included"), the third clause does not. One could presume that the negative from the second clause was intended to carry over, implicitly inserting another "which is not" before "emitted from a source category which is regulated under section [112]." But that is a presumption, and not the plain language of the statute. The text as amended by the House says that the EPA "shall" prescribe regulations for "any air pollutant . . . emitted from a source category which is regulated under section [112]." 42 U.S.C. 7411(d)(1). Thus, CAA section 111(d)(l)(A)(i) could be read as providing for the regulation of emissions of pollutants if they are emitted from a source category that is regulated under CAA section 112. Like the first reading discussed above, this reading would authorize the regulation of CO_2 emissions from existing power plants under CAA section 111(d). But, this second reading is not reasonable because it would provide for the regulation of a source's HAP emissions under CAA section 111(d) when those same emissions were also subject to standards under CAA section 112. Thus, this reading would be contrary to Congress's intent that CAA section 111(d) regulation fill the gap between the other programs by covering pollutants that the other programs do not, but not duplicate the regulation of pollutants that the other programs cover.

If one does presume that the "which is not" phrase is intended to carry over to the third clause, then CAA section 111(d) regulation under the House amendment would be limited to "any air pollutant . . . which is not . . . emitted from a source category which is regulated under section [112]." Even with this presumption, however, the House amendment contains further ambiguities with respect to the phrases "a source category" and "regulated under section 112," and how those phrases are used within the structure of the provision limiting what air pollutants may be regulated under CAA section 111(d).

The phrase "regulated under section 112" is ambiguous. As the Supreme Court has explained in the context of other statutes using a variation of the word "regulate," an agency must consider what is being regulated. *See Rush Prudential HMO, Inc.* v. *Moran*, 536 U.S. 355, 366 (2002) (It is necessary to "pars[e] . . . the 'what' "of the term "regulates."); *UNUM Life Ins. Co. of Am.* v. *Ward*, 526 U.S. 358, 363 (1999) (the term " 'regulates insurance' . . . requires interpretation, for [its] meaning is not plain."). Here, one possible reading is that the phase modifies the words "a source category" without regard to what pollutants are regulated under section 112, which then presents the issue of what meaning to give to the phrase "a source category."

Under this reading, and assuming the phrase "a source category" is read to mean the particular source category, the House amendment would preclude the regulation under CAA section 111(d) of a specific source category for any pollutant if that source category has been regulated for any HAP under CAA section 112.[290] The effect of this reading would be to preclude the regulation of CO_2 from power plants under CAA section 111(d) because power plants have been regulated for HAP under CAA section 112. This is the interpretation that the EPA applied to the House amendment in connection with the CAMR rule in 2005, when looking at the question of whether HAP can be regulated under CAA section 111(d) for a source category that is not regulated for HAP under section 112, and some commenters have advocated for this interpretation here. But, after considering all of the comments and reconsidering this interpretation, the EPA has concluded that this interpretation of the House amendment is not a reasonable reading because it would disrupt the comprehensive scheme for regulating existing sources created by the three sets of provisions covering criteria pollutants, HAP and the other pollutants that fall outside of those two programs and frustrate the role that section 111 is

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[290] "A source category" could also be interpreted to mean "any source category." Under this interpretation, CAA 111(d) regulation would be limited to air pollutants that are not emitted by any source category for which the EPA has issued standards for HAP under CAA section 112. This interpretation is not reasonable because it would effectively read CAA 111(d) out of the statute. Given the extensive list of source categories regulated under CAA 112 and the breadth of pollutants emitted by those categories collectively, literally all air pollutants would be barred from CAA 111(d) regulation under this interpretation.

intended to play.[291] Specifically, under this interpretation, the EPA could not regulate a source category's emissions of HAP under CAA section 112, and then promulgate regulations for other pollutants from that source category under CAA section 111(d).[292] There is no reason to conclude that the House amendment was intended to abandon the existing structure and relationship between the three programs in this way. Indeed, Congress expressly provided that regulation under CAA section 112 was not to "diminish or replace the requirements of" the EPA's regulation of non-hazardous pollutants under section 7411. *See* 42 U.S.C. 7412(d)(7). Further, consistent with CAA section 112's direction that EPA list "all categories and subcategories of major sources and area [aka, non-major] sources" of HAP and then establish CAA section 112 standards for those categories and subcategories, 42 U.S.C. 7412(c)(1) and (c)(2), the EPA has listed and regulated over 140

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[291] In assessing any interpretation of section 111(d), EPA must consider how the three main programs set forth in the CAA work together. *See UARG*, 134 S. Ct. at 2442 (a "reasonable statutory interpretation must account for . . . the broader context of the statute as a whole") (quotation omitted).

[292] Supporters of this interpretation have noted that the EPA could regulate power plants under both CAA section 111(d) and CAA section 112 if it regulated under section 111(d) first, before the Section 112 Exclusion is triggered. But that argument actually further demonstrates another reason why this interpretation is unreasonable. There is no basis for concluding that Congress intended to mandate that section 111(d) regulation occur first, nor is there any logical reason why the need to regulate under section 111(d) should be dependent on the timing of such regulation in relation to CAA 112 regulation of that source category.

categories of sources under CAA section 112. Thus, this reading would eviscerate the EPA's authority under section 111(d) and prevent it from serving as the gap-filling provision within the comprehensive scheme of the CAA as Congress intended.[293] In short, it is not reasonable to interpret the Section 112 Exclusion in section 111(d) to mean that the existence of CAA section 112 standards covering hazardous pollutants from a source category would entirely eliminate

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[293] Some commenters have stated that EPA could choose to regulate both HAP and non-HAP under section 111(d), and thus could regulate HAP without creating a gap. But this presumes that Congress intended EPA to have the choice of declining to regulate a section 112-listed source category for HAP under section 112, which is inconsistent with the mandatory language in section 112. See, *e.g.*, section 112(d)(1)("The Administrator shall promulgate regulations establishing emissions standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) of this section in accordance with the schedules provided in subsections (c) and (e) of this section."). Moreover, given the prescriptive language that Congress added into section 112 concerning how to set standards for HAP, see section 112(d)(2) and (d)(3), it is unreasonable to conclude that Congress intended that the EPA could simply choose to ignore the provisions in section 112 and instead regulate HAP for a section 112 listed source category under section 111(d).

Further, some supporters of this interpretation have suggested that EPA could regulate CO_2 under section 112. But this suggestion fails to consider that sources emitting HAP are major sources if they emit 10 tons of any HAP. *See* CAA section 112(a)(1). Thus, if CO_2 were regulated as a HAP, and because emissions of CO_2 tend to be many times greater than emissions of other pollutants, a huge number of smaller sources would become regulated for the first time under the CAA.

regulation of non-hazardous emissions from that source category under section 111(d).[294]

b. *The EPA's Interpretation of the House Amendment*. Having concluded that the interpretations discussed above are not reasonable, the EPA now turns to what it has concluded is the best, and sole reasonable, interpretation of the House amendment as it applies to the issue here.

The EPA's interpretation of the House amendment as applied to the issue presented in this rule is that the Section 112 Exclusion excludes the regulation of HAP under CAA section 112 if the source category at issue is regulated under CAA section 112, but does not exclude the regulation of other pollutants, regardless of whether that source category is subject to CAA section 112 standards. This interpretation reads the phrase "regulated under section 112" as modifying the words "source category" (as does the interpretation discussed above) but also recognizes that the phrase "regulated under section 112" refers only to the regulation of HAP emissions. In other words, the

[294] Even if one were to determine that this interpretation were the proper reading of the House amendment that would not be the end of the analysis. Instead, that reading would create a conflict between the Senate amendment and the House amendment that would need to be resolved. In that event, the proper resolution of a conflict between the two amendments would be the analysis and conclusion discussed in the Proposed Rule's legal memorandum (discussing EPA's analysis in the CAMR rule at 70 FR 15994, 16029–32): The two amendments must be read together so as to give some effect to each amendment and they are properly read together to provide that, where a source category is regulated under section 112, the EPA may not establish regulations covering the HAP emissions from that source category under section 111(d).

EPA's interpretation recognizes that source categories "regulated under section 112" are not regulated by CAA section 112 with respect to all pollutants, but only with respect to HAP. Thus, it is reasonable to interpret the House amendment of the Section 112 Exclusion as only excluding the regulation of HAP emissions under CAA section 111(d) and only when that source category is regulated under CAA section 112. We note that this interpretation of the House amendment alone is the same as the 2005 CAMR interpretation of the two amendments combined: Where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category. *See* 70 FR 15994, 16029–30 (March 29, 2005).

There are a number of reasons why the EPA's interpretation is reasonable and avoids the issues discussed above.

First, the EPA's interpretation reads the House amendment to the Section 112 Exclusion as determining the scope of what air pollutants are to be regulated under CAA section 111(d), as opposed to creating a wholesale exclusion for source categories. The other text in subsections 111(d)(l)(A)(i) and (ii) modify the phrase "any air pollutant." Thus, reading the Section 112 Exclusion to also address the question of what air pollutants may be regulated under CAA section 111(d) is consistent with the overall structure and focus of CAA section 111(d)(1)(A).

Second, the EPA's interpretation furthers—rather than undermines—the purpose of CAA section 111(d) within the long-standing structure of the CAA. That is, this interpretation supports the comprehensive structure for regulating various pollutants from existing sources under the criteria pollutant/NAAQS program under sections 108–110, the HAP program under section 112, and other pollutants under section 111(d), and avoids creating a gap in that structure. See *King* v. *Burwell*, 2015 U.S. LEXIS 4248, *28 (2015) ("A provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme . . . because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law.") (quoting *United Sav. Assn, of Tex.* v. *Timbers of Inwood Forest Associates, Ltd.*, 484 U.S. 365, 371, 108 S. Ct. 626, 98 L. Ed. 2d 740 (1988)")

Third, by avoiding the creation of gaps in the statutory structure, the EPA's interpretation is consistent with the legislative history demonstrating that Congress's intent in the 1990 CAA Amendments was to expand the EPA's regulatory authority across the board, compelling the agency to regulate more pollutants, under more programs, more quickly.[295]

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[295] *See* S. Rep. No. 101-228 at 133 ("There is now a broad consensus that the program to regulate hazardous air pollutants . . . should be restructured to provide the EPA with authority to regulate industrial and area sources of air pollution . . . in the near term"), reprinted in 5 *A Legislative History of the Clean Air Act Amendments of 1990* ("Legis. Hist.") 8338, 8473 (Comm. Print 1993); S. Rep. No. 101-228 at 14 ("The bill gives significant authority to the Administrator in order to overcome the deficiencies in [the NAAQS program]") & 123 ("Experience with the mobile source provisions in Title II of the Act has shown that the enforcement authorities . . . need to be strengthened and broadened . . ."), reprinted in 5 *Legis. Hist.* at

Conversely, the EPA is aware of no statement in the legislative history indicating that Congress simultaneously sought to restrict the EPA's authority under CAA section 111(d) or to create gaps in the comprehensive structure of the statute. If Congress had intended this amendment to make such a change, one would expect to see some indication of that in the legislative history.

Fourth, when applied in the context of this rule, the EPA's interpretation of the House amendment is consistent with the Senate amendment. Thus, this interpretation avoids creating a conflict within the statute. *See* discussion above of *Scialabba* v. *Cuellar De Osorio*, 134 S. Ct. 2191 at 2220 (citing and quoting, among other authorities, A. Scalia & B. Garner, Reading Law: The Interpretation of Legal Texts 180 (2012) ("The provisions of a text should be interpreted in a way that renders them compatible, not contradictory. . . . [T]here can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously")).

In sum, when this interpretation of the House amendment is applied in the context of this rule, the result is that the EPA may promulgate CAA section 111(d) regulations covering carbon dioxide emissions from existing power plants notwithstanding that

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8354, 8463; H.R. Rep. No. 101-952 at 336–36, 340, 345 & 347 (discussing enhancements to Act's motor vehicle provisions, the EPA's new authority to promulgate chemical accident prevention regulations, the enactment of the Title V permit program, and enhancements to the EPA's enforcement authority), reprinted in 5 *Legis. Hist*. at 1786, 1790, 1795, & 1997.

power plants are regulated for their HAP emissions under CAA section 112.

5 The Two Amendments Are Easily Reconciled and Can Be Given Full Effect

Given that both the House and Senate amendments should be read individually as having the same meaning in the context presented in this rule, giving each amendment full effect is straight-forward: The Section 112 Exclusion in section 111(d) does not foreclose the regulation of non-HAP from a source category regardless of whether that source category is also regulated under CAA section 112. As applied here, the EPA has the authority to promulgate CAA section 111(d) regulations for CO_2 from power plants notwithstanding that power plants are regulated for HAP under CAA section 112.

C. Authority To Regulate EGUs

In a separate, concurrent action, the EPA is also finalizing a CAA section 111(b) rulemaking that regulates CO_2 emissions from new, modified, and reconstructed EGUs. The promulgation of these standards provides the requisite predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating "any existing source" of certain pollutants "to which a standard of performance would apply if such existing source were a new source." A "new source" is "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 [CAA section 111] which will be applicable to such source." It should be noted that these provisions make clear that a "new source" includes one that undertakes either new construction or a modification. It should also be noted that the EPA's implementing regulations define "construction" to include "reconstruction," which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include standards for sources that undertake new construction, modifications, or reconstructions.

The EPA is finalizing a rulemaking under CAA section 111(b) for CO_2 emissions from affected EGUs concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).[296]

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[296] In the past, the EPA has issued standards of performance under section 111(b)and emission guidelines under section 111(d) simultaneously. *See* "Standards of Performance for new Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills—Final Rule," 61 FR 9905 (March 12, 1996).

D. Definition of Affected Sources

For the emission guidelines, an affected EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.*, utility boiler or integrated gasification combined cycle (IGCC) unit) or stationary combustion turbine that was in operation or had commenced construction as of January 8, 2014,[297] 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 a fossil fuel-fired electric utility steam generating unit (*i.e.*, a utility boiler or IGCC unit), 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 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a stationary combustion turbine, the unit must meet the definition of a combined cycle or combined heat and power 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

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[297] 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).

stationary combustion turbine itself. Combined cycle combustion turbine means any stationary combustion turbine 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. Combined heat and power (CHP) combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine engine exhaust gases to heat water or another medium, generate 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. Affected EGUs that may be excluded from a state's plan are (1) those units that are subject to subpart TTTT as a result of commencing modification or reconstruction; (2) steam generating units 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) 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) stationary combustion turbines that are not capable of combusting natural gas (*i.e.*, not connected to a natural gas pipeline); (5) combined heat and power 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) units that serve a generator along with other steam generating unit(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 steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less; (7) municipal waste combustor unit subject to subpart Eb of Part 60; or (8) commercial or industrial solid waste incineration units that are subject to subpart CCCC of Part 60.

The rationale for applicability of this final rule is multi-fold. We had proposed that affected EGUs were those existing 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 section 111(b). However, we are finalizing that States need not include certain units that would otherwise meet the CAA section 111(b) applicability in this CAA section 111(d) emission guidelines. These include simple cycle turbines, certain non-fossil units, and certain combined heat and power units. The final 111(b) standards include applicability criteria for simple cycle combustion turbines, for reasons relating to implementation and minimizing emissions from all future combustion turbines. However, for the following reasons none of the building blocks would result in emission reductions from simple cycle turbines so we are not requiring that States including them in their CAA section 111(d) plans.

First, even more than combined cycle units, simple cycle units have limited opportunities, compared to steam generating units, to reduce their heat rate. Most combustion turbines likely already follow the manufacturer's recommended regular preventive/ restorative maintenance for both reliable and efficiency reasons. These regularly scheduled maintenance practices are highly effective methods to maintain heat rates, and additional fleet-wide reductions from simple cycle combustion turbines are likely less than 2 percent. In addition, while approximately one-fifth of overall fossil fuel-fired capacity (GW) consists of simple cycle turbines, these units historically have operated at capacity factors of less than 5 percent and only provide about 1 percent of the fossil fuel-fired generation (GWh). Combustion turbine capacity can therefore only contribute CO_2 emissions amounting to approximately 2 percent of total coal-steam CO_2 emissions. Any single-digit percentage reduction in combustion turbine heat rates would therefore provide less than 1 percent reduction in total fossil-fired CO_2 emissions.

Further, we are not aware of an approach to estimate any limited opportunities that existing simple cycle turbines may have to reduce their heat rate. Similar to coal-steam EGUs, we do not have the unit-specific detailed design information on existing individual simple cycle combustion turbines that is necessary for a detailed assessment of the heat rate improvement potential via best practices and upgrades for each unit. While the EPA could conduct a "variability analysis" of simple cycle historical hourly heat rate data (as was done for coal-steam EGUs), the various simple cycle models in use and the historically lower capacity factors of the simple cycle fleet (less run time per start, and more part load operation) would require a simple cycle analysis that includes more complexity and likely more uncertainty than in the coal-steam analysis. Therefore, we do not consider it feasible to estimate potential reductions due to heat rate improvements from simple cycle turbines, and even if it were, we have concluded those reductions would be negligible compared to the reductions from steam generating units. Hence, we do not consider building block 1 as practically applicable to simple cycle units.

Second, the vast majority of simple cycle turbines serve a specific need—providing power during periods of peak electric demand (*i.e.*, peaking units). The existing block of simple cycle turbines are the only units that are able to start fast enough and ramp to full load quickly enough to serve as peaking units. If these units were to be used under building block 2 to displace higher emitting coal-fired units, they would no longer be available to serve as peaking units. Therefore, building block 2 could not be applied to simple cycle combustion turbines without jeopardizing grid reliability.

Third, many commenters on the CAA section 111(b) proposal stated that simple cycle turbines will be used to provide backup power to intermittent renewable sources of power such as wind and solar. Consequently, adding additional generation from intermittent renewable sources has the potential to actually increase emissions from simple cycle turbines. Therefore, applying building block 3 based on the capacity of simple cycle turbines would not result in emission reductions from simple cycle combustion turbines. Finally, the EPA expects existing simple cycle turbines to continue to operate as they historically have operated, as peaking units. Including simple cycle turbines in CAA section 111(d) applicability would impact the numerical value of state goals, but it would not impact the stringency of the plans. Such inclusion would increase burden but result in no environmental benefit.

Additionally, under CAA section 111(b) final applicability criteria, new dedicated non-fossil and industrial CHP units are not affected sources if they include permit restrictions on the amount of fossil fuel they burn and the amount of electricity they sell. Such units historically have had no regulatory mandate to include permit requirements limiting the use of fossil fuel or electric sales. We are exempting them from inclusion in CAA section 111(d) state plans in the interest of consistency with CAA section 111(b) and based on their historical fuel use and electric sales.

We discuss changes in applicability of units in relation to state plans in Section VIII of this preamble.

E. Combined Categories and Codification in the Code of Federal Regulations

In this rulemaking, the EPA is combining the listing of sources from the two existing source categories for the affected EGUs, as listed in 40 CFR subpart Da and 40 CFR subpart KKKK, into a single location, 40 CFR subpart UUUU, for purposes of addressing the CO_2 emissions from existing affected EGUs. The EPA is also codifying all of the requirements for the affected EGUs in a new subpart UUUU of 40 CFR part 60 and including all GHG emission guidelines for the affected sources—fossil fuel-fired electric utility steam generating units, as well as stationary combustion turbines—in that newly created subpart.[298]

We believe that combining the emission guidelines for affected sources into a new subpart UUUU is appropriate because the emission guidelines the EPA is establishing do not vary by type of source. Combining the listing of sources into one location, subpart UUUU, will facilitate implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (*e.g.*, shifting from utility boilers to NGCC units), and emission trading among sources in the source category.

As discussed in the January 8, 2014 proposal for the CAA section 111(b) standards for GHG emissions from EGUs (79 FR 1430), in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60 subparts D, Da, GG, and KKKK.

In the January 8, 2014 proposal, the EPA proposed separate standards of performance for new sources in the two categories and proposed codifying the standards in the same Da and KKKK subparts that currently contain the standards of performance for

[298] The EPA is not codifying any of the requirements of this rulemaking in subparts Da or KKKK.

conventional pollutants from those sources. In addition, the EPA co-proposed combining the two categories into a single category solely for purposes of the CO_2 emissions from new construction of affected EGUs, and codifying the proposed requirements in a new 40 CFR part 60 subpart TTTT. For the final standards of performance for new construction of affected EGUs, the EPA is codifying the final requirements in a new 40 CFR part 60 subpart TTTT.

In this rulemaking, the EPA is combining the two listed source categories into a single source category for purposes of the emission guidelines for the CO_2 emissions from existing affected EGUs. Because the two source categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined source category is not considered a new source category that the EPA must list under CAA section 111(b)(1)(A). As a result, this final rule does not list a new source category under section 111(a)(1)(A), nor does this final rule revise either of the two source categories—fossil fuel—fired electric utility steam generating units and stationary combustion turbines—that the EPA has already listed under that provision. Thus, the EPA is not required to make a finding that the combined source category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

V. The Best System of Emission Reduction and Associated Building Blocks

In the June 2014 proposal, the EPA proposed to determine that the best system of emission reduction adequately demonstrated (BSER) for reducing CO_2

emissions from existing EGUs was a combination of measures—(1) increasing the operational efficiency of existing coal-fired steam EGUs, (2) substituting increased generation at existing NGCC units for generation at existing steam EGUs, (3) substituting generation from low- and zero-carbon generating capacity for generation at existing fossil fuel-fired EGUs, and (4) increasing demand-side EE to reduce the amount of fossil fuel-fired generation—which we categorized as four "building blocks." As an alternative to the proposed building blocks 2, 3, and 4, the EPA also identified reduced generation in the amount of those building blocks as part of the BSER. These measures are not the only approaches EGUs can take to reduce CO_2, but are those that the EPA felt best met the statutory criteria. We solicited comment on all aspects of our BSER determination, including a broad array of other approaches. We have considered thoroughly the extensive comments submitted on a variety of topics related to the BSER and the individual building blocks, along with our own continued analysis, and we are finalizing the BSER based on the first three building blocks, with certain refinements.

Consistent with the approach taken in the proposed rule, in determining the BSER we have taken account of the unique characteristics of CO_2 pollution, particularly its global nature, huge quantities, and the limited means for controlling it; and the unique characteristics of the source category, particularly the exceptional degree of interconnectedness among individual affected EGUs and the longstanding practice of coordinating planning and operations across multiple sources, reflecting the fact that each

EGU's function is interdependent with the function of other EGUs. Each building block is a proven approach for reducing emissions from the affected source category that is appropriate in this pollutant- and industry-specific context. The BSER also encompasses a variety of measures or actions that individual affected EGUs could take to implement the building blocks, including (i) direct investment in efficiency improvements and in lower- and zero-carbon generation, (ii) cross-investment in these activities through mechanisms such as emissions trading approaches, where the state-established standards of performance to which sources are subject incorporate such approaches, and (iii) reduction of higher-carbon generation.

With attention to emission reduction costs, electricity rates, and the importance of ensuring continued reliability of electricity supplies, the individual building blocks and the overall BSER have been defined not at the maximum possible degree of stringency but at a reasonable degree of stringency designed to appropriately balance consideration of the various BSER factors. Additional, non-building block-specific aspects of the BSER quantification methodology discussed below are similarly mindful of these considerations. This approach to determination of the BSER provides compliance headroom that ensures that the emission limitations reflecting the BSER are achievable by the source category, but nevertheless, as required by the CAA, will result in meaningful reductions in CO_2 emissions from this sector. The wide range of actions encompassed in the building blocks, and a further wide range of possible emissions-reducing actions not included in the BSER but nevertheless available to help with compliance, ensure that those emission limitations are achievable by individual affected EGUs as well.

The final BSER incorporates certain changes from the proposed rule, reflecting the EPA's consideration of comments responding to the approaches outlined in the proposal and our own further analysis. The principal changes are the exclusion from the BSER of emission reductions achievable through demand-side EE and through nuclear generation; a revised approach to determination of emission reductions achievable through increased RE generation; a consistent approach to determination of emission reductions achievable through all the building blocks that better reflects the regional nature of the electricity system and entails separate analyses for the Eastern, Western, and Texas Interconnections; and a revised interim goal period of 2022 to 2029 (instead of the proposed interim period of 2020 to 2029). These changes to the BSER and the building blocks are discussed in more detail later in this section of the preamble.

Also, to address concerns identified in the proposal and the October 30, 2014 NODA and in response to associated comments, in the final rule we have represented the emission limitations achievable through the BSER in the form of uniform CO_2 emission performance rates for each of two affected source subcategories: Steam generating units and stationary combustion turbines. However, like the proposed rule, the final rule also provides weighted-average state-specific goals that a state may choose as an alternative method for complying with its obligation to set standards of performance for its affected EGUs—an alternative, that is, to adopting the nationwide subcategory-based CO_2 emission performance rates as the standard of performance for its affected EGUs. The reformulation of the emission limitations as uniform CO_2 emission performance rates is discussed in this section and in section VI of the preamble, and the relation of the performance rates to the state-specific goals and states' section 111(d) plan options is discussed in sections VII and VIII of the preamble.

Section V.A. describes our determination of the final BSER, including a discussion of the associated emissions performance level, and provides the rationale for our determination. In section V.B. we address certain legal issues in greater detail, including key issues raised in comments. Sections V.C. through V.E. contain more detailed discussions of the three individual building blocks included in the final BSER. Further information can be found in the GHG Mitigation Measures TSD for the CPP Final Rule, the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, the Response to Comments document, and, about certain topics, the Legal Memorandum for the Clean Power Plan Final Rule, all of which are available in the docket.

A. The Best System of Emission Reduction

This section sets forth our determination of the BSER for reducing CO_2 emissions from existing EGUs, including a discussion of the associated emissions performance level, and the rationale for that determination. In section V.A.I., we describe the legal framework for determination of the BSER in general.

Section V.A.2. summarizes the determination of the BSER for this rule. In section V.A.3., we discuss changes from the proposal. Section V.A.4. provides more detail on our determination of the BSER, including our determinations regarding the individual elements of the BSER, as applied to the two subcategories of fossil steam units and combustion turbines. In section V.A.5., we explain the specific actions that individual affected EGUs in the two subcategories may take to implement the building blocks and thereby achieve the EPA-identified source subcategory-specific emission performance rates that, in turn, form the basis for the standards of performance that states must set. Because these actions implement the building blocks, they may be understood as part of the BSER. In this discussion, we recognize that states can choose to set sources' standards of performance in different forms and that the form of the standard affects how various types of actions can be used to comply with the standard. In section V.A.6., we discuss the substantial compliance flexibility provided by additional measures, not included in the BSER, that individual affected EGUs can use to achieve their standards of performance. Finally, section V.A.7. addresses the severability of the building blocks.

1. Legal Requirements for BSER in the Emission Guidelines

a. *Introduction*. In the June 2014 proposal for this rule, we described the principal legal requirements for standards of performance under CAA section 111(d)(1) and (a)(1). We based our description in part on our discussion of the legal requirements for standards of performance under CAA section 111(b) and (a)(1), which we included in the January 2014 proposal for standards of performance for CO_2 emissions from new fossil fuel-fired EGUs. In the latter proposal, we noted that the D.C. Circuit has handed down numerous decisions that interpret CAA section 111(a)(1), including its component elements, and we reviewed that case law in detail.[299]

We received comments on our proposed interpretation, and in light of those comments, in this final rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[300]

b. *CAA requirements and court interpretation.*[301] Section 111(d)(1) directs the EPA to promulgate

[299] 79 FR 1430, 1462 (January 8, 2014).

[300] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(b), for new sources, in the section 111(b) rulemaking that the EPA is finalizing simultaneously with this rule and in the Legal Memorandum for this rule. Our interpretations of these requirements in the two rules are generally consistent except to the extent that they reflect distinctions between new and existing sources. For example, as discussed in the section 111(b) rule, the legislative history indicates that Congress intended that the BSER for new industrial facilities, which were expected to have lengthy useful lives, would include the most advanced pollution controls available, but Congress had a broader conception of the BSER for existing facilities.

[301] Our interpretation of the CAA provisions at issue is guided by *Chevron U.S.A. Inc.* v. *NRDC*, 467 U.S. 837, 842–43 (1984). In *Chevron*, the U.S. Supreme Court set out a two-step process for agency interpretation of statutory requirements: the agency must, at step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then, at

regulations establishing a section 110-like procedure under which states submit state plans that establish "standards of performance" for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under section 111(b), and that implement and enforce those standards of performance.

The term "standard of performance" is defined 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Section 111(a)(1).

These provisions authorize the EPA to determine the BSER for the affected sources and, based on the BSER, to establish emission guidelines that identify the minimum amount of emission limitation that a state, in its state plan, must impose on its sources through standards of performance. Consistent with these CAA requirements, the EPA's regulations require that the EPA's guidelines reflect—

> the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the

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step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.

> cost of such reduction) the Administrator has determined has been adequately demonstrated.[302]

The EPA's approach in this rulemaking is to determine the BSER on a source subcategory-wide basis, to determine the emission limitation that results from applying the BSER to the sources in the subcategory, and then to establish emission guidelines for the states that incorporate those emission limitations. The EPA expresses these emission limitations in the form of emission performance rates, and they must be achievable by the source subcategory through the application of the BSER.

Following the EPA's promulgation of emission guidelines, each state must determine the standards of performance for its sources, which the EPA's regulations call "designated facilities." [303] A state has broad discretion in doing so. CAA section 111(d)(1) requires the EPA's regulations to "permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the . . . source. . ."[304] In addition, under CAA section 116, the

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[302] 40 CFR 60.21(e). This definition was promulgated as part of the EPA's CAA 111(d) implementing regulations and was not updated to reflect the textual changes adopted by Congress in 1977. That said, Congress recognized that those changes "merely make) explicit what was implicit in the previous language." H.R. Rep. No. 95-294, at 190 (May 12, 1977).

[303] 40 CFR 60.24(b)(3).

[304] The EPA's regulations, promulgated prior to enactment of the "remaining useful life" provision of section 111(d)(1), provide: "Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities, or classes of

state is authorized to set a standard of performance for any particular source that is more stringent than the emission limit contained in the EPA's emission guidelines.[305] Thus, for any particular source, a state may apply a standard of performance that is either more stringent or less stringent than the performance level in the emission guidelines, as long as, in total, the state's sources achieve at least the same degree of emission limitation as included in the EPA's emission guidelines. The states must include the standards of performance in their state plans and submit the plans to the EPA for review.[306] Under CAA section 111(d)(2)(A), the EPA approves state plans as long as they are "satisfactory."

As noted in the January 2014 proposal and discussed in more detail above under section II.G, Congress first included the definition of "standard of performance" when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the

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facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required" by the corresponding emission guideline. 40 CFR 60.24(f). Some of the factors that a state may consider for this case-by-case analysis include the "cost of control resulting from plant age, location, or basic process design" and the "physical impossibility of installing necessary control equipment," among other factors "that make application of a less stringent standard or final compliance time significantly more reasonable." *Id.*

[305] In addition, CAA section 116 authorizes the state to set standards of performance for all of its sources that, together, are more stringent than the EPA's emission guidelines.

[306] 40 CFR 60.23.

1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAA that Congress primarily addressed the definition as it read at those times and that legislative history provides guidance in interpreting this provision.[307] In addition, although

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[307] In the 1970 CAAA, Congress defined "standard of performance," under § 111(a)(1), as:

> 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) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the "best system of emission reduction . . . adequately demonstrated," the "best technological system of continuous emission reduction . . . adequately demonstrated;" and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider "any nondairy quality health and environmental impact and energy requirements."

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of § 111(a)(1) that the standard of performance be based on the "best system of emission reduction . . . adequately demonstrated." This 1990 CAAA version is the current definition, which is applicable at present. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the

the D.C. Circuit has never reviewed a section 111(d) rulemaking, the Court has reviewed section 111(b) rulemakings on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[308] through which the Court has developed a body of case law that interprets the term "standard of performance."

c. Key elements of interpretation. The emission guidelines promulgated by the Administrator must include emission limitations that are "achievable" by the source category by application of a "system of emission reduction" that is "adequately demonstrated" and that the EPA determines to be the "best," "taking into account" the factors of "cost. . . nonair quality health and environmental impact and energy requirements." The D.C. Circuit has stated that in determining the "best" system, the EPA must also take into account "the amount of air pollution"[309] reduced and the role of "technological innovation."[310] The

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interpretation, in the case law, of those parts of the definition remain relevant to the definition as it reads today.

[308] *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, (D.C. Cir. 1973); *Portland Cement Ass'n* v. *EPA*, 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware* v. *EPA*, No. 13-1093 (D.C. Cir. May 1, 2015).

[309] *See Sierra Club* v. *Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

[310] *See Sierra Club* v. *Costle*, 657 F.2d at 347.

Court has emphasized that the EPA has discretion in weighing those various factors.[311] [312]

Our overall approach to determining the BSER and emission guidelines, which incorporates the various elements, is as follows: In developing an emission guideline, we generally engage in an analytical approach that is similar to what we conduct under CAA section 111(b) for new sources. First, we identify "system[s] of emission reduction" that have been "adequately demonstrated" for a particular source category. Second, we determine the "best" of these systems after evaluating the amount of reductions, costs, any nonair health and environmental impacts, energy requirements, and, in the alternative, the advancement of technology (that is, we apply a formulation of the BSER with the above noted factors, and then, in the alternative, we apply a formulation of the BSER with those same factors plus the

[311] *See Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[312] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the "adequately demonstrated" determination, the D.C. Circuit's case law appears to treat them as part of the "best" determination. *See Sierra Club* v. *Costle*, 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority "when determining the best technological system to weigh cost, energy, and environmental impacts"). Nevertheless, it does not appear that those two approaches would lead to different outcomes. *See, e.g.*, *Lignite Energy Council* v. *EPA*, 198 F.3d at 933 (rejecting challenge to the EPA's cost assessment of the "best demonstrated system"). In this rule, the EPA treats the factors as part of the "best" determination, but, as noted, even if the factors were part of the "adequately demonstrated" determination, our analysis and outcome would be the same.

advancement of technology). And third, we select an achievable emission limit—here, the emission performance rates—based on the BSER.[313] In contrast to subsection (b), however, subsection (d)(1) assigns to the states, not the EPA, the obligation of setting standards of performance for the affected sources. As discussed below in the following subsection, in examining the range of reasonable options for states to consider in setting standards of performance under these guidelines, we identified a number of considerations, including the interconnected operations of the affected sources and the characteristics of the CO_2 pollutant.

The remainder of this subsection discusses the various elements in our general analytical approach.

(1) System of Emission Reduction

As we discuss below, the CAA does not define the phrase "system of emission reduction." The ordinary, everyday meaning of "system" is a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[314] With this definition, the phrase "system

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[313] *See, e.g.*, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews, 77 FR 49490, 49494 (Aug. 16, 2012) (describing the three-step analysis in setting a standard of performance).

[314] *Oxford Dictionary of English* (3rd ed.) (2010), *available at http://www.oxforddictionaries.com/us/definition/american_english/system; see also* American Heritage Dictionary (5th ed.) (2013), *available at http://www.yourdictionary.com/system#americanheritage*; and *The American College Dictionary (C.L.*

of emission reduction" takes a broad meaning: a set of measures that work together to reduce emissions. The EPA interprets this phrase to carry an important limitation: Because the emission guidelines for the existing sources must reflect "the degree of emission limitation achievable *through the application of* the best system of emission reduction . . . adequately demonstrated," the system must be limited to measures that can be implemented—"appl[ied]"—by the sources themselves, that is, as a practical matter, by actions taken by the owners or operators of the sources. As we discuss below, this definition is sufficiently broad to include the building blocks.

(2) "Adequately Demonstrated"

Under section 111(a)(1), in order for a "system of emission reduction" to serve as the basis for an "achievable" emission limitation, the Administrator must determine that the system is "adequately demonstrated." This means, according to the D.C. Circuit, that the system is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[315] It does not mean that the system "must be in actual routine use somewhere."[316] Rather, the Court

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Barnhart, ed. 1970) ("an assemblage or combination of things or parts forming a complex or unitary whole").

[315] *Essex Chem. Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).

[316] *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and

has said, "[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry."[317] Similarly, the EPA may "hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible."[318] Ultimately, the analysis "is partially dependent on 'lead time,'" that is, "the time in which the technology will have to be available."[319] Unlike for CAA section 111(b) standards that are applicable immediately after the effective date of their promulgation, under CAA section 111(e), compliance with CAA section 111(d) standards may be set sometime in the future. This is due, in part, to the period of time for states to submit state plans and for the EPA to act on them.

(3) "Best"

In determining which adequately demonstrated system of emission reduction is the "best," the EPA considers the following factors:

(a) Costs

Under CAA section 111(a)(1), the EPA is required to take into account "the cost of achieving" the required emission reductions. As described in the January

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House bills and reports from which the language in CAA section 111 grew).

[317] Ibid.

[318] *Sierra Club* v. *Costle*, 657 F.2d 298, 364 (1981).

[319] *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

2014 proposal,[320] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be "exorbitant,"[321] "greater than the industry could bear and survive,"[322] "excessive,"[323] or "unreasonable."[324] These formulations appear to be synonymous, and for convenience, in this rulemaking, we will use reasonableness as the standard, so that a control technology may be considered the "best system of emission reduction . . . adequately demonstrated" if its

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[320] 79 FR 1430, 1464 (January 8, 2014).

[321] *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

[322] *Portland Cement Ass'n* v. *EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).

[323] *Sierra Club* v. *Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).

[324] *Sierra Club* v. *Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).

costs are reasonable, but cannot be considered the best system if its costs are unreasonable.[325] [326]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view that "the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal

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[325] These cost formulations are consistent with the legislative history of section 111. The 1977 House Committee Report noted:

> In the [1970] Congress [*sic*: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

> The implicit consideration of economic factors in determining whether technology is "available" should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91-1196 at 16.

[326] We received comments that we do not have authority to revise the cost standard as established in the case law, *e.g.*, "exorbitant," "excessive," etc., to a "reasonableness" standard that the commenters considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as "reasonableness" is intended to be a convenient term for referring to the cost standard as established in the case law.

and proper expense of doing business."[327] *See Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, 440 (D.C. Cir. 1973);[328] *Portland Cement Association* v. *Ruckelshaus*, 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle*, 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the "cost of the new controls . . . is substantial").[329]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis.

(b) Non-Air Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account "any nonair quality health and environmental impact" in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be "best" if it does more harm than good due to cross-media environmental impacts.[330]

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[327] 1977 House Committee Report at 184.

[328] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

[329] Indeed, in upholding the EPA's consideration of costs under other provisions requiring consideration of cost, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA*, 870 F. 2d 177, 251 (5th Cir. 1989); Am. Iron & *Steel Inst.* v. *EPA*, 526 F. 2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA*, 615 F. 2d 794, 808 (9th Cir. 1980).

[330] *Portland Cement* v. *EPA*, 486 F. 2d at 384; *Sierra Club* v. *Costle*, 657 F. 2d at 331; *see also Essex Chemical Corp.* v. *Ruckelshaus*, 486 F. 2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

(c) Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account "energy requirements." As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, "energy requirements" entails, for example, the impact, if any, of the system of emission reduction on the source's own energy needs.

(d) Amount of Emissions Reductions

In the proposed rulemakings for this rule and the associated section 111(b) rule, we noted that although the definition of "standard of performance" does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the "best system of emission reduction," the D.C. Circuit has stated that the EPA must do so. *See Sierra Club* v. *Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981) ("we can think of no sensible interpretation of the statutory words "best . . . system" which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions").[331] The fact

[331] *Sierra Club* v. *Costle*, 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of "standard of performance," which revised the phrase "best system of emission reduction" to read, "best technological system of continuous emission reduction." As noted above, the 1990 CAAA deleted "technological" and "continuous" and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions remains

that the purpose of a "system of emission reduction" is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a "system of emission reduction" is the "best," the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term "system of emission reduction" or the term "best" may reasonably be read to allow that discretion.

(e) Sector- or Nationwide Component of Factors in Determining the BSER

As discussed in the January 2014 proposal for the section 111(b) rulemaking and the proposal for this rulemaking, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[332] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club* v. *Costle* case, which concerned the NSPS for new power plants—on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a

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valid for the 1990 CAAA phrase "best system of emission reduction."

[332] 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle*, 657 F.2d at 351).

> broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[333]

The Court has upheld EPA rules that the EPA "justified . . . in terms of the policies of the Act," including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties . . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
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> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[334]

In this rule, the EPA is considering costs and energy implications on the basis of (i) their source-specific

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[333] *Sierra Club* v. *Costle*, 657 F.2d at 331 (citations omitted) (citing legislative history).

[334] *Sierra Club* v. *Costle*, 657 F.2d at 327–28 (quoting 44 FR at 33583/3–33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club* v. *Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

impacts and (ii) a sector-wide, regional, or national basis, both separately and in combination with each other.

(4) Achievability of the Emission Limitation in the Emission Guidelines

Before discussing the requirement under section 111(d) that the emission limitation in the emission guidelines must be "achievable," it is useful to discuss the comparable requirement under section 111(b) for new sources. For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish "standards of performance," which are standards for emissions that reflect the degree of emission limitation that is "achievable" through the application of the BSER. According to the D.C. Circuit, a standard of performance is "achievable" if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[335] Moreover, according to the Court, "[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."[336] To be achievable, a standard "must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into

[335] *Sierra Club* v. *Costle*, 657 F.2d 298, 364, n. 276 (D.C. Cir. 1981).

[336] *Essex Chem. Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974).

account in determining the 'costs' of compliance."[337] To show a standard is achievable, the EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[338]

The D.C. Circuit established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance. There is no case law under CAA section 111(d). Assuming that those standards for achievability apply under section 111(d), in this rulemaking, we are taking a similar approach for the emission limitation that the EPA identifies in the emission guidelines. For existing sources, section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include "standards of performance." Through long-standing regulations[339] and consistent practice, the EPA has interpreted this provision to require the EPA to

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[337] *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[338] *Sierra Club* v. *Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the "'feedstock, operation, size and age' of the source." *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to "generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters." *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[339] 40 CFR 60.21(e).

promulgate emission guidelines that determine the BSER for a source category and that identify the amount of emission limitation achievable by application of the BSER.

The EPA has promulgated these emission guidelines on the basis that the existing sources can achieve the limitation, even though the state retains discretion to apply standards of performance to individual sources that are more or less stringent.

As indicated in the proposed rulemakings for this rule and the associated section 111(b) rule, the requirement that the emission limitation in the emission guidelines be "achievable" based on the "best system of emission reduction . . . adequately demonstrated" indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible. *See* 79 FR 1430, 1463 (January 8, 2014). At least in some cases, in determining whether the emission limitation is achievable, it is useful to analyze the technical feasibility of the system of emission reduction, and we do so in this rulemaking.

(5) Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the "best system of emission reduction." *See Sierra Club* v. *Costle*, 657 F.2d at 346–47. The Court has grounded its reading in the statutory text.[340] In addition, the Court's

[340] *Sierra Club* v. *Costle*, 657 F. 2d at 346 ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces

interpretation finds firm support in the legislative history.[341] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the "best system of emission reduction . . . adequately demonstrated;" under section 111(a)(1);[342] (ii) the expanded use of the best demonstrated technology;[343] and (iii) the development of emerging technology.[344] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to

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consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.").

[341] *See* S. Rep. No. 91-1196 at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources"); S. Rep. No. 95-127 at 17 (1977) (cited in *Sierra Club* v. *Costle*, 657 F.2d at 346 n. 174) ("The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology").

[342] *See Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must "look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present").

[343] *See* 1970 Senate Committee Report No. 91-1196 at 15 ("The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems").

[344] *See Sierra Club* v. *Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

consider it, either because technological innovation may be considered an element of the term "best," or because the term "best system of emission reduction" is ambiguous as to whether technological innovation may be considered, and it is reasonable for the EPA to interpret it to authorize consideration of technological innovation in light of Congress's emphasis on technological innovation.

In any event, as discussed below, the EPA may justify the control measures identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

(6) EPA Discretion

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club* v. *Costle*, 657 F.2d 298 (D.C. Cir. 1981), the Court explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,"[345] and emphasized that "[t]he text gives the EPA broad discretion to weigh different factors in setting the standard."[346] In *Lignite Energy Council* v. *EPA*, 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these

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[345] *Sierra Club* v. *Costle*, 657 F.2d at 319.

[346] *Sierra Club* v. *Costle*, 657 F.2d at 321; *see also New York* v. *Reilly*, 969 F.2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, "the Administrator is free to exercise [her] discretion" in promulgating an NSPS).

> factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[347]

d. *Approach to the source category and subcategorizing.* Section 111 requires the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category. Section 111(b)(2) grants the EPA discretion whether to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which we refer to as "subcategorizing." Section 111(d)(1), in conjunction with section 111(a)(1), simply requires the EPA to determine the BSER, does not prescribe the method for doing so, and is silent as to whether the EPA may subcategorize. The EPA interprets this provision to authorize the EPA to exercise discretion as to whether and, if so, how to subcategorize. In addition, the regulations under CAA section 111(d)

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[347] *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). *See New York* v. *Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992) ("Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area."); *see also NRDC* v. *EPA*, 25 F.3d 1063, 1071 (D.C. Cir. 1994) (EPA did not err in its final balancing because "neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decision making.").

provide that the Administrator will specify different emission guidelines or compliance times or both “for different sizes, types, and classes of designated facilities when costs of the control, physical limitations, geographical location, or similar factors make subcategorization appropriate.”[348]

As with any of its own regulations, the EPA has authority to interpret or revise these regulations.

Of course, regardless of whether the EPA subcategorizes within a source category for purposes of determining the BSER and the emissions performance level for the emission guideline, as part of its CAA section 111(d) plan, a state retains great flexibility in assigning standards of performance to its affected EGUs. Thus, the state may, if it wishes, impose different emission reduction obligations on different sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines.

2. The BSER for This Rule—Overview

a. *Summary*. This section describes the EPA’s overall approach to establishing the BSER. This rule, promulgated under CAA section 111(d), establishes emission guidelines for states to use in establishing standards of performance for affected EGUs, and the BSER is the central determination that the EPA must make in formulating the guidelines. In order to establish the BSER we have considered the subcategory of the steam affected EGUs as a whole, and the subcategory of the combustion turbine affected EGUs as a whole, and have identified the

[348] 40 CFR 60.22(b)(5).

BSER for each subcategory as the measures that the sources, viewed together and operating under the standards of performance established for them by the states, can implement to reduce their emissions to an appropriate amount, and that meet the other requirements for the BSER including, for example, cost reasonableness.[349] After identifying the BSER in this manner, the EPA determines the performance levels—in this case, the CO_2 emission performance rates—for the steam generators and for the combustion turbines.

In establishing the BSER the EPA also considered the set of actions that an EGU, operating under a standard of performance established by its state, may take to achieve the applicable performance rate, if the state adopts that rate as the standard of performance and applies it to the EGUs in its jurisdiction, or to achieve the equivalent mass-based limit, and that meet the other requirements for the BSER. These actions implement the BSER and may therefore be understood as part of the BSER.

An example illustrating the relationship between the measures determined to constitute the BSER for the source category and the actions that may be undertaken by individual sources that are therefore also part of the BSER is the substitution of zero-emitting generation for CO_2-emitting generation. This

[349] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, *e.g.*, "exorbitant," "excessive," etc., or through the term we use for convenience, "reasonableness".

measure involves two distinct actions: Increasing the amount of zero-emitting generation and reducing the amount of CO_2-emitting generation. From the perspective of the source category, the two actions are halves of a single balanced endeavor, but from the perspective of any individual affected EGU, the two actions are separable, and a particular affected EGU may decide to implement either or both of the actions. Further, an individual source may choose to invest directly in actions at its own facility or an affiliated facility or to cross-invest in actions at other facilities on the interconnected electricity system.

To reiterate the overall context for the BSER: In this rule, the EPA determined the BSER, and applied it to the category of affected EGUs to determine the performance levels—that is, the CO_2 emission performance rates—for steam generators and for combustion turbines. States must impose standards of performance on their sources that implement the CO_2 emission performance rates, or, as an alternative method of compliance, in total, achieve the equivalent emissions performance level that the CO_2 emission performance rates would achieve if applied directly to each source as the standard or emissions limitation it must meet.[350] Each state has flexibility in how it assigns the emission limitations to its affected EGUs—and in fact, the state can be more stringent than the guidelines require—but one of the state's choices is to convert the CO_2 emission performance rates into standards of performance—which may incorporate emissions trading—for each of its affected

[350] The approaches that states may take in their plans are discussed in section VIII.

EGUs. If a state does so, then the affected EGUs may achieve their emission limits by taking the actions that qualify as the BSER. Since the BSER and, in this case its constituent elements, reflect the criteria of reasonable cost and other BSER criteria, the BSER assures that there is at least one pathway—the CO_2 emission performance rates—for the state and its affected EGUs to take that achieves the requisite level of emission reductions, while, again, assuring that the affected EGUs can achieve those emission limits at reasonable cost and consistent with the other factors for the BSER.

This section describes the EPA's process and basis for determining the BSER for the purpose of determining the CO_2 emission performance rates.[351] The EPA is identifying the BSER as a well-established set of measures that have been used by EGUs for many years to achieve various business and policy purposes, and have been used in recent years for the specific purpose of reducing EGUs' CO_2 emissions, and that are appropriate for carbon pollution (given its global nature and large quantities, and the limited means to control it) and afforded by the highly integrated nature of the utility power sector. We evaluated these measures with a view to the states' obligation to establish standards of performance and included in our BSER determination consideration of the range of options available for states to employ in establishing those standards of performance. These measures include: (i) Improving heat rate at existing

[351] Other sections in this preamble describe how EPA calculated the CO_2 emission performance rates based on the BSER.

coal-fired steam EGUs on average by a specified percentage (building block 1); (ii) substituting increased generation from existing NGCC units for reduced generation at existing steam EGUs in specified amounts (building block 2); and (iii) substituting increased generation from new zero-emitting RE generating capacity for reduced generation at existing fossil fuel-fired EGUs in specified amounts (building block 3). It should be noted that building block 2 incorporates reduced generation from steam EGUs and building block 3 incorporates reduced generation from all fossil fuel-fired EGUs.[352] Further, as discussed below, given the global nature of carbon pollution and the highly integrated utility power sector, each of the building blocks incorporates various mechanisms for facilitating cross-investment by individual affected EGUs in emission rate improvements or emission reduction activities at other locations on the interconnected electricity system. The range of mechanisms includes bilateral investment of various kinds; the issuance and acquisition of ERCs representing the emissions-reducing effects of specific activities, where available under state plans; and more general emissions trading using rate-based credits or mass-based allowances (as discussed in section V.A.2.f. below), where the affected EGUs are

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[352] The building block measures are not designed to reduce electricity generation overall; they are focused on maintaining the same level of electricity generation, but through less polluting processes.

operating under standards of performance that incorporate emissions trading.[353]

The set of measures identified as the BSER for the source category encompasses a menu of actions that are part of the BSER and that individual affected EGUs may implement in different amounts and combinations in order to achieve their emission limits at reasonable cost. This menu includes actions that: (i) Affected steam EGUs can implement to improve their heat rates; (ii) affected steam EGUs can implement to increase generation from lower-emitting existing NGCC units in specified amounts; (iii) all affected EGUs can implement to increase generation from new low- or zero-carbon generation sources in specified amounts; (iv) all affected EGUs can implement to reduce their generation in specified amounts; and (v) all affected EGUs operating under a standard of performance that incorporates emissions trading can implement by means of purchasing rate-based emission credits or mass-based emission allowances from other affected EGUs, since the effect of the purchase would be the same as achieving the other listed actions through direct means.[354]

Importantly, affected EGUs also have available numerous other measures that are not included in the BSER but that could materially help the EGUs achieve their emission limits and thereby provide compliance flexibility. Examples include, among numerous other approaches, investment in demand-

[353] Conditions for the use of these mechanisms under various state plans are discussed in section VIII.

[354] Again, conditions for the use of these mechanisms under various state plans are discussed in section VIII.

side EE, co-firing with natural gas (for coal-fired steam EGUs), and investment in new generating units using low- or zero-carbon generating technologies other than those that are part of building block 3.

b. *The EPA's review of measures for determining the BSER*. The EPA described in the proposal for this rule the analytical process by which the EPA determined the BSER for this source category. The EPA is finalizing large parts of that analysis, but the EPA is also refining that analysis as informed by the information and data discussed by commenters and our further evaluation. What follows is the EPA's final determination.

As described in the proposal, to determine the BSER, the EPA began by considering the characteristics of CO_2 pollution and the utility power sector. Not surprisingly, whenever the EPA begins the regulatory process under section 111, it initially undertakes these same inquiries and then proceeds to fashion the rule to fit the industry. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs.[355] In assessing the final SO_2

[355] The need for new standards was due in part to findings that in 1976, steam electric generating units were responsible for "65 percent of the SO_2 . . . emissions on a national basis."44 FR 33580, 33587 (June 11, 1979). The EPA explained that [u]nder the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 17 percent between 1975 and 1995. Impacts will be more dramatic on a regional basis." *Id.* Thus, "[o]n January 27, 1977, EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to

standard, the EPA carried out extensive analyses of a range of alternative SO_2 standards "to identify environmental, economic, and energy impacts associated with each of the alternatives considered at the national and regional levels."[356] In identifying the best system underlying the final standard, the EPA evaluated "coal cleaning and the relative economics of FGD [flue gas desulfurization] and coal cleaning" together as the "best demonstrated system for SO_2 emission reduction."[357] The EPA also took into account the unique features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[358]

Similarly, in 1996, the EPA finalized section 111(b) standards and 111(d) emission guidelines to ensure that certain municipal solid waste (MSW) landfills controlled landfill gases to the level achievable through application of the BSER.[359] EPA's

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what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised." *Id.* at 33587–33588.

[356] 44 FR 33580, 33582 (June 11, 1979).

[357] 44 FR 33580, 33593. The EPA considered an investigation by the U.S. Department of the Interior regarding the amount of sulfur that could be removed from various coals by physical coal cleaning. *Id.* at 33593.

[358] *See* 44 FR 33580, 33597–33600 (taking into account "the amount of power that could be purchased from neighboring interconnected utility companies" and noting that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations" and that "load can usually be shifted to other electric generating units").

[359] 61 FR 9905, 9905 (March 12, 1996). In the rule, the EPA referred to the BSER for both new and existing MSW landfills as "the best demonstrated system of continuous emission reduction,"

identification of this BSER was critically influenced by the "unique emission pattern of landfills."[360] Unlike "typical stationary source[s]," which only generate emissions while in operation, MSW landfills can "continue to generate and emit a significant quantity of emissions" long after the facility has closed or otherwise stopped accepting waste.[361] In recognition of this salient and unique characteristic of landfills, the EPA set the BSER based on an emission-reducing system of gas collection and control that remained in place as long as emissions remained above a certain threshold—even after the regulated landfill had permanently closed.[362] The EPA acknowledged that for some landfills, it could take 50 to 100 years for emissions to drop below the cutoff.[363]

For this rule, we discuss at length in the proposed rule and in section II above the unique characteristics of CO_2 pollution. The salient facts include the global nature of CO_2, which makes the specific location of

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as well as the "BDT"—short for "best demonstrated technology." *See, e.g.*, *id.* at 9905–07, 9913–14.

[360] 61 FR 9905, 9908; see 56 FR 24468, 24478 (May 30, 1991) (explaining at proposal that because landfill-gas emission rates "gradually increase" from zero after the landfill opens, and "gradually decrease" from peak emissions after closure, the EPA's identification of the BSER for landfills inherently requires a determination of "when controls systems must be installed and when they may be removed')).

[361] *See* U.S. EPA, *Municipal Solid Waste Landfills, Volume 1: Summary of the Requirements for the New Source Performance Standards and Emission Guidelines for Municipal Solid Waste Landfills*, Docket No. EPA-453R/96-004 at 1–3 (February 1999).

[362] 61 FR 9905, 9907–08.

[363] 61 FR 9905, 9908.

emission reductions unimportant; the enormous quantities of CO_2 emitted by the utility power sector, coupled with the fact that CO_2 is relatively unreactive, which make CO_2 much more difficult to mitigate by measures or technologies that are typically utilized within an existing power plant; the need to make large reductions of CO_2 in order to protect human health and the environment; and the fact that the utility power sector is the single largest source category by a considerable margin.

We also discuss at length in the proposal and in section II above the unique characteristics of the utility power sector. Topics of that discussion include the physical properties of electricity and the integrated nature of the electricity system. Here, we reiterate and emphasize that the utility power sector is unique in the extent to which it must balance supply and demand on a real-time basis, with limited electricity storage capacity to act as a buffer. In turn, the need for real-time synchronization across each interconnection has led to a uniquely high degree of coordination and interdependence in both planning and real-time system operation among the owners and operators of the facilities comprised within each of the three large electrical interconnections covering the contiguous 48 states. Given these unique characteristics, it is not surprising that the North American power system has been characterized as a "complex machine."[364] The core function of providing reliable electricity service is carried out not by

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[364] S. Massoud Amin, "Securing the Electricity Grid," The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).

individual electricity generating units but by the complex machine as a whole. Important subsidiary functions such as management of costs and management of environmental impacts are also carried out to a great extent on a multi-unit basis rather than an individual-unit basis. Generation from one generating unit can be and routinely is substituted for generation from another generating unit in order to keep the complex machine operating while observing the machine's technical, environmental, and other constraints and managing its costs.

The EPA also reviewed broad trends within the utility power sector.[365] It is evident that, in the recent past, coal-fired electricity generation has been reduced, and projected future trends are for continued reduction. By the same token, lower-emitting NGCC generation and renewable generation have increased, and projected future trends are for continued increases.[366] A survey of integrated resource plans (IRPs), included in the docket, shows that fossil fuel-fired EGUs are taking actions to reduce emissions of both non-GHG air pollutants and GHGs.[367] Some fossil fuel-fired EGUs are investing in lower- or zero-emitting generation. In fact, our review indicates that the great majority of fossil fuel-fired generators surveyed are including new RE resources in their

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[365] These trends are discussed in more detail in sections V.D. and V.E. below.

[366] Demand-side energy efficiency measures have also increased, and the projected future trends are for continued increase.

[367] See memorandum entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

planning. In addition, some fossil fuel-fired EGUs are using those measures to replace their higher-emitting generation. Some fossil fuel-fired generators appear to be reducing their higher-emitting generation without fully replacing it themselves. These measures in aggregate result in the replacement of higher-emitting generation with lower- or zero-emitting generation, reflecting the integrated nature of the electricity system.

The EPA examined state and company programs intended at least in part to reduce CO_2 from fossil fuel-fired power plants. These programs include GHG performance standards established by states including California, New York, Oregon, and Washington; utility planning approaches carried out by companies in Colorado and Minnesota; and renewable portfolio standards (RPS) established in more than 25 states.[368] They also include market-based initiatives, such as RGGI and the GHG emissions trading program established by the California Global Warming Solutions Act, and conservation and demand reduction programs.

We also examined federal legislative and regulatory programs, as well as state programs currently in operation, that address pollutants other than CO_2 emitted by the power sector. These programs include, among others, the CAA Title IV program to reduce SO_2 and NO_X, the MATS program to reduce mercury and air toxic emissions, and the CSAPR program to reduce SO_2 and NO_X.[369] This analysis demonstrated that,

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[368] *See* 79 FR 34848–34850.

[369] Many of these programs are discussed in section II.

among other measures, the application of control technology, fuel-switching, and improvements in the operational efficiency of EGUs all resulted in reductions in a range of pollutants. These programs also demonstrate that replacement of higher-emitting generation with lower-emitting generation—including generation shifts between coal-fired EGUs and natural gas-fired EGUs and generation shifts between fossil fuel-fired EGUs and RE generation—also reduces emissions. Some of these programs also include emissions trading among the power plants.

In this rule, when evaluating the types and amounts of measures that the source category can take to reduce CO_2 emissions, we have appropriately taken into account the global nature of the pollutant and the high degree to which each individual affected EGU is integrated into a "complex machine" that makes it possible for generation from one generating unit to be replaced with generation from another generating unit for the purpose of reducing generation from CO_2-emitting generating units. We have also taken into account the trends away from higher-carbon generation toward lower- and zero-carbon generation. These factors strongly support consideration of emission reduction approaches that focus on the machine as a whole—that is, the overall source category—by shifting generation from dirtier to cleaner sources in addition to emission reduction approaches that focus on improving the emission rates of individual sources.

The factors just discussed that support consideration of emission reduction measures at the source-category level likewise strongly support consideration of mechanisms such as emissions trading approaches, especially since, as discussed in section VIII, the states will have every opportunity to design their section 111(d) plans to allow the affected EGUs in their respective jurisdictions to employ emissions trading approaches to achieve the standards of performance established in those plans. In short, as discussed in more detail in section V.A.2.f. below, it is entirely feasible for states to establish standards of performance that incorporate emissions trading, and it is reasonable to expect that states will do so. These approaches lower overall costs, add flexibility, and make it easier for individual sources to address pollution control objectives. To the extent that the purchase of an emissions credit or allowance represents the purchase of surplus emission reductions by an emitting source, emissions trading represents, in effect, the investment in pollution control by the purchasing source, notwithstanding that the control activity may be occurring at another source. As noted above, the utility power sector has a long history of using the "complex machine" to address objectives and constraints of various kinds. When afforded the opportunity to address environmental objectives on a multi-unit basis, the industry has done so. Congress and the EPA have selected emissions trading approaches when addressing regional pollution from the utility power sector contributing to problems such as acid precipitation and interstate transport of ozone and particulate matter. Similarly, states have selected market-based approaches for their own programs to address regional and global pollutants. The industry has readily adapted to that form of regulation, taking advantage of the flexibility and incorporating those programs into the planning and operation of the "machine." Further reinforcing our conclusion that reliance on trading is appropriate is the extensive interest in using such mechanisms that states and utilities demonstrated through their formal comments and in discussions during the outreach process. The role of emissions trading is discussed further in section V.A.2.f. below.

This entire review has made clear that there are numerous measures that, alone or in various combinations, merit analysis for inclusion in the BSER. The review has also made clear that the unique characteristics of CO_2 pollution and the unique, interconnected and interdependent manner in which affected EGUs and other generating sources operate within the electricity sector make certain types of measures and mechanisms available and appropriate for consideration as the BSER for this rule that would not be appropriate for other pollutants and other industrial sectors. For purposes of this discussion, the measures can be categorized in terms of the essential characteristics of the four building blocks described in the proposal: measures that (i) reduce the CO_2 emission rate at the unit; (ii) substitute generation from existing lower-emitting fossil fuel-fired units for generation from higher-emitting fossil fuel-fired units; (iii) substitute generation from new low- or zero-emitting generating capacity, especially RE, for generation from fossil fuel-fired units; and (iv) increase demand-side EE to avoid generation from fossil fuel-fired units. In the proposal, we described our evaluations of various measures in each of these categories. In this rule, with the benefit of comments, we have refined our evaluation of which specific measures should comprise the first three building blocks, and, for reasons discussed below, we have determined that the fourth building block, demand-side EE, should not be included in the BSER in these guidelines.

The measures are discussed more fully below, but it should be noted here that because of the integrated nature of the utility power sector—in which individual EGUs' operations intrinsically depend on the operations of other generators—coupled with the sector's high degree of planning and reliability safeguards, the measures in the second and third categories (which involve generation shifts to lower- and zero-emitting sources) may occur through several different actions from the perspective of an individual source, all of which are equivalent from the perspective of the source category as a whole. First, a higher-emitting fossil unit may invest in cleaner generation without reducing its own generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in less demand for, and therefore reductions in generation by, other higher-emitting units. Second, a higher-emitting fossil unit may reduce its generation, which, in the presence of requirements for the source category as a whole to reduce CO_2 emissions, would result in increased demand for, and therefore increased amounts of, cleaner generation. Third, a higher-emitting fossil unit may do both of these things, directly replacing part of its generation with investments in lower- or zero-emitting generation. In addition, for measures in all of the categories, multiple mechanisms exist by which an individual affected EGU may make these investments, ranging from bilateral investments, to purchase of credits representing the emissions-reducing benefits of specific activities, to purchase of general rate-based emissions credits or mass-based emission allowances. As discussed below, mechanisms involving tradable credits or allowances are well within the realm of consideration for the standards of performance states can choose to apply to their EGUs and hence, are entirely appropriate for EPA to consider in evaluating these measures in the course of making its BSER determination.

c. *State establishment of standards of performance and source compliance.* Before identifying in detail the measures that the BSER comprises, it is useful to describe the process by which the states establish the standards of performance with which the affected EGUs must comply, and the implications for the sources that will be operating subject to those standards of performance. As part of the EPA's emission guidelines in this rule, and based on the BSER, the EPA is identifying CO_2 emission performance rates that reflect the BSER and, pursuant to subsection 111(d)(1), requiring states to establish standards of performance for affected EGUs in order to implement those rates. States, of course, could simply impose those rates on each affected EGU in their respective jurisdictions, but we are also offering states alternative approaches to carrying out their obligations. For purposes of defining these alternatives and facilitating states' efforts to formulate compliance plans encompassing maximum flexibilities, we are aggregating the performance rates into goals for each state. The state, in turn, has the option of setting specific standards of performance for its EGUs such that the emission limitations from the

EGUs operating under those standards of performance together meet the performance rates or the state goal. To do this, the state must adopt a plan that establishes the EGUs' standards of performance and that implements and enforces those standards.

Each state has significant flexibility in several respects. For example, as mentioned, a state may impose standards of performance on its steam EGU sources and on its combustion turbine sources that simply reflect the respective CO_2 emission performance rates for those subcategories set in the emission guidelines. Alternatively, a state may impose standards with differing degrees of stringency on various sources, and, in fact, may be more stringent overall than its state goal requires. In addition—and most importantly for purposes of describing the BSER—a state may set standards of performance as mass limits (*e.g.*, tons of CO_2 per year) rather than as emission rates (*e.g.*, lbs of CO_2 per MWh). Moreover, a state may make the limits tradable (subject to conditions described in section VIII below), whether the limits are rate-based or mass-based. The form of the emission limits, whether emission rate limits or mass limits, has implications for what specific actions that are part of the BSER the individual affected EGUs may take to achieve those limits as well as what specific non-BSER measures are available to the individual affected EGUs for compliance flexibility. For example, if an individual source chooses to adopt building block 3 by both investing in lower- or zero-emitting generation and reducing its own generation, both those actions will be accounted for in its emission rate and both will therefore help the source meet its rate-based limit. If the same individual source takes the same actions but is subject to a mass-based limit, the action of reducing its generation will directly count in helping the source meet its own mass-based limit but the action of investing in cleaner generation will not. However, the investment in lower-or zero-emitting generation by that source and other sources collectively will help the overall source category achieve the emission limits consistent with the BSER and in doing so will make it easier for that source and other sources collectively to meet their mass-based limits.

In instances where a state establishes standards of performance that incorporate emissions trading, the tradable credits or allowances can serve as a medium through which affected EGUs can invest in any emission reduction measure.

d. *Identification of the BSER measures.* We now discuss the evaluation of potential measures for inclusion in the BSER for the source category as a whole.

(1) *Measures that reduce individual affected EGUs' CO_2 emission rates.*

As described in the proposal, the measures that the affected EGUs could implement to improve their CO_2 emission rates include a set of measures that the EPA determined would result in improvements in heat rate at coal-fired steam EGUs in the amount of 6 percent on average, and the EPA proposed that this set of measures qualifies as a component of the BSER. In this final rule, the EPA concludes that those measures do qualify as a component of the BSER. However, as described in section V.C. below, based on responsive comments and further evaluation, the EPA has refined its approach to quantifying the emission reductions achievable through heat rate improvements and no longer includes a separate increment of emission reductions attributable to equipment upgrades. Also, rather than evaluating the emission reductions available from these measures on a nationwide basis as in the proposal, the EPA has quantified the emission reductions achievable through building block 1 on a regional basis, consistent with the EPA's proposals to better reflect the regional nature of the interconnected electrical system and the treatment of the other building blocks in this final rule. As a result of these refinements, the EPA is identifying the heat rate improvements achievable by coal-fired steam EGUs as 4.3 percent for the Eastern Interconnection, 2.1 percent for the Western Interconnection, and 2.3 percent for the Texas Interconnection. The refinements are based, in significant part, on the numerous comments we received on our proposed approaches, especially those from states and utilities.

These heat rate improvement measures include best practices such as improved staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. These are measures that the owner/operator of an affected coal-fired steam EGU may take that would have the effect of reducing the amount of CO_2 the source emits per MWh. As a result, these measures would help the source achieve an emission limit expressed as either an emission rate limit or as a mass limit. We note again that in the context both of the integrated electricity system and of available and anticipated state approaches to setting standards of performance, emissions trading approaches could be used as mechanisms through which one affected EGU could invest in heat rate improvements at another EGU. We note this aspect below in describing the actions an individual affected EGU can take to implement the BSER and discuss it in more detail in section V.A.2.f.

These heat rate improvements are a low-cost option that fit the criteria for the BSER, except that they lead to only small emission reductions for the source category.[370] Given the magnitude of the environmental problem and projections by climate scientists that much larger emission reductions are needed from fossil fuel-fired EGUs to address climate change, the EPA looked at additional measures to reduce emission rates. This reflects our conclusion that, given the availability of other measures capable of much greater emission reductions, the emission reductions limited to this set of heat rate improvement measures would not meet one of the considerations critical to the BSER determination—the quantity of emissions reductions resulting from the application of these measures is too small for these measures to be the BSER by themselves for this source category.

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[370] As further discussed below, if heat rate improvements at coal-fired steam EGUs were implemented in isolation, without other measures to reduce CO_2 emissions, the heat rate improvements could lead to increases in competitiveness and utilization of the coal-fired EGUs—a so-called "rebound effect"—causing increases in CO_2 emissions that could partially or even entirely offset the CO_2 emission reductions achieved through the reductions in the amount of CO_2 emissions per MWh of generation.

Specifically, as described in the proposal, the EPA also considered co-firing (including 100 percent conversion) with natural gas, a measure that presented itself in part because of the recent increase in availability and reduction in price of natural gas, and the industry's consequent increase in reliance on natural gas.[371] The EPA also considered implementation of carbon capture and storage (CCS).[372] The EPA found that some of these co-firing and CCS measures are technically feasible and within price ranges that the EPA has found to be cost effective in the context of other GHG rules, that a segment of the source category may implement these measures, and that the resulting emission reductions could be potentially significant.

However, these co-firing and CCS measures are more expensive than other available measures for existing sources. This is because the integrated nature of the electricity system affords significantly lower cost options, ones that fossil fuel-fired power plants throughout the U.S. and in foreign nations are already using to reduce their CO_2 emissions.

The less expensive options include shifting generation to existing NGCC units—an option that has become particularly attractive in light of the increased availability and lower prices of natural gas—as well as shifting generation to new RE generating units. A comparison of the costs of converting an existing coal-fired boiler to burn 100

[371] The EPA further addressed co-firing in the October 30, 2014 NODA. 79 FR 64549–51.

[372] CCS is also sometimes referred to as carbon capture and sequestration.

percent natural gas compared to the cost of shifting generation to an existing NGCC unit illustrates this point. Because an NGCC unit burns natural gas significantly more efficiently than an affected steam EGU does, the cost of shifting generation from the steam EGU to an existing NGCC unit is significantly cheaper in most cases than more aggressive emission rate reduction measures at the steam EGU. As a result, as a practical matter, were the EPA to include co-firing and CCS in the BSER and promulgate performance standards accordingly, few EGUs would likely comply with their emission standards through co-firing and CCS; rather, the EGUs would rely on the lower cost options of substituting lower- or zero-emitting generation or, as a related matter, reducing generation.[373]

The EPA also considered heat rate improvement opportunities at oil- and gas-fired steam EGUs and NGCC units and found that the available emission reductions would likely be more expensive or too small to merit consideration as a material component of the BSER.

Thus, in reviewing the entire range of control options, it became clear that controlling CO_2 from affected EGUs at levels that are commensurate with the sector's contribution to GHG emissions and thus necessary to mitigate the dangers presented by climate change, could depend in part, but not primarily, on measures that improve efficiency at the power plants. Rather, most of the CO_2 controls need to come in the form of those other measures that are

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[373] Many EGUs would also rely on demand-side energy efficiency measures.

available to the utility power sector thanks specifically to the integrated nature of the electricity system, and that involve, in one form or another, replacement of higher emitting generation with lower- or zero-emitting generation.

Although the presence of lower-cost options that achieve the emission reduction goals means that the EPA is not identifying either natural gas co-firing or CCS at coal-fired steam EGUs, or heat rate improvements at other types of EGUs, as part of the BSER, those controls remain measures that some affected EGUs may be expected to implement and that as a result, will provide reductions that those affected EGUs may rely on to achieve their emission limits or may sell, through emissions trading, to other affected EGUs to achieve emission limits (to the extent permitted under the relevant section 111(d) plans). Another example of a non-BSER measure that an affected EGU in certain circumstances could choose to implement is the conversion of waste heat from electricity generation into useful thermal energy. The EPA further discusses the potential use of these non-BSER measures for compliance flexibility below.

The EPA's quantification of the CO_2 emission reductions achievable through heat rate improvements as a component of the BSER (building block 1) is discussed in section V.C. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(2) *Measures available because of the integrated electricity system.*

To determine the BSER that meets the expectations and requirements of the CAA, including the achievement of meaningful reductions of CO_2, the EPA turned next to the set of measures that presented themselves as a result of the fact that the operations of individual affected EGUs are interdependent on and integrated with one another and with the overall electricity system. Those are the measures in the categories represented in the proposal by building blocks 2, 3, and 4. This section discusses the components of the BSER that relate to building blocks 2 and 3, which the EPA is finalizing as components of the BSER. This section also discusses the measures comprising the proposed building block 4, which the EPA is not including in the BSER in this final rule.

It bears reiterating that the extent to which the operations of individual affected EGUs are integrated with one another and with the overall electricity system is a highly salient and unique attribute of this source category. Because of this integration, the individual sources in the source category operate through a network that physically connects them to each other and to their customers, an interconnectedness that is essential to their operation under the status quo and by all indications is projected to be augmented further on a continual basis in the future to address fundamental objectives of reliability assurance and cost reduction. This physical interconnectedness exists to serve a set of interlocking regimes that, to a substantial extent, determine, if not dictate, any given EGU's operations on a nearly moment-to-moment basis. In analyzing BSER from the perspective of the overall source category, because the affected EGUs are connected to each other operationally, a combination of dispatching and investment in lower- and zero-emitting generation allows the replacement of higher-emitting generation with lower-emitting and zero-emitting generation (measures in building blocks 2 and 3), and thereby reduces emissions while continuing to serve load.

As noted above, substitution of higher-emitting generation for lower- or zero-emitting generation may include reduced generation, depending on the specific action taken by the individual EGU. Likewise, when incorporated into standards of performance, emissions trading mechanisms may be readily used for implementing these building blocks. We discuss these aspects below in describing the actions that individual sources may take to implement the building blocks.

(a) *Substituting generation from lower-emitting affected EGUs for generation from higher-emitting affected EGUs.*

In the proposal, the EPA observed that substantial CO_2 emission reductions could be achieved at reasonable cost by increasing generation from existing NGCC units and commensurately reducing generation from steam EGUs. Because NGCC units produce much less CO_2 per MWh of generation than steam EGUs—typically less than half as much CO_2 as coal-fired steam EGUs, which account for most generation from steam EGUs—this generation shift reduces CO_2 emissions. We also noted that because NGCC units can generate as much as 46 percent more electricity from a given quantity of natural gas than a steam unit can, generation shifting from coal-fired steam EGUs to existing NGCC units is a more cost-effective strategy for reducing CO_2 emissions from the source category than converting coal-fired steam EGUs to combust natural gas or co-firing coal and natural gas in steam

EGUs. We proposed to find that shifting generation consistent with a 70 percent target utilization rate (based on nameplate capacity) for NGCC units was feasible and should be a component of the BSER.

As described in section V.D. below, analysis reflecting consideration of the many comments we received on the EPA's proposal with respect to this issue supports the inclusion of generation shifting from higher-emitting to lower-emitting EGUs as a component of the BSER. Shifting of generation among EGUs is an everyday occurrence within the integrated operations of the utility power sector that is used to ensure that electricity is provided to meet customer demands in the most economic manner consistent with system constraints. Generation shifting to lower-emitting units has been recognized as an approach for reducing emissions in other EPA rules such as CSAPR.

The EPA's analysis continues to show that the magnitude of emission reductions included in the proposed rule from generation shifting is achievable. In response to our request for comment on the proposed target utilization rates, some commenters stated that summer capacity ratings are a more appropriate basis upon which to compute a target utilization than nameplate capacity ratings used at proposal. We agree, and accordingly, using the same data on historical generation as at proposal, we have reanalyzed feasible NGCC utilization levels expressed in terms of summer capacity ratings and have found that a 75 target utilization rate based on summer capacity ratings is feasible.

The EPA is finalizing a determination that generation shift from higher-emitting affected EGUs to lower-emitting affected EGUs is a component of the BSER (building block 2). Our quantification of the associated emission reductions is discussed in section V.D. of this preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(b) *Substituting increased generation from new low- or zero-carbon generating capacity for generation from affected EGUs.*

Reducing generation from fossil fuel-fired EGUs and replacing it with generation from lower- or zero-emitting EGUs is another method for reducing CO_2 emissions from the utility power sector. In the proposal, the EPA identified RE generating capacity and nuclear generating capacity as potential sources of lower- or zero-CO_2 generation that could replace higher-CO_2 generation from affected EGUs.

(i) *Increased generation from new RE generating capacity.*

The EPA's survey of trends and actions already being taken in the utility power sector indicated that RE generating capacity and generation have grown rapidly in recent years, in part because of the environmental benefits of shifting away from fossil fuel-fired generation and in part because of improved economics of RE generation relative to fossil fuel-fired generation. It is clear that increasing the amount of new RE generating capacity and allowing the increased RE generation to replace generation from fossil fuel-fired EGUs can reduce CO_2 emissions from the affected source category. Accordingly, we proposed to include replacement of defined quantities of fossil generation by RE generation in the BSER.

The EPA is finalizing the determination that substitution of RE generation from new RE generating capacity is a component of the BSER but, with the benefit of comments responding to the EPA's proposals on regionalization and techno-economic analytic approaches, the EPA has adjusted the approach for determining the quantities of RE generation. As part of the adjustment in approach, we have also refocused the quantification solely on generation from new RE generating capacity rather than total (new and existing) RE generating capacity as in the proposal. Our quantification of the RE generation component of the BSER is discussed in section V.E. of the preamble and in the GHG Mitigation Measures TSD for the CPP Final Rule.

(ii) *Increased and preserved generation from nuclear generating capacity.*

In the June 2014 proposal, the EPA also identified the replacement of generation from fossil fuel-fired EGUs with generation from nuclear units as a potential approach for reducing CO_2 emissions from the affected source category. We proposed to include two elements of nuclear generation in the BSER: An element representing projected generation from nuclear units under construction; and an element representing preserved generation from existing nuclear generating capacity at risk of retirement, and we took comment on all aspects of these proposals.

Like generation from new RE generating capacity, generation from new nuclear generating capacity can clearly replace fossil fuel-fired generation and thereby reduce CO_2 emissions. However, there are also important differences between these types of low- or zero-CO_2 generation. Investments in new nuclear capacity are very large capital-intensive investments that require substantial lead times. By comparison, investments in new RE generating capacity are individually smaller and require shorter lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Accordingly, as described in section V.A.3., the EPA is not finalizing increased generation from under-construction nuclear capacity as a component of the BSER.

The EPA is likewise not finalizing the proposal to include a component representing preserved existing nuclear generation in the BSER. On further consideration, we believe it is inappropriate to base the BSER on elements that will not reduce CO_2 emissions from affected EGUs below current levels. Existing nuclear generation helps make existing CO_2 emissions lower than they would otherwise be, but will not further lower CO_2 emissions below current levels. Accordingly, as described in section V.A.3., the EPA is not finalizing preservation of generation from existing nuclear capacity as a component of the BSER.

(iii) *Generation from new NGCC units.*

New NGCC units—that is, units that had not commenced construction as of January 8, 2014, the date of publication of the proposed CO_2 standards of performance for new EGUs under section 111(b)—are not subject to the standards of performance that will be established for existing sources under section 111(d) plans based on the BSER determined in this final rule. In the June 2014 proposed emission guidelines for existing EGUs, the EPA solicited comment on whether to include this measure in the BSER. Commenters raised numerous concerns, and after consideration of the comments, we are not including replacement of generation from affected EGUs through the construction of new NGCC capacity in the BSER. In this section, we discuss the reasons for our approach.

The EPA did not include reduced generation from affected EGUs achieved through construction and operation of new NGCC capacity in the proposed BSER because we expected that the CO_2 emission reductions achieved through such actions would, on average, be more costly than CO_2 emission reductions achieved through the proposed BSER measures. However, our determination not to include new construction and operation of new NGCC capacity in the BSER in this final rule rests primarily on the achievable magnitude of emission reductions rather than costs.

Unlike emission reductions achieved through the use of any of the building blocks, emission reductions achieved through the use of new NGCC capacity require the construction of additional CO_2-emitting generating capacity, a consequence that is inconsistent with the long-term need to continue reducing CO_2 emissions beyond the reductions that will be achieved through this rule. New generating assets are planned and built for long lifetimes—frequently 40 years or more—that are likely longer than the expected remaining lifetimes of the steam EGUs whose CO_2 emissions would initially be displaced be the generation from the new NGCC units. The new capacity is likely to continue to emit CO_2 throughout these longer lifetimes, absent decisions to retire the units before the end of their planned lifetimes or to install CCS technology in the future at substantial additional cost. Because of the likelihood of CO_2 emissions for decades, the overall net emission reductions achievable through the construction and operation of new NGCC are less than for the measures including in the BSER, such as increased generation at existing NGCC capacity, which would be expected to reach the end of its useful life sooner than new NGCC capacity, or construction and operation of zero-emitting RE generating capacity. We view the production of long-term CO_2 emissions that otherwise would not be created as inconsistent with the BSER requirement that we consider the magnitude of emissions reductions that can be achieved. For this reason, we are not including replacement of generation from affected EGUs through the construction and operation of new NGCC capacity in the final BSER.

Commenters also raised a concern with the interrelation of section 111(b) and section 111(d). New NGCC capacity is distinguished from the other non-BSER measures discussed above by the fact that its CO_2 emissions would be subject to the CO_2 standards for new EGUs being established under section 111(b). Section 111 creates an express distinction between the sources subject to section 111(b) and the sources subject to section 111(d), and commenters expressed concern that to allow section 111(b) sources to play a direct role in setting the BSER under section 111(d) would be inconsistent with congressional intent to treat the two sets of sources separately. Section VIII of this preamble includes a discussion of ways to address new NGCC capacity in the context of different types of section 111(d) plans.

(c) *Increasing demand-side EE to avoid generation and emissions from fossil fuel-fired EGUs.*

The final category of approaches for reducing generation and CO_2 emissions from affected EGUs that the EPA considered in the proposal involves increasing demand-side EE. When demand-side EE is increased, energy consumers need less electricity in order to provide the same level of electricity-dependent services—*e.g.*, heating, cooling, lighting, and use of motors and electronic devices. Through the integrated electricity system, including the connection of customers to affected EGUs through the electricity grid, reduced demand for electricity, in turn, leads to reduced generation and reduced CO_2 emissions. Our examination of actions and trends underway in the utility power sector confirmed that investments in demand-side EE programs are increasing. We proposed to include avoidance of defined quantities of fossil fuel-fired generation through increased demand-side EE as a component of the BSER (proposed building block 4). However, we also took comment on which building blocks should comprise the BSER and on our determination as to whether each building block met the various statutory factors.

Commenters expressed a wide range of views on the proposed reliance on demand-side EE in the BSER. Some commenters strongly supported the proposal, with suggestions for improvements, while some commenters strongly opposed the proposal and took the position that it exceeded the EPA's legal authority. We do not address the merits of these comments here because, for the reasons discussed in section V.B.3.c.(8) below, we are not finalizing the proposal to include avoided generation achieved through demand-side EE as a component of the BSER. However, we note that most commenters also supported the use of demand-side EE for compliance whether or not it is used in determining the BSER, and we are allowing demand-side EE to be used for that purpose. (We also emphasize that the emission limitations reflective of the BSER are achievable even if aggregate generation is not reduced through demand-side EE.)

(3) *Further analysis to quantify the BSER.*

While the discussion above summarizes how and why the components of the BSER were determined in terms of qualitative characteristics, it still leaves a wide range of potential stringencies for the BSER. As explained in sections V.C., V.D., and V.E. below, discussing building blocks 1, 2, and 3 respectively, the EPA has determined a reasonable level of stringency for each of the building blocks rather than the maximum possible level of stringency. We have taken this approach in part to ensure that there is "headroom" within the BSER measures that provides greater assurance of the achievability of the BSER for the source category and for individual sources. We believe this approach is permissible under the CAA. Another aspect of our methodology for computing the CO_2 emission performance rates, further described in section V.A.3.f. and section VI, is that the CO_2 emission performance rate applicable to a given source subcategory in all three interconnections reflects the emission rate achievable by that source subcategory through application of the building blocks in the interconnection where that achievable emission rate is the highest (*i.e.*, least stringent).[374] This aspect of our methodology not only ensures that the nationwide CO_2 emission performance rates are achievable by affected EGUs in all three interconnections but also provides additional headroom within the BSER for affected EGUs in the two interconnections that did not set the CO_2 emission performance rates ultimately used. Additional headroom within the BSER is available through the use of emissions trading approaches, because the final rule does not limit the use of these mechanisms to sources within the same interconnections. In fact, in response to proposals that emerged from the comment record and direct engagement with states and stakeholders reflecting their strong interest in pursuing multi-state approaches, the guidelines include mechanisms for implementing standards of performance that incorporate interstate trading, as discussed in section VIII. (In addition, as further discussed below, the rule

[374] Specifically, the annual CO_2 emission performance rates applicable to steam EGUs in all three interconnections are the annual emission rates achievable by that subcategory in the Eastern Interconnection through application of the building blocks. Similarly, the annual CO_2 emission performance rates applicable to stationary combustion turbines in all three interconnections are the annual emission rates achievable by that subcategory in the Texas Interconnection for years from 2022 to 2026, and in the Eastern Interconnection for years from 2027 to 2030, through application of the building blocks. Additional information is provided in the CO_2 Emission Performance Rate and State Goal Computation TSD in the docket.

also permits section 111(d) plans to allow the use of non-BSER measures for compliance in certain circumstances, increasing both compliance flexibility and the assurance that the emission limitations reflecting application of the BSER are achievable.)

Further, the sets of measures in each of these individual building blocks, in the stringency assigned in this rule, meet the criteria for the BSER. That is, they each achieve the appropriate level of reductions, are of reasonable cost, do not impose energy penalties on the affected EGUs and do not result in non-air quality pollutants, and have acceptable cost and energy implications on a source-by-source basis and for the energy sector as a whole. In addition, as explained below, each is adequately demonstrated. Importantly, past industry practice and current trends strongly support each of the building blocks, as do federal and state pollution control programs that require or result in similar measures.

For example, all of the measures in building blocks 2 and 3 have been implemented for decades, initially for reasons unrelated to pollution control, then in recent years in order to control non-GHG air pollutants, and more recently, for purposes of CO_2-emission control by states and companies. Moreover, Congress itself recognized in enacting the acid rain provisions of CAA Title IV that RE measures reduce CO_2 from affected EGUs. In addition, the EPA has relied on the measures in building blocks 2 and 3 in other rules.

It should also be noted that building blocks 2 and 3 also meet the criteria for the BSER in combination with one another and with building block 1, as described below.

e. *Actions that individual affected EGUs could take to apply or implement the building blocks.* We now turn to a summary of measures or actions that individual EGUs could take to apply or implement the building blocks and that are therefore, in that sense, part of the BSER.

(1) *Improvement in CO_2 emission rate at the unit.*

An affected EGU may take steps to improve its CO_2 emission rate as discussed above for the source category as a whole. As discussed in section V.C., the record makes clear that coal-fired steam EGUs can make, and have made, heat rate improvements to a greater or lesser degree, resulting in reductions in CO_2 emissions. The resulting improvement in an EGU's CO_2 emission rate would help the EGU achieve an emission limit imposed in the form of an emission rate. If the EGU's emission limit is imposed in the form of a mass standard, the heat rate improvement would also lower the EGU's mass emissions provided that the EGU held the amount of its generation constant or increased its generation by a smaller percentage than the efficiency improvement. Under a mass-based standard that incorporates emission trading, an EGU that improves its heat rate would need fewer emission allowances for each MWh of generation whatever level of generation it chose to produce.

(2) *Actions to implement measures in building blocks 2 and 3.*

Viewing the BSER from the perspective of an individual EGU, there are several ways that affected EGUs can access the measures in building blocks 2 and 3, thanks to the integrated nature of the electricity system, coupled with the system's high degree of planning and reliability mechanisms. The affected EGUs can: (a) Invest in lower- or zero-emitting generation, which will lead to reductions in higher-emitting generation at other units in the integrated system; (b) reduce their generation, which in the presence of emission reduction requirements applicable to the source category as a whole will have the effect of increasing demand for, and thereby incentivize investment in, the measures in the building blocks elsewhere in the integrated system; or (c) both invest in the measures in the building blocks and reduce their own generation, effectively replacing their generation with cleaner generation. The availability of these options is further enhanced where the individual EGU is operating under a standard of performance that incorporates emissions trading.

(a) *Investment in measures in building blocks 2 and 3.*

An affected EGU may take the following actions to invest in the measures in building blocks 2 and 3. For building block 2, the owner/operator of a steam EGU may increase generation at an existing NGCC unit it already owns, or one that it purchases or invests in. In addition, the owner/operator may, through a bilateral transaction with an existing NGCC unit, pay the unit to increase generation, and acquire the CO_2-reducing effects of that increased generation in the form of a credit, as discussed below.

Similarly, for building block 3, an owner/operator of an affected EGU may build, or purchase an ownership interest in, new RE generating capacity and acquire the CO_2-reducing effects of that increased generation. Alternatively, an owner/operator may, through bilateral transactions, purchase the CO_2-reducing effects of that increased generation from renewable generation providers, again, in the form of a credit.

In 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.[375]

When combined with reduced generation, either at the affected EGU or elsewhere in the interconnected system, the types of actions listed above would be fully equivalent to building blocks 2 and 3 when viewed from the perspective of the overall source category. Thus, a source could achieve a standard of performance identical to the applicable CO_2 emission performance rate in the EPA emission guidelines, through implementation of the actions described above for building blocks 2 and 3, along with the actions described further above for building block 1.

The EPA anticipates that in instances where section 111(d) plans provide for the use of instruments such as ERCs as a mechanism to facilitate use of these measures, organized markets will develop so that owner/operators of affected EGUs that have invested in measures eligible for the issuance of ERCs will be able to sell those credits and other affected EGUs will

[375] Criteria for issuance of valid ERCs and for tracking credits after issuance are discussed in section VIII below.

be able to purchase them. Such markets have developed for other instruments used for emissions trading purposes. For example, liquid markets for SO_2 allowances developed rapidly following the implementation of Title IV of the 1990 Clean Air Act Amendments establishing the Acid Rain Program. Members of Congress and industry had expressed concern during the legislative debate that the lack of a liquid SO_2 allowance market would create challenges for affected sources that needed to acquire allowances to meet their compliance obligations. Congress added statutory provisions to ensure that, should a market not develop, sources could purchase needed allowances directly from the EPA. In fact, these provisions went unused because a liquid market for allowances did develop very quickly. Sources engaged in allowance transactions directly with other sources as they sought to lower compliance costs. Market intermediaries offered services to sources to match allowance buyers and sellers and helped sources understand their compliance options. Trade associations worked with members to develop standardized contracts and other tools to facilitate allowance transactions, thereby reducing transaction costs. Similar developments have occurred in state-level renewable portfolio standard programs.[376]

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[376] The emergence of markets under the Acid Rain Program and other environmental programs where trading has been permitted, as well as state and industry support for the development of markets under states' section 111(d) plans, is discussed in a recent report by the Advanced Energy Economy Institute. AEE Institute, *Markets Drive Innovation—Why History Shows that the Clean Power Plan Will Stimulate a Robust Industry Response* (July 2015), available at

If states choose to allow through their section 111(d) plans mechanisms or standards of performance involving instruments such as ERCs, the EPA believes that there would be an ample supply of such credits, for several reasons. First, as discussed in sections V.D. and V.E., the EPA has established the stringencies for building blocks 2 and 3 at levels that are reasonable and not at the maximum achievable levels, providing headroom for investment in the measures in these building blocks beyond the amounts reflected in the CO_2 emission performance rates reflecting application of the BSER. In addition, if emission limits are set at the CO_2 emission performance rates, affected EGUs in two of the three interconnections on average do not need to implement the building blocks to their full available extent in order to achieve their emission limits (because the performance rates for each source category are the emission rates achievable by that source subcategory through application of the building blocks in the interconnection where that achievable emission rate is the highest), providing further opportunities in those interconnections to generate surplus emission reductions that could be used as the basis for issuance of ERCs. Further, to the extent that section 111(d) plans take advantage of the latitude the final guidelines provide for states to set standards of performance incorporating emissions trading on an interstate basis among affected EGUs in different interconnections, all sources can take advantage of the headroom available in other interconnections. As a result, significant amounts of existing NGCC capacity

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https://www.aee.net/aeei/initiatives/epa-111d.html#epa-reports-and-white-papers.

and potential for RE remain available to serve as the basis for issuance of ERCs for all affected EGUs in both source subcategories to rely on to achieve their emission limits. Because we recognize the ready availability to states of standards of performance that incorporate emissions trading—and because such standards can easily encompass interstate trading—this rule includes by express design a variety of options that states and utilities can select to pursue interstate compliance regimes that mirror the interconnected operation of the electricity system. As a result, the EPA believes that it is reasonable to anticipate that a virtually nationwide emissions trading market for compliance will emerge, and that ERCs will be effectively available to any affected EGU wherever located, as long as its state plan authorizes emissions trading among affected EGUs.[377]

[377] There is a theoretical possibility—which we view as extremely unlikely—that the affected EGUs in a given state or group of states that has chosen to pursue a technology-specific rate-based approach could have insufficient access to ERCs because of the choices of certain other states to pursue mass-based or blended-rate approaches. We view this as very unlikely in part because of the conservative assumptions used in calculating the emission reductions available through the building blocks and the broad availability of non-BSER emission reduction opportunities, such as energy efficiency, that will generate ERCs. If such a situation arises, and the state or states implementing the technology-specific rates does not have, within the state or states, sufficient ERC-generation potential to match their compliance requirements, the EPA will work with the state or states to ensure that there is a mechanism that the state or states can include in their state plans to allow the affected EGUs in the state or states to generate additional ERCs where the state or states can demonstrate that the ERCs do not represent double-counting under other state programs. One potential mechanism

It should also be noted that although in a state that sets emission limits in a rate-based form the measures in building blocks 2 and 3 can be taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit, in a state that sets emission limits in a mass-based form these measures are not taken into account directly in computations to determine whether an individual affected EGU has achieved its emission limit. However, by reducing generation and therefore CO_2 emissions from the group of affected EGUs within a region, in a state with mass-based limits implementation of these measures facilitates the

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would be to assume for purposes of demonstrating compliance with their standards of performance that the generation replacing any reductions in generation at those affected EGUs that was not paired with verified ERCs came from existing NGCC units in other states from which ERCs were not accessible. In other words, any reductions in fossil steam generation from 2012 levels in a state or states that was implementing technology-specific rates that could not be matched by increases in NGCC generation or by ERCs from zero-emitting sources, and for which it could be demonstrated that no further ERCs can be procured, could generate building block 2 ERCs as if that level of displaced generation were NGCC generation. A demonstration that no further ERCs are procurable would have to include demonstrations that the capacity factor of all NGCC generation in the state or states was expected to be greater than 75 percent and that further deployment of RE would go beyond the amounts found available in the BSER. States could distribute these additional ERCs to ensure compliance by affected EGUs. Before such ERCs could be created by a state or states, a framework would have to be submitted to the EPA for approval including documentation of the levels of fossil steam and NGCC generation in the state or states, a demonstration that no further ERCs are accessible, and the total amount of building block 2 ERCs to be created.

ability of the individual EGUs within the region to achieve their limits by choosing to reduce their own generation and emissions.

(b) *Reduced generation.*

In addition, the owner/operator of an affected EGU may help itself meet its emission limit by reducing its generation. If the owner/operator reduces generation and therefore the amount of its CO_2 emissions, then, if the affected EGU is subject to an emission rate limit, the owner/operator will need to implement fewer of the building block measures, *e.g.*, buy fewer ERCs, to achieve its emission rate; and if the affected EGU is subject to a mass emission limit, the owner/operator will need fewer mass allowances. As discussed below, at the levels that the EPA has selected for the BSER, reduced generation at higher-emitting EGUs does not decrease the amount of electricity available to the system and end users because lower-emitting (or zero-emitting) generation will be available from other sources.

An owner/operator may take actions to ensure that it reduces its generation. For example, it may accept a permit restriction on the amount of hours that it generates. In addition or alternatively, it may represent the cost of additional emission credits or allowances that would be required due to incremental generation as an additional variable cost that increases the total variable cost considered when dispatch decisions are made for the unit.

Because of the integrated nature of the electricity system, combined with the system's high degree of planning and reliability safeguards, as well as the long planning horizon afforded by this rule, individual affected EGUs can implement the building blocks by reducing generation to achieve their emission performance standards.[378] Individual affected steam EGUs can reduce their generation in the amounts of building blocks 2 and 3, while individual affected NGCC units can reduce their generation in the amount of building block 3. With emission limits for the source category as a whole in place, the resulting reduction in supply of higher-emitting generation will incentivize additional utilization of existing NGCC capacity, the resulting reduction in overall fossil fuel-fired generation will incentivize investment in additional RE generating capacity, and the integrated system's response to these incentives will ensure that there will be sufficient electricity generated to continue to meet the demand for electricity services.

(c) *Emissions trading.*

As described above, viewed from the perspective of the source category as a whole, it is reasonable for our analysis of the BSER to include an element of source-category-wide multi-unit compliance which could be implemented via a state-set standard of performance incorporating emissions trading, under which EGUs could engage in trading of rate-based emission credits or mass-based emission allowances. By the same token, viewed from the perspective of an individual EGU, consideration of the ready availability to states of the opportunity to establish standards of performance that incorporate emissions trading is

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[378] For purposes of this discussion, we assume that coal-fired steam generators also implement building block 1 measures so that they will implement the full set of measures needed to achieve their emission limit.

integral to our analysis. Accordingly, our assessment of the actions available to individual EGUs for achieving standards of performance reflecting the BSER includes the purchase of rate-based emission credits or mass-based emission allowances, because one of the things an affected EGU can do to achieve its emission limit is to buy a credit or an allowance from another affected EGU that has over-complied. The use of purchased credits or allowances would have to be authorized, of course, in the purchasing EGUs' states' section 111(d) plans and would have to meet conditions set out for such approaches in section VIII below. The role of emissions trading in the BSER analysis is discussed further in section V.A.2.f. below.

f. *The role of emissions trading*. In making its BSER determination here, the EPA examined a number of technologies and emission reduction measures that result in lower levels of CO_2 emissions and evaluated each one on the basis of the several criteria on which the EPA relies in determining the BSER. In contrast to section 111(b), however, section 111(d)(1) obliges the states, not the EPA, to set standards of performance for the affected EGUs in order to implement the BSER. Accordingly, with respect to each measure or control strategy under consideration, the EPA also evaluated whether or not the states could establish standards of performance for affected EGUs that would allow those sources to adopt the measure in question. In this case, the EPA identified a host of factors that persuaded us that states could—and, in fact, may be expected to—establish standards of performance that incorporate emissions trading.[379] These wide-ranging factors include (i) the global nature of the air pollutant in question—*i.e.*, CO_2; (ii) the transactional nature of the industry; (iii) the interconnected functioning of the industry and the coordination of generation resources at the level of the regional grid; (iv) the extensive experience that states—and EGUs—already have with emissions trading; and (v) material in the record demonstrating strong interest on the part of many states and affected EGUs in using emissions trading to help meet their obligations.[380]

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[379] As an alternative to authorizing trading that would still provide a degree of multi-unit flexibility, a state could choose in its state plan to give an owner of multiple affected EGUs flexibility regarding how the owner distributes any credits or allowances it acquires among its affected EGUs.

[380] Numerous states submitted comments urging the EPA to allow states to develop trading programs, as suggested in the proposal, including interstate trading programs. They include, for example, Alabama (EPA should develop and issue guidelines that allow options for multi-state plans and interstate credit trading programs, comment 23584), California (EPA should provide flexibility for allowance trading programs to be integrated into state plans, comment 23433), Hawaii (supports use of emission credit trading with other entities to achieve compliance, comment 23121), Massachusetts (EPA should explore possibility of hosting a third-party emissions trading bank that can allow states interested in allowance trading to plug and play in to a wider, more cost-effective market, comment 31910), Michigan (supports emissions trading programs, comment 23987), Minnesota (develop model trading rule that states could incorporate by reference as part of plan and automatically be included in multi-state mass trading program, comment 23987), North Carolina (EPA should examine a system of banking and trading for energy efficiency, comment 23542), Oregon (EPA should expand the explicit options for multi-state plans beyond cap-and-trade, comment 20678), Washington

(supporting trading, comment 22764), Wisconsin (requesting EPA to develop a national trading program, Post-111(d) Proposal Questions to EPA WI Questions for 7/16 Hub call).

In addition, several groups of states supported trading programs: Georgetown Climate Center (a group of state environmental agency leaders, energy agency leaders, and public utility commissioners from California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington) ("We believe states should have maximum flexibility to determine what kinds of collaborations might work for them. These could include submission of joint plans, standardized approaches to trading renewable or energy efficiency credits. . . . We also encourage EPA to help facilitate such interstate agreements or multi-state collaborations by working with states to either identify or provide a platform or framework that states may elect to use for the tracking and trading of avoided generation or emissions credits due to interstate efficiency or renewable energy." comment 23597, at 39–40); RGGI (including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont) ("[E]very serious proposal to reduce carbon emissions from EGUs, from proposed US legislation to programs in place in California and Europe, has identified allowance trading as the best approach." Comment 22395 at 7–8); Western States Center for New Energy Economy (including Arizona, California, Colorado, Idaho, Montana, Nevada, Oregon, South Dakota, Utah, Washington) ("Some degree of RE and EE credit trading among states may support compliance, even in the absence of a comprehensive regional plan. Therefore, EPA should support approaches which allow states flexibility to allocate credit for these zero-carbon resources, along with approaches which allow states to reach agreements on the allocation of carbon liabilities. This includes ensuring that existing tracking mechanisms for renewable energy in the West, such as the Western Renewable Energy Generation Information System (WREGIS), are compatible with the final proposal." Comment 21787 at 5); Midcontinent States Environmental and Energy Regulators (including Arkansas, Illinois, Michigan, Minnesota Missouri, Wisconsin) (EPA should also provide states with

The states' and EGUs' interest in emissions trading is rooted in the well-recognized benefits that trading provides. The experience of multiple trading programs over many years has shown that some units can achieve emission reductions at lower cost than others, and a system that allows for those lower-cost reductions to be maximized is more cost-effective overall to the industry and to society. Trading provides an affected EGU other options besides direct implementation of emission reduction measures in its own facility or an affiliated facility when lower-cost emission reduction opportunities exist elsewhere. Specifically, the affected EGU can cross-invest, that is,

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optional . . . systems (or system) for tracking emissions, allowances, reduction credits, and/or generation attributes that states may choose to use in their 111(d) plans," comment 22535 at 3).

In addition, trading programs were supported by, among others, a group of Attorneys General from 11 states and the District of Columbia. Comment 25433 (Attorneys General from New York, California, Connecticut, Maine, Maryland, Massachusetts, New Mexico, Oregon, Rhode Island, Vermont, Washington, District of Columbia, and New York City Corporation Counsel).

Numerous industry commenters also supported trading, including Alliant Energy Corporate Services, Inc. (comment 22934), Calpine (comment 23167), DTE Energy (comment 24061), Exelon (comment 23428 and 23155), Michigan Municipal Electric Association (MMEA) (comment 23297), National Climate Coalition (comment 22910), Pacific Gas and Electric Company (comment 23198), Western Power Trading Forum (WPTF) (comment 22860). Environmental advocates also supported trading, including Clean Air Task Force (comment 22612), Environmental Defense Fund (comment 23140), Institute for Policy Integrity, New York University School of Law (comment 23418).

invest in actions at facilities owned by others, in exchange for rate-based emission credits or mass-based emission allowances. Through cross-investment, trading allows each affected EGU to access the control measures that other affected EGUs decide to implement, which in this case include all the building blocks as well as other measures.

Accordingly, our analysis of the measures under consideration in our BSER determination reflected the well-founded conclusion that it is reasonable for states to incorporate emissions trading in the standards of performance they establish for affected EGUs and that many, if not all, would do so.[381]

Whether viewed from the perspective of an individual EGU or the source category as a whole, emissions trading is thus an integral part of our BSER analysis. Again, we concluded that this is reasonable given the global nature of the pollutant, the transactional and interconnected nature of this industry, and the long history and numerous examples demonstrating that, in this sector, trading is integral to how regulators have established, and sources have complied with, environmental and similar obligations (such as RE standards) when it was appropriate to do so given the program objective. The reasonableness is further demonstrated by the numerous comments (some of which are noted above) from industry, states, and other stakeholders in this rulemaking that

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[381] As discussed in the Legal Memorandum, the EPA has promulgated other rulemakings, including the transport rulemakings—the NO_X SIP Call and CAIR, which required states to submit SIPs, and CSAPR, which allows SIPs—on the premise of interstate emission trading.

supported allowing states to adopt trading programs to comply with section 111(d) and encouraged EPA to facilitate trading across state lines through the use of trading-ready state plans. The EPA's reliance on trading in its BSER determination does not mean, however, that states are required to establish trading programs (just as states are not required to implement the building blocks that comprise BSER). Nor does it mean that trading is the only transactional approach that we could have considered in setting the BSER or that states could use to effectuate the building blocks were they to decide that they did not want to take on the responsibility of running a trading program. Rather, it is simply a recognition of the nature of this industry and the long history of trading as an important regulatory tool in establishing regulatory regimes for this industry and its reasonable availability to states in establishing standards of performance.

As an initial matter, trading is permissible for these emission guidelines because CO_2 is a global pollutant; the location of its emission does not affect the location of the environmental harm it causes. For CO_2, it is the total amount of emissions from the source category that matters, not the specific emissions from any one EGU. The fact that trading allows sources to shift emissions from one location to another does not impede achievement of the environmental goal of reducing CO_2 pollution. In its character as a pollutant whose impacts extend beyond local areas, CO_2 pollution resembles to some extent the regional SO_2 pollution that Congress chose to address with the emissions trading program enacted in Title IV of the 1990 CAA Amendments. The argument in support of trading approaches is even stronger for CO_2 pollution, whose adverse effects are global rather than merely regional like the SO_2 emissions contributing to acid precipitation.

Further, as discussed elsewhere in the preamble, the utility power sector—and the affected EGUs and other generation assets that it encompasses—has a long history of working on a coordinated basis to meet operating and environmental objectives, necessitated and facilitated by the unique interconnectedness and interdependence of the sector. That history includes joint dispatch for economic and reliability purposes, both within large utility systems and in multi-utility power pools that have evolved into RTOs; joint power plant ownership arrangements; and long-term and short-term bilateral power purchase arrangements. More recently, the sector's history also includes emissions trading programs designed by Congress, the EPA, and the states to address regional environmental problems and, most recently, climate change. Examples of such programs are noted below.

Essentially, trading does nothing more than commoditize compliance, with the following two important results emerging from that: It reduces the overall costs of controls and spreads those costs among the entire category of regulated entities while providing a greater range of options for sources that may not want to make on-site investments for controlling their emissions and may prefer to make the same investment, via the purchase of the tradable compliance instrument, at another generating source. Building blocks 2 and 3 entail affected EGUs investing in increased generation from existing NGCC units and RE. The affected EGUs could do so in any number of ways, including acquiring ownership interests in existing NGCC or RE facilities or entering into bilateral transactions with the owners of existing NGCC facilities or RE sources. As discussed elsewhere, it is reasonable to expect that these actions can develop into discrete, tradable commodities (*e.g.*, an ERC) and that liquid markets will develop, which would reduce transaction costs and allow an affected EGU to comply with its emission limits by purchasing discrete units in amounts tailored closely to its compliance needs. The existence of such tradable commodities also incentivizes over-compliance by affected EGUs, which can then sell their over-compliance in the form of ERCs or allowances to other affected EGUs. Moreover, as noted elsewhere, the opportunity to trade is consistent with the EPA's regional approach for the building blocks.

By the same token, the opportunity to trade incentivizes affected EGUs to over-comply with building block 1. Thus, the opportunity to trade supports the EPA's assumptions about what an average affected EGU can achieve with regards to heat rate improvement even if each and every affected EGU cannot achieve that level of improvement. In addition, trading incentivizes affected EGUs to consider low-cost, non-BSER methods to reduce emissions as well, and, as discussed below, there are numerous non-BSER methods, ranging from implementation of demand-side EE programs to natural gas co-firing.

Trading has become an important mechanism for achieving environmental goals in the electricity sector in part because trading allows environmental regulators to set an environmental goal while preserving the ability of the operators of the affected

EGUs to decide the best way to meet it taking account of the full range of considerations that govern their overall operations. For example, commenters were concerned that because of building block 2, the emission guidelines would require state environmental regulators to make dispatch decisions for the electricity markets, a role that state environmental regulators do not currently play. Although building block 2 entails substituting existing NGCC generation for steam generation, implementing the emission limits that are based in part on building block 2 through a trading program provides the individual affected EGUs with a great deal of control over their own generation while the industry as a whole achieves the environmental goals. For example, individual steam generators have the option of maintaining their generation as long as they acquire additional ERCs. Moreover, trading provides a way for states to set standards of performance that realize the required emissions reduction without requiring any form of "environmental dispatch" because, as many existing trading programs have shown, monetization of the environmental constraint is consistent with a least-cost dispatch system. Trading also supports the EPA's approach to the "remaining useful life" provision in section 111(d)(1) because with trading, an affected EGU with a limited remaining useful life can avoid the need to implement long-term emission reduction measures and can instead purchase ERCs or other tradable instruments, such as mass-based allowances, thereby allowing the state to meet the requirements of this rule.

The EPA's job in issuing these emission guidelines is to determine the BSER that has been adequately demonstrated and to set emission limitations that are achievable through the application of the BSER and implementable through standards of performance established by the states. The three building blocks are the EPA's determination of what technology is adequately demonstrated. We also consider trading an integral part of the BSER analysis because, in addition to being available to states for incorporation in the standards of performance they set for affected EGUs, trading has been adequately demonstrated for this industry in circumstances where systemic rather than unit-level reductions are central. Congress, the EPA, and state regulators have established successful environmental programs for this industry that allow trading of environmental (or similar) attributes, and trading has been widely used by the industry to comply with these programs. Examples include the CAA Title IV Acid Rain Program, the NO_X SIP Call (currently referred to as the NO_X Budget Trading Program), the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR),[382] the Regional Haze trading programs, the Clean Air

[382] For example, in CSAPR, which covered the states in the eastern half of the U.S., the EPA assumed the existence of trading across those states in the rule's cost estimates contained in the RIA. "Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States" 32 (June 2011), *http://www.epa.gov/airtransport/CSAPR/pdfs/FinalRIA.pdf*. In addition, the rule is being implemented either through federal implementation plans (FIPs) that authorize interstate emission trading or SIPs that authorize interstate emissions trading.

Mercury Rule,[383] RGGI, the trading program established by California AB32, and the South Coast Air Quality Management District RECLAIM program. We describe these programs in section II.E. of this preamble. In addition, we note in the Legal Memorandum accompanying this preamble that Congress, in enacting the Title IV acid rain trading program, and the EPA, in promulgating the regulatory trading programs listed, recognized both the suitability of trading for the EGU industry and the benefits of trading in reducing costs, spreading costs to affected EGUs throughout the sector, and facilitating the ability of affected EGUs to comply with their emission limits. In addition, as we discuss in section V.E. of this preamble, many states have adopted RE standards that promote RE through the trading of renewable energy certificates (RECs).

Based on this history, it is reasonable for the EPA to determine that states can establish standards of performance that incorporate trading and, as a result, for the purpose of making a BSER determination here to evaluate prospective emission control measures in light of the availability of trading. Trading is a regulatory mechanism that works well for this industry. The environmental attributes in the preceding programs (representing emissions of air pollutants) are identical to or similar in nature to the

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[383] Although the CAMR trading program never took effect because the rule was vacated on other grounds, it consisted of a nationwide trading program that the EPA adopted under CAA section 111(d). Some states declined to allow their sources to participate in the trading program on the grounds that nationwide trading was not appropriate for the air pollutant at issue, mercury, a HAP that caused adverse local impacts.

environmental attribute here (CO_2 emissions). The markets for RECs show that robust markets for RE, in particular, already exist.

Given the benefits of trading and the background of multi-unit coordination grounded in the nature of the utility power sector, it is natural for sources and states to look for opportunities to apply similar coordination to a regional problem such as reduction of CO_2 emissions from the sector. As noted earlier, the EPA heard this interest expressed during the outreach process for this rulemaking and saw it reflected in comments on the proposal. Emissions trading was prominent in these expressions of interest; while the proposal allowed trading and encouraged the development of multi-state plans which would allow the benefits of trading to extend over larger regions, we heard that interest was even greater in "trading-ready" plans that would use trading mechanisms and market-based coordination, rather than state-to-state coordination, as the primary means of facilitating multi-unit approaches to compliance. The general industry and state preference for multi-unit compliance approaches makes great sense in the context of the industry and this pollutant, as does the specific preference for trading-ready section 111(d) plans, and we have made efforts in the final rule to accommodate trading-ready plans as described in section VIII.

g. *Measures that reduce CO_2 emissions or CO_2 emission rates but are not included in the BSER.* There are numerous other measures that are available to at least some affected EGUs to help assure that they can achieve their emission limits, even though the EPA is not identifying these measures as part of the

BSER. These measures include demand-side EE implementable by affected EGUs; new or uprated nuclear generation; renewable measures other than those that are part of building block 3, including distributed generation solar power and off-shore wind; combined heat and power and waste heat power; and transmission and distribution improvements. In addition, a state may implement measures that yield emission reductions for use in reducing the obligations on affected EGUs, such as demand-side EE measures not implementable by affected EGUs, including appliance standards, building codes, and drinking water or wastewater system efficiency measures. The availability of these measures further assures that the appropriate level of emission reductions can be achieved and that affected EGUs will be able to achieve their emission limits.

h. *Ability of EGUs to implement the BSER.* The EPA's analysis, based in part on observed decades-long behavior of EGUs, shows that all types and sizes of affected EGUs in all locations are able to undertake the actions described as the BSER, including investor-owned utilities, merchant generators, rural cooperatives, municipally-owned utilities, and federal utilities. Some may need to focus more on certain measures; for example, an owner of a small generation portfolio consisting of a single coal-fired steam EGU may need to rely more on cross-investment approaches, possibly including the purchase of emission credits or allowances, because of a lack of sufficient scale to diversify its own portfolio to include NGCC capacity and RE generating capacity in addition to coal-fired capacity. As a legal matter, it is not necessary that each affected EGU be able to implement the BSER, but in any event, in this rule, all affected EGUs can do so. Since states can reasonably be expected to establish standards of performance incorporating emissions trading, affected EGUs may rely on emissions trading approaches authorized under their states' section 111(d) plans to, in effect, invest in building block measures that are physically implemented at other locations. As discussed above, the EPA's quantification of the CO_2 emission performance rates in a manner that provides headroom within the BSER also contributes to the ability of all affected EGUs to implement the BSER and achieve emissions limitations consistent with those performance rates.

i. *Subcategorization*. As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines. As we discuss below, this approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare and then to regulate new sources within each such source category, and which grant the EPA discretion whether to subcategorize the sources for purposes of determining the BSER.

As discussed below, each affected EGU can achieve the performance rate by implementing the BSER, specifically, by taking a range of actions—some of which depend on features of the section 111(d) plan chosen by the state, such as the choice of rate-based or mass-based standards of performance and the choice of whether and how to permit emissions trading—including investment in the building blocks, replaced or reduced generation, and purchase of emission credits or allowances. Further, in the case of a rate-based state plan, several other compliance options not included in the BSER for this rule are also available to all affected EGUs, including investment in demand-side EE measures. Such compliance options may also indirectly help affected EGUs achieve compliance under a mass-based plan.

Our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates and can do so at a reasonable cost using the approaches we have identified as the BSER as well as other available measures.

Of course, a state retains great flexibility in assigning standards of performance to its affected

EGUs and can impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below.

3. Changes From Proposal

For the BSER determined in this final rule, based on consideration of comments responding to a broad array of topics considered in the proposal, the EPA has adopted certain modifications to the proposed BSER. In this subsection we describe the most important modifications, including some that relate to individual building blocks and some that are more general. Additional modifications that relate to individual building blocks are discussed in the respective sections for those building blocks below (sections V.C. through V.E.).

We note that taken together, the modifications yield emission reductions requirements that commence more gradually than the proposed goals but are projected to produce greater overall annual emission reductions by 2030. [384] We also note that the modifications lead to requirements that are more uniform across states than the proposed state goals (consistent with the direction of certain alternatives on which we sought comment in the proposal), with the final requirements generally becoming more

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[384] For the proposed rule, the EPA projected total CO_2 emission reductions from 2005 levels of 29% in 2025 and 30% in 2030. For the final rule, the EPA projects total CO_2 emissions reductions from 2005 levels of 28% in 2025 and 32% in 2030. See Regulatory Impact Analysis for the CPP Proposed Rule, Table 3-6, and Regulatory Impact Analysis for the CPP Final Rule, Table 3-6, available in the docket.

stringent (compared to the proposal) in states with the highest 2012 CO_2 emission rates and less stringent in states with lower 2012 CO_2 emission rates.

a. *Interpretations of CAA section 111*. In the June 2014 proposal, the EPA proposed interpretations of section 111(a)(1) and (d), and applied these interpretations to existing fossil fuel-fired EGUs.[385] Informed by comments, the EPA has clarified some of these interpretations, and has developed a more refined understanding of how some of these interpretations should be applied. The clarified and more refined interpretations replace the proposed interpretations.

Two of these points merit mention here. First, the EPA is clarifying in this rule that the interpretation of "system of emission reduction" does not include emission reduction measures that the states have authority to mandate without the affected EGUs being able to implement the measures themselves (*e.g.*, appliance standards or building codes). In the final rule, we have clarified that the components of the BSER must be implementable by the affected EGUs, not just by the states, and we show that all the components of the BSER have been demonstrated to be achievable on that basis without reliance on actions that can be accomplished only through government mandates. Further discussion of these points can be found throughout this section on the BSER and the following sections on the individual building blocks.

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[385] The June 2014 proposal in part referenced proposed interpretations of section 111(a)(1) that the EPA explained in the January 2014 proposal to address CO_2 emissions from new fossil fuel-fired EGUs under section 111(b).

Second, the EPA has adopted a combined interpretation of sections 111(a)(1) and 111(d) that, compared to the proposal, better reflects the historical interpretations of section 111(a)(1), which have generally supported emissions standards that are nationally uniform for sources incorporating a given technology, and gives less weight to the state-focused character of section 111(d), which calls for emissions standards to be implemented through the development of individual state plans. The proposed state goals were heavily (although not entirely) dependent on the emission reduction opportunities available to the EGUs in each individual state, and because the relative magnitudes of these opportunities varied by state, states with similar EGU fleet compositions could have faced state goals of different stringencies, potentially making it difficult for multiple states to set the same standards of performance for affected EGUs using the same technologies (assuming the states were interested in setting standards of performance for their various affected EGUs in such a manner). Some commenters viewed this potential result as inconsistent with section 111(a)(1), inequitable, or both. In response, we took further comment on these potential disparities in the October 30, 2014 NODA. In this final rule, we are obviating those concerns by assessing the emission reduction opportunities at an appropriate regional scale, consistent with alternatives on which we sought comment, and using this regional information to reformulate the proposed emissions standards as nationally uniform emissions standards for the emission guidelines.[386] National uniformity is consistent with prior section 111 rulemaking and advances a number of other goals central to this rulemaking. The methodological refinements related to regional assessment of emission reduction opportunities and the use of uniform emissions standards by technology subcategory are further discussed below.

b. *Approach to quantification of emission reductions from increased RE generation*. In the June 2014 proposal, the EPA described two possible approaches for quantifying the amount of emission reductions achievable from affected EGUs through the use of RE generation. The proposed approach used information on state RPS aggregated at a regional level along with historical RE generation data to project the amount of RE generation used in quantifying the emission reductions achievable through the BSER. The alternative approach used information on the technical and market potential for development of renewable resources in each state to project the RE-related emission reductions. In the October 30, 2014 NODA, we sought comment on an additional approach of aggregating the state-level information to a regional level, as suggested by some commenters. In this final rule we are adopting a combination of these approaches that uses historical RE generating capacity deployment data aggregated to a regional level, supported and confirmed by

[386] Of course, a source in one state may face different requirements than similar sources in other states, depending on whether the state adopts the state measures approach or, if it adopts the emission standards approach, whether it imposes a mass limit or an emission rate and, if the latter, at what level.

projections of market potential developed through a techno-economic approach.

In the June 2014 proposal, RE generation was also quantified as generation from total—that is, existing and new—RE generating capacity, a formulation that was consistent with the formulation of most RPS, which are typically framed in terms of total rather than incremental generation. In response to the EPA's request for comment on this approach, commenters observed that the approach was inconsistent with the approach taken for other building blocks, and that generation from RE generating capacity that already existed as of 2012 should not be treated as reducing emissions of affected EGUs from 2012 levels. As just noted, we are not using the RPS-based methodology in the final rule, and we agree with comments that quantification of RE generation on an incremental basis is both more consistent with the treatment of other building blocks and more consistent with the general principle that the BSER should comprise incremental measures that will reduce emissions below existing levels, not measures that are already in place, even if those in-place measures help current emission levels be lower than would be the case without the measures. The final rule therefore defines the RE component of the BSER in terms of incremental rather than total RE generation.[387] Further details regarding the final rule's

[387] Generation from existing RE capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

quantification of RE generation are provided in section V.E. below.

c. *Exclusion from the BSER of emission reductions from use of under-construction or preserved nuclear capacity*. In the June 2014 proposal, the EPA included in building block 3 provisions reflecting the ability for nuclear generation to replace fossil generation and thereby reduce CO_2 emissions at affected EGUs. We proposed to include in building block 3 the potential generation from five under-construction nuclear generating units whose construction had commenced prior to the issuance of the proposal. In addition, to address the potential that some currently operating nuclear facilities may shut down prior to 2030, the proposal incorporated into the BSER for each state with nuclear capacity a projected 5.8 percent reduction in nuclear generation, based on an estimate of potential nationwide loss of nuclear generation from existing units. We sought comment on all aspects of these proposed approaches. While we recognize the important role nuclear power plants have to play in providing carbon-free generation in an all-of-the-above energy system, for this final rule, the BSER does not include either of the components related to nuclear generation.

The EPA received numerous comments on the proposed BSER components related to nuclear power. With respect to generation from under-construction nuclear units, some commenters expressed strong opposition to the inclusion of this generation in the BSER and the setting of state goals, stating that inclusion would result in very stringent state goals for the states where the units are being built and that the inclusion of the generation in the goals is premature because the units' actual completion dates could be delayed. Commenters also stated that inclusion of the under-construction nuclear generation in the BSER would be inequitable because states where the same heavy investment in zero-CO_2 generation was not being made would have relatively less stringent goals.

With respect to generation from existing nuclear units, some commenters stated that our method of accounting for potential unit shutdowns was flawed, observing that even if the prediction of a 5.8 percent nationwide loss of nuclear generation were accurate, the actual shutdowns would occur in a handful of states, resulting in much larger losses of generation in those particular states.

Upon consideration of comments and the accompanying data, the EPA has determined that the BSER should not include either of the components related to nuclear generation from the proposal. With respect to nuclear units under construction, although we believe that other refinements to this final rule would address commenters' concerns that goals for the particular states where the units are located would be overly stringent either in absolute terms or relative to other states, we also acknowledge that, in comparison to RE generating technology, investments in new nuclear units tend to be individually much larger and to require longer lead times. Also, important recent trends evidenced in RE development, such as rapidly growing investment and rapidly decreasing costs, are not as clearly evidenced in nuclear generation. We view these factors as distinguishing the under-construction nuclear units from RE generating capacity, indicating that the new nuclear capacity is likely of higher cost and therefore less appropriate for inclusion in the BSER. Excluding the under-construction nuclear units from the BSER, but allowing emission reductions attributable to generation from the units to be used for compliance as discussed below and in section VIII, will recognize the CO_2 emission reduction benefits achievable through the significant ongoing commitment required to complete these major investments.

With respect to existing nuclear units, although again we believe that other refinements in the final rule would address the concern about disparate impacts on particular states, we acknowledge that we lack information on shutdown risk that would enable us to improve the estimated 5.8 percent factor for nuclear capacity at risk of retirement. Further, based in part on comments received on another aspect of the proposal—specifically, the proposed inclusion of existing RE generation in the goal-setting computations—we believe that it is inappropriate to base the BSER in part on the premise that the preservation of existing low- or zero-carbon generation, as opposed to the production of incremental, low- or zero-carbon generation, could reduce CO_2 emissions from current levels. Accordingly, we have determined not to reflect either of the nuclear elements in the final BSER.

Generation from under-construction or other new nuclear units and capacity uprates at existing nuclear units would still be able to help sources meet emission rate-based standards of performance through the creation and use of credits, as noted in section V.A.6.b. and section VIII.K.1.a.(8), and would help sources meet mass-based standards of performance through reduced utilization of fossil generating capacity leading to reduced CO_2 emissions at affected EGUs. However, consistent with the reasons just discussed for not reflecting preservation of existing nuclear capacity in the BSER—namely, that such preservation does not actually reduce existing levels of emissions from affected EGUs—the rule does not allow preservation of generation from existing or relicensed nuclear capacity to serve as the basis for creation of credits that individual affected EGUs could use for compliance, as further discussed in section VIII.K.1.a.(8).[388]

d. *Exclusion from the BSER of emission reductions from demand-side EE.* The June 2014 proposal included demand-side EE measures in building block 4 as part of the BSER. The EPA took comment on the attributes of each of the proposed building blocks, and building block 4 was a topic of considerable controversy among commenters. While many commenters recognized demand-side EE as an integral part of the electricity system, emphasized its cost-effectiveness as a means of reducing CO_2 emissions from the utility power sector, and strongly supported its inclusion in the BSER, other commenters expressed significant concerns.

As explained in section V.B.3.c.(8) below, our traditional interpretation and implementation of CAA section 111 has allowed regulated entities to produce

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[388] As with generation from existing RE capacity, generation from existing nuclear capacity will continue to make compliance with mass-based standards easier to achieve by making the overall amount of fossil fuel-fired generation that is required to meet the demand for energy services lower than it would otherwise be, thereby keeping CO_2 emissions lower than they would otherwise be.

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. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side EE as part of the final BSER determination.

It should be noted that commenters also took the position that the EPA should allow demand-side EE as a means of compliance with the requirements of this rule, and, as discussed in section V.A.6.b. and section VIII below, we agree.

e. *Consistent regionalized approach to quantification of emission reductions from all building blocks*. In the June 2014 proposal, the EPA treated each of the building blocks differently with respect to the regional scale on which the building block was applied for purposes of assessing the emission reductions achievable through use of that building block. Building block 1 was quantified at a national scale, identifying a single heat rate improvement opportunity applicable on average to all coal-fired steam EGUs. Building block 2 was quantified at the scale of each individual state, considering the amount of generation that could be shifted from steam EGUs to NGCC units within the state, although we solicited comment on considering generation shifts at a broader regional scale. The RE component of building block 3 was quantified at a regional scale using RPS information as a proxy for RE development potential, and the regional results were then applied to each state in the region using the state's baseline data; an alternative methodology on which we requested comment quantified the RE component using a techno-economic approach on a state-specific basis. In the October 2014 NODA, we requested comment on using a techno-economic approach to quantify RE generation potential at a regional scale and took broad comment on strategies for better aligning the BSER with the regionally interconnected electrical grid.[389] We also solicited comment on the appropriate regional boundaries or regional structure to facilitate this approach.

For the final rule, with the benefit of comments received in response to these proposals and alternatives, we have adopted a consistent regionalized approach to quantification of emission reductions achievable through all the building blocks. Under this approach, each of the building blocks is quantified and applied at the regional level, resulting in the computation for each region of a performance rate for steam EGUs and a performance rate for NGCC units. For each of the technology subcategories, we identify the most conservative—that is, the least stringent—of the three regional performance rates. We then apply these least stringent subcategory-specific performance rates to the baseline data for the EGU fleet in each state to establish state goals of consistent stringency across the country. (Note that the actual state goals vary among states to reflect the differences in generation mix among states in the baseline year.) Further description of the steps in this overall process is contained in the preamble sections addressing the individual building blocks (sections V.C., V.D., and V.E.), CO_2 emission performance rate

[389] 79 FR 64543, 64551–52.

computation (section VI), and state goal computation (section VII), as well as the GHG Mitigation Measures TSD for the CPP Final Rule and the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

Compared to the more state-focused quantification approach selected in the proposal, and as recognized in the NODA, a regionalized approach better reflects the interconnected system within which interdependent affected EGUs actually carry out planning and operations in order to meet electricity demand. We have already discussed the relevance of the interconnected system and the interdependent operations of EGUs as factors supporting consideration of building blocks 2 and 3 as elements of the BSER for this pollutant and this industry, and these same factors support quantifying the emission reductions achievable through building blocks 2 and 3 on a regionalized basis. Because it better reflects how the industry works, a regionalized approach also better represents the full scope of emission reduction opportunities available to individual affected EGUs through the normal transactional processes of the industry, which do not stop at state borders but rather extend throughout these interconnected regions. With respect to building block 1, which comprises types of emission reduction measures that in other rulemakings under CAA section 111 would typically be evaluated on a nationwide basis, for this rule, as discussed in section V.C. below, we are quantifying the emission reductions achievable through building block 1 on a regional basis in order to treat the building blocks consistently and to ensure that for each region the quantification of the BSER represents only as much potential emission reduction from building block 1 as our analysis of historical data indicates can be achieved on average by the affected EGUs in that region.

Characterizing and quantifying the measures included in the BSER on a regional basis rather than a state-limited basis is also appropriate because states can establish standards of performance that incorporate emissions trading, including trading between and among EGUs operating in different states, and thus provide EGUs the opportunity to trade. Emissions trading provides at least one mechanism by which owners of affected EGUs can access any of the building blocks at other locations. With emissions trading, an affected EGU whose access to heat rate improvement opportunities, incremental generation from existing NGCC units, or generation from new RE generating capacity is relatively favorable can overcomply with its own standard of performance and sell rate-based emission credits or mass-based emission allowances to other affected EGUs. Purchase of the credits or allowances by the other EGUs represents cross-investment in the emission reduction opportunities, and such cross-investment can be carried out on as wide a geographic scale as trading rules allow.

The regions we have determined to be appropriate for the regionalized approach in the final rule are the Eastern, Western, and Texas Interconnections.[390] In

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[390] The Texas Interconnection encompasses the portion of the Texas electricity system commonly known as ERCOT (for the Electric Reliability Council of Texas). The state of Texas has

determining that the appropriate regional level for quantification of the BSER was the level of the interconnection, the EPA considered several factors. First, consistent with our goal of aligning regulation with the reality of the interconnected electricity system, we considered the regional scale on which electricity is actually produced, physically coordinated, and consumed in real time—specifically the Eastern, Western, and Texas Interconnections. The Bulk Power System (BPS) in the contiguous U.S. (including adjacent portions of Canada and Mexico) consists of these three interconnections, which are alternating current (AC) power grids where power flows freely from generating sources to consuming loads. These interconnections are separately planned and operated; they are connected to each other only through low-capacity direct current (DC) tie lines. Each interconnection is managed to maintain a single frequency and to maintain stable voltage levels throughout the interconnection. Physically, each interconnection functions as a large pool, where all electricity delivered to the electric grid flows by displacement over all transmission lines in the interconnection and must be continually balanced with load to ensure reliable electricity service to customers throughout each interconnection. "Since power flows on all transmission paths, it is not uncommon to find circumstances in which part of a power delivery within one balancing area flows on transmission lines in adjoining areas, or part of a power delivery between two balancing areas flows over

areas within the Eastern and Western Interconnections as well as the Texas Interconnection.

the transmission facilities of a third area."[391] The interconnections are the "complex machines" within which EGUs plan, coordinate, and operate, manifesting a degree of both long-term and real-time interdependence that is unique to this industry. We concluded that, absent a compelling reason to adopt a smaller regional scale for evaluation of CO_2 emission reduction opportunities for the electric power sector—which we have not found, as discussed below—the interconnections should be the regions used for evaluation of the BSER for CO_2 emission reductions from the electric power sector because of the fundamental characteristics of electricity, the industry's basic interconnected physical infrastructure, and the interdependence of the affected EGUs within each interconnection.

Second, we considered whether the interconnection subregions for which various planning and operational functions are carried out by separate institutional actors would represent more appropriate regions than the entire interconnections, and concluded that they would not. Interconnection planning and management follows the NERC functional model, which defines subregional areas and regional entities within each interconnection for the purposes of balancing generation with load and ensuring that reliability is maintained. While a variety of organizations plan and operate these subregions, those activities always occur in the context of the interconnections, and the subregions cannot be operated autonomously. The need to maintain

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[391] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 188 (2d ed. 2010)

common frequency and stable voltage levels throughout the interconnections requires constantly changing flows of electricity between the planning and operating subregions within each interconnection.

Because each interconnection is a freely flowing AC grid, any power generated or consumed flows through the entire interconnection in real time; as a result of this highly interconnected nature of the power system, the management of generation and load on the grid must be carefully maintained. This management is carried out principally by subregional entities responsible for the operation of the grid, but this operation must be coordinated in real time to ensure the reliability of the system. Regional operators must coordinate the dispatch of power, not only in their own areas, but also with the other subregions within the interconnection. Although this coordination has always been important, grid planning and management has evolved to be increasingly interconnection-wide, through the development of larger regional entities, such as RTO/ISOs, or large-utility dispatch across multiple balancing areas. As a result, the fact that much of the necessary coordination for the interconnections is performed regionally on a partially decentralized basis (at least in the case of the Eastern and Western Interconnections) or occurs through the operation of automated equipment and the physics of the grid does not render the subregions more relevant than the interconnections as the ultimate regions within which electricity supply and demand must balance.

Moreover, some planning and standard setting activities are undertaken explicitly at the interconnection level. For example, interconnections also have interconnection reliability operating limits (IROLs).[392] A joint FERC-NERC report on the September 8, 2011 Arizona-Southern California outages outlined the importance of IROLs.[393] The report noted that to ensure the reliable operation of the bulk power system, entities must identify a plan for IROLs to avoid cascading outages. "In order to ensure the reliable operation of the BPS, entities are required to identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability."[394]

Congress recognized the significance of the three interconnections in the American Recovery and

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[392] For example, the Eastern Interconnection has Reliability Standard IRO-006-EAST-1, Transmission Loading Relief Procedure for the Eastern Interconnection, *available at http://www.nerc.com/files/IRO-006-EAST-1.pdf* (providing an "Interconnection-wide transmission loading relief procedure (TLR) for the Eastern Interconnection that can be used to prevent and/or mitigate potential or actual System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances to maintain reliability of the Bulk Electric System (BES).").

[393] FERC-NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations* (Apr. 2012), *available at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.*

[394] FERC-NERC, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*, at 97 (Apr. 2012), *available at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.*

Reinvestment Act of 2009 (Recovery Act) when it provided $80 million in funding for interconnection-based transmission planning.[395] In order to fulfill this Congressional mandate, DOE and FERC signed a memorandum of understanding to enumerate their roles "for activities related to the Resource Assessment and Interconnection Planning project funded by the American Recovery and Reinvestment Act of 2009 (Recovery Act). Among the objectives of the project is to facilitate the development or strengthening of capabilities in each of the three interconnections serving the contiguous lower forty-eight States, to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term interconnection-wide transmission plans."[396] DOE issued awards to five organizations that performed work in the Western, Eastern, and Texas Interconnections to develop long-term interconnection-wide transmission expansion plans.[397]

In Order No. 1000, FERC also took a broader regional view of transmission planning.[398] FERC

[395] American Reinvestment and Recovery Act of 2009, Title IV, Public Law 111-5 (2009).

[396] Memorandum of Understanding Between the U.S. Department of Energy and the Federal Energy Regulatory Commission, *available at http://www.ferc.gov/legal/mou/mou-doe-ferc.pdf*.

[397] DOE, *Recovery Act Interconnection Transmission Planning*, *available at http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act*.

[398] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No.

required each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan. FERC also required neighboring transmission planning regions to coordinate with each other. This interregional coordination includes identifying methods for evaluating interregional transmission facilities as well as establishing a common method or methods of cost allocation for interregional transmission facilities.

In addition to Congressional, DOE, and FERC recognition of the importance of the three interconnections, NERC also considers them to be significant. NERC Organizational Standards "are based upon certain Reliability Principles that define the foundation of reliability for North American bulk electric systems."[399] These principles take a broad view of electric system reliability, considering the reliability of interconnected bulk electric systems. For example, Reliability Principle 1 states, "Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC standards."[400] NERC took a

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1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[399] NERC, *Reliability and Market Interface Principles*, at 1, *available at http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf*.

[400] NERC, *Reliability and Market Interface Principles*, at 1, *available at http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf*.

similarly broad view of system reliability when it delegated its authority to monitor and enforce mandatory reliability standards to a single Regional Entity in both the Western and Texas Interconnections (WECC in the West and the Texas Reliability Entity in the ERCOT region of Texas).[401] Moreover, both WECC and ERCOT have interconnection-wide reliability standards.[402] The Eastern Interconnection has multiple reliability regions with some differences in standards, but power flows and reliability are managed through a single Reliability Coordinator Information System that tracks power flows for all transmission transactions.[403]

The importance that Congress, DOE, FERC, and NERC each place upon the interconnections for electric reliability and operational issues is another factor supporting our decision to set the interconnections as the regional boundaries for the establishment of BSER. The utilization of the three interconnections for both planning and reliability

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[401] NERC, *Key Players*, *available at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx*.

[402] WECC, *Standards*, *available at https://www.wecc.biz/Standards/Pages/Default.aspx* (last visited July 3, 2015); Texas Reliability Entity, *Reliability Standards*, *available at http://www.texasre.org/standards_rules/Pages/Default.aspx* (last visited July 3, 2015).

[403] The NERC glossary defines the Reliability Coordinator Information System as the "system that Reliability Coordinators use to post messages and share operating information in real time." NERC, *Glossary of Terms Used in Reliability Standards* (Apr. 20, 2009), *available at http://www.eia.gov/electricity/data/eia411/nerc_glossary_2009.pdf*.

purposes is a clear indication of the importance that electricity system regulators, operators, and industry place upon the interconnections. Those responsible for the electricity system recognize the need to ensure that there is a free flow of electricity throughout each interconnection such that transmission planning and reliability analysis are occurring at the interconnection level. Further, this vigilance with respect to considering reliability from an interconnection-wide basis recognizes that each of the interconnections behaves as a single machine where "outages, generation, transmission changes, and problems in any one area in the synchronous network can affect the entire network."[404] By setting the three interconnections as the regions for purposes of BSER, we are acting consistent with the way in which planning, reliability, and industry experts view the electricity system.

An additional factor weighing against the use of planning or operational subregions of the interconnections as the regions for our BSER analysis for this rule is that the borders of those subregions occasionally change as planning and management functions evolve or as owners of various portions of the grid change affiliations. This is not a merely theoretical consideration; numerous ISO/RTO and other regional boundaries have substantially changed in recent years. For example, in 2012, Duke Energy Ohio and Duke Energy Kentucky integrated into

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[404] Casazza, J. and Delea, F., *Understanding Electric Power Systems*, IEEE Press, at 159 (2d ed. 2010).

PJM.[405] The following year, in December 2013, Entergy and its six utility operating companies joined MISO, creating the MISO South Region.[406] The integration of MISO South correspondingly led to changes in NERC's regional assessment areas.[407] FERC also recently approved the integration of the Western Areas Power Administration—Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District into SPP.[408] Additionally, PacifiCorp and the CAISO recently

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[405] PJM, *Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc., Successfully Integrated Into PJM* (Jan. 3, 2012), *available at http://www.pjm.com/~/media/about-pjm/newsroom/2012-releases/20120103-duke-ohio-and-kentucky-integrate-into-pjm.ashx.*

[406] *South Region Integration*, *available at https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/SouthernRegionIntegration/Pages/SouthernRegionIntegration.aspx* (noting that the creation of the MISO South Region "brought over 18,000 miles of transmission, ~50,000 megawatts of generation capacity, and ~30,000 MW of load into the MISO footprint.").

[407] NERC previously included Entergy and its six operating areas as part of the SERC Assessment Areas. NERC, *2014 Summer Reliability Assessment* (May 2014), *available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf*. "MISO now coordinates all RTO activities in the newly combined footprint, consisting of all or parts of 15 states with the integration of Entergy and other MISO South entities. This transition has led to substantial changes to MISO's market dispatch, creating the potential for unanticipated flows across the following systems: Tennessee Valley Authority (TVA), Associated Electric Cooperative Inc. (AECI), and Southern Balancing Authority." *Id. at 7.*

[408] SPP, *FERC approves Integrates System joining SPP* (Nov. 12, 2014), *available at http://www.spp.org/publications/FERC%20approves%20IS%20membership.pdf.*

began operating the western Energy Imbalance Market (EIM).[409] Other entities such as NV Energy, Arizona Public Service Co., and Puget Sound Energy are planning to participate in the EIM in the future.[410] The EIM "creates significant reliability and renewable integration benefits for consumers by sharing and economically dispatching a broad array of resources."[411] This history of changing regional boundaries leads us to the conclusion that selecting smaller regional boundaries for purposes of setting the BSER would merely represent a snapshot of current, changeable regional boundaries. As we have seen with recent, large-scale changes regarding ISO/RTO boundaries and NERC reliability assessment areas, such regions would likely not stand the test of the time, nor would smaller regional boundaries accurately reflect electricity flows on the grid. The EPA believes that the interconnections are the most stable and reasonable regional boundaries for setting BSER.

Third, we considered whether transmission constraints, and the fact that the specific locations of generation resources and loads within each interconnection clearly matter to grid planning and operations, necessitate evaluation of the emission reductions available from the building blocks at scales

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[409] NREL, *Energy Imbalance Market*, *available at http://www.nrel.gov/electricity/transmission/energy_imbalance.html*.

[410] CAISO, *EIM Company Profiles* (May 2015), *available at http://www.caiso.com/Documents/EIMCompanyProfiles.pdf*.

[411] CAISO, *Energy Imbalance Market*, *available at http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx*.

smaller than the interconnections. We concluded that no reduction in scale was needed due to such constraints. The same industry trends that are reflected in the BSER—the changing efficiencies and mix of existing fossil EGUs and the development of RE throughout each interconnection—as well as the management of the interconnected grid as loads are reduced through EE, which is not reflected in the final BSER, are already driving power system development and are being managed through interconnection-wide planning, coordination and operations, and will continue to be managed in that manner in the future with or without this rule. While electricity supply and demand must be balanced in real time in a manner that observes all security constraints at that point in time, and key aspects of that management are carried out at a subregional scale, the emissions standards established in this rule can be met over longer timeframes through processes managed at larger geographic scales, just as they are today. We believe this rule will reinforce these developments and help provide a secure basis for moving forward. If a local transmission constraint requires that for reliability reasons a higher-emitting resource must operate during a certain period of time in preference to a lower-emitting resource that would otherwise be the more economic choice when all costs are considered, nothing in this rule prevents the higher-emitting source from being operated. If the same transmission constraint causes the same conditions to occur frequently, the extra cost associated with finding alternative ways to reduce emissions will provide an economic incentive for concerned parties to explore ways to relieve the transmission constraint. If relieving the constraint would be more costly than employing alternative measures to reduce emissions, the rule allows parties to pursue those alternative emission reduction measures. Accommodation of intermittent constraints and evaluation of alternatives for relieving or working around them have been routine operating and planning practices within the utility power sector for many years; the rule will not change these basic economic practices that occur today. The 2022–29 schedule for the rule's interim goals and the 2030 schedule for the rule's final goals allow time for planning and investment comparable to the sector's typical planning horizons.

Finally, the EPA also considered whether the smaller geographic scales on which affected EGUs may typically engage in energy and capacity transactions necessitate evaluating the emission reductions available from the building blocks at scales smaller than the interconnections, and again concluded that a smaller scale was not necessary or justified. We first note that electricity trading occurs today throughout the interconnection through RTO/ISO markets and active spot markets, often over large areas such as RTO/ISOs, or managed over large dispatch areas outside RTOs. These trades result in interconnection-wide changes in flow that are managed in real time. Moreover, the exchange of power is not limited to these areas. For example, RTOs regularly manage flows between RTOs, and EGUs near the boundaries of RTOs impact multiple subregions across the interconnections, so that any subregional boundaries that might be evaluated for potential relevance as trading region boundaries will change as conditions and EGU choices change, while interconnection boundaries will remain stable.

In addition, the final rule permits trading of rate-based emission credits or mass-based emission allowances. Emission allowances and other commodities associated with electricity generation activities, such as RECs, which, again, represent investments in pollution control measures, are already traded separately from the underlying electric energy and capacity. There is no reason that whatever geographic limits may exist for electricity and capacity transactions by an affected EGU should also limit the EGU's transactions for validly issued rate-based emission credits or mass-based emission allowances. In fact, as discussed below, the final rule not only allows national trading without regard to the interconnection boundaries, but also includes a number of options that readily facilitate states' and utilities' very extensive reliance on emissions trading. It is appropriate for the rule to take this approach, in part, because the non-local nature of the impacts of CO_2 pollution do not necessitate geographic constraints, and in the absence of a policy reason to constrain the geographic scope of trading, the largest possible scope is the most efficient scope.

f. Uniform CO_2 emission performance rates by technology subcategory. In conjunction with the refinements to the interpretations of section 111 reflected in the final rule, the EPA has refined the methodology for applying the BSER to the affected EGUs so as to incorporate performance rates that are uniform across technology subcategories.

Specifically, the final rule establishes a performance rate of 1305 lbs. per net MWh for all affected steam EGUs nationwide and a performance rate of 771 lbs. per net MWh for all affected stationary combustion turbines nationwide. The computations of these performance rates and the determinations of state goals reflecting the performance rates are described in sections VI and VII of the preamble, respectively. As described above, in its proposed rule and NODA, the EPA solicited comment on a number of proposals to reflect the regional nature of the electricity system in the methodology for quantifying the emission limitations reflective of the BSER. At the same time, the EPA also consistently emphasized the need for strategies to ensure the achievability and flexibility of the established emission limitations and to increase opportunities for interstate and industry-wide coordination. This modification is consistent with a number of comments we received in response to those proposals. The commenters took the position that the proposed state goals varied too much among states and unavoidably implied, or would inevitably result in, states establishing inconsistent standards of performance for sources of the same technology type in their respective states, which in the commenters' view was not appropriate under section 111.

Having determined to adopt regional alternatives for computing the emission reductions achievable under each building block, the EPA has further determined to exercise discretion not to subcategorize based on the regions, and instead to apply a nationally uniform CO_2 emission performance rate for each source subcategory. Evaluating the emission reduction opportunities achievable through application of the BSER on a broad regionalized basis, which is appropriate for the reasons discussed above, makes it possible to express the degree of emission limitation reflecting the BSER as CO_2 emission performance rates that are uniform for all affected EGUs in a technology subcategory within each region. However, the goals and strategies embodied in the EPA's proposed rule are best effected by setting uniform emission performance rates nationally and not just regionally, as recognized by commenters favoring the use of nationally uniform performance rates by technology subcategory. Nationally uniform emission performance rates create greater parity among the emission reduction goals established for states across the contiguous U.S. and increase the ability of states and affected EGUs to coordinate emission reduction strategies, including through the use of emission trading mechanisms if states choose to allow such mechanisms, which we consider likely.

Having determined that the performance rates computed on a regional basis merit consideration as nationally applicable performance rates, we are also determining that the objectives of achievability and flexibility would best be met by using the least stringent of the regional performance rates for the three interconnections for each technology subcategory as the basis for nationally uniform performance rates for that technology subcategory rather than by using the most stringent of the regional performance rates.[412] Under this approach, the CO_2

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[412] The Eastern, Western, and Texas Interconnections each encompass large and diverse populations of EGUs with numerous and diverse opportunities to reduce CO_2 emissions through application of the measures in each of the three building blocks.

emission performance rate reflecting the BSER for all steam EGUs is uniform across the contiguous U.S., regardless of the state or interconnection where the steam EGUs are located. While it is true that steam EGUs in the Western and Texas Interconnections have opportunities to implement the measures in the building blocks to a greater extent than the steam EGUs in the Eastern Interconnection—for example, under building block 2, they have relatively greater amounts of incremental NGCC generation available to replace their generation in all years for which performance rates were computed—we do not conclude that this means that the EGUs in all three interconnections should be assigned the most stringent CO_2 emission performance rate computed for any of the three regions. Applying nationally the performance rate computed for the interconnection with the lease stringent rate ensures that the emission limitations are achievable by the affected EGUs in all three interconnections. The use of a common CO_2 emission performance rate across all of the steam EGUs in all three regions also allocates the burdens of the BSER equally across the steam EGU source subcategory. The same is true for the combustion turbine source subcategory, even though, in any year for which emission performance rates are computed, the combustion turbines in two of the interconnections have relatively greater opportunities to replace their

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Based on these considerations of scale and diversity, we conclude that each of the interconnections is sufficiently representative of the source subcategories and emission reduction opportunities encompassed in the BSER to potentially serve as the basis for CO_2 emission performance rates applicable to the respective source subcategories on a nationwide basis.

generation with generation from new RE generating capacity than combustion turbines in the third interconnection.[413]

In addition, using the least stringent rate provides greater "headroom"—that is, emission reduction opportunities beyond those reflected in the performance rates—to affected EGUs in the interconnections that do not set the nationwide level. This greater "headroom" provides greater nationwide compliance flexibility and assurance that the standards set by the states based on the emission guidelines will be achievable at reasonable cost and without adverse impacts on reliability. This is because affected EGUs in the interconnections that do not set the nationwide level have more opportunities to directly invest in each of the building blocks in their respective regions, and affected EGUs in the interconnection that does set the nationwide level may in effect invest in the opportunities in the other interconnections through trading. At the same time, our approach still represents the degree of emission limitation achievable through use of an appropriately

[413] As discussed in section VI and the CO_2 Emission Performance Rate and State Goal Computation TSD, the emission performance rates for each technology subcategory are computed by region for each year from 2022 through 2030, and the region with the least stringent emission rate for a particular subcategory, whose rate therefore is used for all three regions, can differ across years. In the case of the steam EGU subcategory, the nationwide rate for all years is the rate computed for the Eastern Interconnection. In the case of the NGCC subcategory, the nationwide rate is the rate computed for the Texas Interconnection for the years from 2022 through 2026 and the rate computed for the Eastern Interconnection for the years from 2027 through 2030.

large and diverse set of emission reduction opportunities and can therefore reasonably be considered the "best" system of emission reduction for each technology subcategory.

Our approach in this rulemaking thus not only addresses the comments we received regarding potentially disparate impacts of the approach presented in the proposal, it is also generally consistent with the approach we have taken in other NSPS rulemakings, where standards of performance or emission guidelines have typically been established at uniform stringencies for all units in a given source subcategory, and where once the best system of emission reduction has been identified, stringencies are generally set based on what is reasonably achievable using that system.

Providing each state with a state-specific weighted average rate-based goal allows the state to determine how the emission reduction requirements should be allocated among the state's affected EGUs. We continue to believe that, as in the proposal, this is an important source of flexibility for states in developing their section 111(d) plans. Accordingly, in this final rule we are providing uniform CO_2 emission performance rates for each source subcategory and also translating those rates to state-specific weighted average rate-based goals. For additional flexibility, we are also translating the state-specific rate-based goals into state-specific mass-based goals. Our determinations of the emission performance rates are described in section VI below, and our determinations of the rate-based and mass-based state goals are described in section VII below.

We note here that the weighted-average state goals reflect the application of the uniform CO_2 emission performance rates for affected steam EGUs and affected NGCC units to the respective units in each subcategory in each state. Each 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. Compared to the computation approach reflected in the proposed state goals, the revised approach to quantify the BSER on a regional basis and to translate the results into nationally uniform emission performance rates by source subcategory results in more stringent goals (compared to the proposal) for states whose generation has historically been most heavily concentrated at coal-fired steam EGUs. This shift is an expected consequence of the use of uniform performance rates by source subcategory. At proposal, these states' goals reflected artificial assumptions in the selected goal quantification methodology that to a considerable extent limited their emission reduction opportunities based on their states' borders, and the proposed goals therefore were less stringent in states which had substantial coal generation and little local NGCC capacity. The final rule more realistically recognizes that emission reduction opportunities, like other aspects of the interconnected electricity system, are regional and are not constrained by state borders. The final rule also reflects the EPA's emphasis in the proposal on ensuring the achievability and flexibility of the emission guidelines and increasing opportunities for interstate and industry-wide coordination. We consequently apply the same emission performance rates to coal-fired units in states with heavy reliance on coal-fueled generation as we do to coal-fired units in other states, which produces more stringent state goals than at proposal for the states with the highest concentrations of coal-fired generation. At the same time, the final goals for some states are less stringent than their proposed goals. For example, a goal based on the least stringent regional rates is less stringent for some states than a goal based on state-specific emission reduction opportunities would be. Accordingly, the differences among the final state goals are generally smaller than the differences among the proposed state goals. All of the final rate-based state goals are necessarily in the range bounded by the CO_2 emission performance rate for NGCC units and the CO_2 emission performance rate for steam EGUs because all of the state goals are computed as a weighted average of those two performance rates, and this range is narrower than the range of state goals in the proposal.

The computations of the uniform CO_2 emission performance rates are shown in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. These uniform emission performance rates are applicable to the states and areas of Indian country [414] located in the contiguous U.S. that have

[414] As explained in section III.A. above, an Indian tribe whose area of Indian country has affected EGUs will have the opportunity but not the obligation to seek authority to develop and implement a section 111(d) plan. If no tribal plan is approved, the EPA has the responsibility to establish a plan if it determines that such a plan is necessary or appropriate.

affected EGUs.[415] We have not in this rule applied the uniform emission performance rates to Alaska, Hawaii, Puerto Rico, or Guam—states and territories that have otherwise affected EGUs but are isolated from the three major interconnections—and will determine how to address the requirements of section 111(d) with respect to these jurisdictions at a later time. Further discussion regarding the isolated jurisdictions can be found in section VII.F. of the preamble.

g. *Establishment of a 2022–2029 interim compliance period*. The June 2014 proposal separately quantified emission limitations applicable to an interim 2020–29 period and to the period beginning in 2030. The EPA took broad comment on this proposed timing. Although the proposal provided flexibility in the timing with which emission reductions could be made over the course of the 2020–2029 period in order to achieve compliance with the emission limitations applicable to that interim period, many commenters perceived the start of the period as too soon and stated that it provided insufficient time for planning and investments necessary for sources to begin implementation activities while maintaining reliable electricity supplies.

The EPA has considered these comments and in the final rule has established an interim compliance period of 2022–2029, providing two additional years for planning and investment before the start of compliance. We are persuaded by comments and by our own further analysis that this timeframe is appropriate and will, in combination with the glide

[415] As noted earlier, there are currently no affected EGUs in Vermont or the District of Columbia.

path of emission reductions reflected in the final building blocks and the states' flexibility to define their own paths of emission reductions over the interim period (as discussed in section VIII), provide adequate time for necessary planning and investment activities. This will enable the final rule's requirements to be implemented in an orderly manner while reliability of electricity supplies is maintained. Further discussion is provided in the sections of the preamble addressing the individual building blocks (sections V.C., V.D., and V.E.) and on electricity system reliability (section VIII.G.2.).

The initial compliance date of 2022, coupled with the fact that the 2030 standard is phased in over the subsequent eight years, affords affected EGUs the benefit of having an extended planning period before they need to incur any significant obligations. Where needed, states may take the period through September 2018 to develop their final plans, and affected EGUs will be able to work with the states during that period to develop compliance approaches. States will also have the flexibility to select their own emissions trajectories in such a way that certain emission reduction measures could be implemented later in the interim period (again, provided that their affected EGUs still meet the interim performance rates or interim goal over the interim period as a whole). As a result, if the affected EGUs in those states need to incur any expenses before the adoption of the final state plans, those expenses need not be more than minimal. It is worth noting that an earlier state plan submission date provides regulated sources with more certainty and time to plan for compliance, but has no effect on the time when compliance must be achieved, as the mandatory compliance period begins in 2022 for all states. Some states that already have established programs for limiting CO_2 emissions from power plants may adopt and submit to the EPA state plans by September 6, 2016. In those states, sources will already have developed compliance approaches to meet state law requirements. Other states that submit plans by September 6, 2016, may be expected to work with their affected EGUs to determine a reasonable compliance approach, in light of the fact that compliance is not required to begin until 2022. It is also possible that some states will submit neither final state plans nor initial submittals by September 6, 2016, and that the EPA will promulgate federal plans. Sources in those states will have more than five years to meet their 2022 compliance obligations, a lengthy period that will afford them the opportunity to plan before incurring significant expenditures.

These periods of time are consistent with current industry practice in changing generation or adding new generation. For example, in June 2015, Alabama Power Company announced plans to acquire 500 MW of RE generation over the next six years. This amount would make up between four and five percent of Alabama Power's generation mix.[416] In addition, the

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[416] Alabama Power Co., "Petition for a Certificate of Convenience and Necessity," submitted to the Alabama Public Service Commission (June 25, 2015) (petition requests "a certificate of convenience and necessity for the construction or acquisition of renewable energy and environmentally specialized generating resources and the acquisition of rights and the assumption of payment obligations under power purchase arrangements pertaining to renewable energy and environmentally specialized generating resources, together with all transmission facilities, fuel supply and transportation

study of utility IRPs placed in the docket for this rulemaking [417] shows that sources are able to replace coal-fired generation with natural-gas fired generation and add incremental amounts of RE (as well as take other actions, such as implement demand-side EE programs), on a gradual basis, after a several-year lead time, over an extended period, as provided for under the final rule.

h. *Refinements to stringency for individual building blocks*. For each individual building block, the EPA has reexamined the data and assumptions used at proposal in light of comments solicited and has made a number of refinements in the final rule based on that information. The refinements are discussed in the preamble sections for each building block (sections V.C., V.D., and V.E.) and emission performance rate computation (section VI) and in the GHG Mitigation Measures TSD for the CPP Final Rule and the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule. As previously noted, viewed in terms of projected nationwide emission reductions (but not necessarily with respect to each individual state), these refinements generally tend to make the interim goals somewhat less stringent than at proposal and the 2030 goals somewhat more

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arrangements, appliances, appurtenances, equipment, acquisitions and commitments necessary for or incident thereto") (included in the docket for this rulemaking). *See* Swartz, Kristi, "Alabama Power plan would dramatically boost its renewables portfolio," E&E Publishing, July 16, 2015.

[417] See memorandum entitled "Review of Electric Utility Integrated Resource Plans" (May 7, 2015) available in the docket.

stringent than at proposal. In addition to the changes described above, the refinements include the following:

- Use of regional rates ranging from 2.1 percent to 4.3 percent (rather than 6 percent) as the average heat rate improvement opportunity achievable by steam units under building block 1.
- Use of 75 percent of summer capacity (rather than 70 percent of nameplate capacity) as the target capacity factor for existing NGCC units under building block 2.
- Use of updated information from the National Renewable Energy Laboratory (NREL) on RE costs and potential, and revision of the list of quantified RE technologies to exclude landfill gas under building block 3.

4. Determination of the BSER

In this rule, the EPA is finalizing as the BSER a combination of building blocks 1, 2, and 3, with refinements as discussed below. The building blocks constitute the BSER from the perspective of the source category as a whole. Each building block can be implemented through standards of performance set by the states and includes a set of actions that individual sources can use to achieve the emission limitations reflecting the BSER. These actions and mechanisms, which include reduced generation and emissions trading approaches where the state-set standards of performance incorporate trading and which may be understood as part of the BSER, will be discussed below in section V.A.5. Each of the building blocks consists of measures that the source category and individual affected EGUs have already demonstrated the ability to implement. In quantifying the application of each building block, the EPA has identified reasonable levels of stringency rather than the maximum possible levels.

As discussed above, one of the modifications being made in this rule is the establishment of uniform performance rates by technology subcategory, which enhances the rule's achievability and flexibility and facilitates coordination among the states and across the industry. However, in the first instance, the emission reductions achievable through use of the building blocks are being evaluated on a regional basis that reflects the regional nature of the interconnected electricity system and the region-wide scope of opportunities available for affected EGUs to access emission reduction measures. The EPA recognizes that the emission reduction opportunities under these building blocks vary by region because of regional differences in the existing mix of types of fossil fuel-fired EGUs and the available opportunities to increase low- and zero-carbon generation. Consequently, in order to achieve uniform performance rates by technology subcategory, while respecting these regional differences in emission reduction opportunities, we have determined that it is reasonable not to establish the stringency of the BSER separately by region based on the maximum emission reduction that would be achievable in that region, but instead to establish uniform stringency across all regions at a level that is achievable at reasonable cost in any region. Thus, for each technology subcategory, the BSER is the combination of the elements described above at the combined stringency that is reasonably achievable in the region where the CO_2 emission performance rates determined to be achievable at reasonable cost by the EGUs in that subcategory through application of the building blocks were least stringent.[418]

This approach is consistent with the EPA's efforts to enhance the achievability and flexibility of the rule and to promote interstate and industry coordination and reflects the regional strategies emphasized in the proposal and the NODA. It is also consistent with the approach we have taken in other NSPS rulemakings, where the degree of emission limitation achievable through the application of the BSER for each subcategory of affected sources generally has been determined not on the basis of what is achievable by the sources that can reduce emissions most easily, but instead on the basis of what is reasonably achievable through the application of the BSER across a range of sources. This approach also provides compliance headroom—in addition to the headroom provided by our approach to setting the stringency for each individual building block—for affected EGUs in regions where additional emission reductions can be achieved at reasonable cost, thereby promoting nationwide compliance flexibility. Further, because we are authorizing states to establish standards of

[418] The determinations of stringency for each source subcategory were made independently for each year from 2022 through 2030, and in the case of the NGCC category, the limiting region changed over time. Thus, for the NGCC category, the uniform CO_2 emission performance rate is based on the stringency achievable in the Texas Interconnection for the years from 2022 through 2026 and the stringency achievable in the Eastern Interconnection for the years from 2027 through 2030. For the steam EGU subcategory, the uniform CO_2 emission performance rate is based on the stringency achievable in the Eastern Interconnection in all years.

performance that incorporate trading without geographic restrictions, the opportunity of affected EGUs to engage in emissions trading, to the extent allowed under the relevant section 111(d) plans, ensures the availability of additional, lower-cost emission reduction opportunities in other regions that will also promote compliance flexibility and reduce compliance costs.

As discussed in section XI of the preamble and the Regulatory Impact Analysis, application of the BSER determined as summarized above is projected to result in substantial and meaningful reductions of CO_2 emissions.

Briefly, the elements of the BSER are:

Building block 1: Improving heat rate at affected coal-fired steam EGUs in specified percentages.

Building block 2: Substituting increased generation from existing affected NGCC units for generation from affected steam EGUs in specified quantities.

Building block 3: Substituting generation from new zero-emitting RE generating capacity for generation from affected EGUs in specified quantities.

a. *Building block 1.* Building block 1—improving heat rate at affected coal-fired steam EGUs—is a component of the BSER with respect to coal-fired steam EGUs [419] because the measures the affected

[419] For the reasons discussed in the proposal, the EPA is not determining that heat rate improvements at other types of affected EGUs, such as NGCC units and oil-fired and natural gas-fired steam EGUs, are components of the BSER. However, all types of affected EGUs would be able to employ heat rate improvements as measures to help achieve compliance with their assigned standards of performance.

EGUs may undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and perform well with respect to other factors relevant to a determination of the "best system of emission reduction . . . adequately demonstrated." Building block 1 is a "system of emission reduction" for steam EGUs because owners of these EGUs can take actions that will improve their heat rates and thereby reduce their rates of CO_2 emissions with respect to generation.

The EPA has analyzed the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable through heat rate improvements at coal-fired steam EGUs based on engineering studies and on these EGUs' reported operating and emissions data. We conclude that taking action to improve heat rates is a common and well-established practice within the industry that is capable of achieving meaningful reductions in CO_2 emissions at reasonable cost, although, as discussed earlier, we also conclude that the quantity of emission reductions achievable through heat rate improvement measures is insufficient for these measures alone to constitute the BSER. Specifically, we have determined that an average heat rate improvement ranging from 2.1 to 4.3 percent by all affected coal-fired EGUs, depending on the region, is an element of the BSER, based on the inclusion of those amounts of improvement in the three regions, determined through our regional analysis. Our analysis and conclusions are discussed in Section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below.

Consideration of other BSER factors also favors a conclusion that building block 1 is a component of the BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of, and therefore the adverse impacts associated with, disposal of coal combustion solid waste products. By definition, heat rate improvements do not cause increases in net energy usage. Although we are justifying building block 1 as part of the BSER without reference to technological innovation, we also consider technological innovation in the alternative, and we note that building block 1 encourages the spread of more advanced technology to EGUs currently using components with older designs.

As noted in the June 2014 proposal, the EPA is concerned about the potential "rebound effect" associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO_2 emissions (depending on the CO_2 emission rates of the displaced generating capacity). Unless mitigated, the occurrence of a rebound effect would reduce the emission reductions achieved by building block 1, exacerbating the inadequacy of emission reductions that is the basis for our conclusion that building block 1 alone would not represent the BSER for this industry. However, we believe that our concern about the potential rebound effect can be readily addressed by ensuring that the BSER also reflects other CO_2 reduction strategies that encourage increases in generation from lower- or zero-carbon EGUs, thereby allowing building block 1 to be considered an appropriate part of the BSER for CO_2 emissions at affected EGUs as long as the building block is applied in combination with other building blocks.

b. *Building block 2.* Building block 2—substituting generation from less carbon-intensive affected EGUs (specifically "existing" NGCC units, meaning units that were operating or had commenced construction as of January 8, 2014) for generation from the most carbon-intensive affected EGUs—is a component of the BSER for steam EGUs because generation shifts that will reduce the amount of CO_2 emissions at higher-emitting EGUs and from the source category as a whole are technically feasible, are of reasonable cost, and perform well with respect to other factors relevant to a determination of the "best system of emission reduction . . . adequately demonstrated." Building block 2 is a "system of emission reduction" for steam EGUs because incremental generation from existing NGCC units will result in reduced generation and emissions from steam EGUs, and owners of steam EGUs can, and many do, invest in incremental generation from NGCC units through a variety of possible mechanisms. A steam EGU investing in incremental generation from NGCC units may choose to reduce its own generation or may maintain its generation level and choose to allow the reduction in generation to occur at other steam EGUs through the coordinated planning and operation of the interconnected electricity system. An affected EGU may also invest in emission reductions from building block 2 through the mechanism of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable at high-emitting EGUs through generation shifts to lower-emitting affected EGUs are discussed in Section V.D. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider generation shifts among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. In the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through mechanisms—in some cases centralized and in others not—that regularly deal with such changes on both a short-term and a longer-term basis. Our analysis demonstrates that the emission reductions that can be achieved or supported by such generation shifts are substantial and of reasonable cost. Further, both the achievability of this building block and the reasonableness of its costs are supported by the fact that there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation for a variety of reasons.

Building block 2 is adequately demonstrated as a "system of emission reduction" for affected steam EGUs. As discussed in section V.B., since the time of the 1970 CAA Amendments, the utility power sector has recognized that generation shifts are a means of controlling air pollutants; in the 1990 CAA Amendments, Congress recognized that generation shifts among EGUs are a means of reducing emissions from this sector; and generation shifts similarly have been recognized as a means of reducing emissions under trading programs established by the EPA to implement the Act's provisions. It is common practice in the industry to account for the cost of emission allowances as a variable cost when making security-constrained, cost-based dispatch decisions; doing so integrates generation shifts into the operating practices used to achieve compliance with environmental requirements in an economical manner. These industry trends are further discussed in section V.D. Thus, legislative history, regulatory precedent, and industry practice support interpreting the broad term "system of emission reduction" as including substituting lower-emitting generation for higher-emitting generation through generation shifts among affected EGUs.

An important additional consideration supporting the determination that building block 2 is adequately demonstrated as a "system of emission reduction" is that owners of affected steam EGUs have the ability to invest in generation shifts as a way of reducing emissions. The owner of an affected EGU could invest in such generation shifts in several ways, including by increasing operation of an NGCC unit that it already owns or by purchasing an existing NGCC unit and increasing operation of that unit. Increases in generation by NGCC units over baseline levels can also serve as the basis for creation of CO_2 ERCs—that is, instruments representing the ability of incremental electricity generated by NGCC units to cause emission reductions at affected steam EGUs, as distinct from the incremental electricity itself. Again, it is important to note that the acquisition of such ERCs represents an investment in the actions of the facility or facilities whose alteration of utilization levels generated the emissions rate improvement or reduction. In the context of the BSER, purchase of instruments representing the emissions-reducing benefit of an action is simply a medium of investment in the underlying emissions reduction action. These mechanisms are discussed further in section V.A.5. In this rule, the EPA is establishing minimum criteria for the creation of valid ERCs by NGCC units and for the use of such ERCs by affected steam EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling ERCs. The minimum criteria are discussed in section VIII of this preamble.

We note that an affected EGU investing in building block 2 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective emission reduction requirements that will be imposed on affected EGUs in order to meet the emissions standards representing the BSER, an increase in NGCC generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective emission reduction requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected steam EGU. Measures taken by affected EGUs that result in emission reductions from other EGUs in the source category may appropriately be deemed measures to implement or apply the "system of emission reduction" of substituting lower-emitting generation for higher-emitting generation.

Consideration of other BSER factors also supports a determination to include building block 2 as a component of the BSER. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.[420] With respect to energy

[420] For example, according to a DOE/NETL study, the relative amount of water consumption for a new pulverized coal plant is 2.5 times the consumption for a new NGCC unit of similar size. "Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity," Rev

impacts, building block 2 represents replacement of electrical energy from one generator with electrical energy from another generator that consumes less fuel, so the overall energy impact should be a reduction in fuel consumption by the overall source category as well as by individual affected coal-fired steam EGUs. Although for purposes of this rule we consider the incentive for technological innovation only in the alternative, we note that building block 2 promotes greater use of the NGCC technology installed in the existing fleet of NGCC units, which is newer and more advanced than the technology installed in much of the older existing fleet of steam EGUs. For all these reasons, the measures in building block 2 qualify as a component of the "best system of emission reduction . . . adequately demonstrated."

It should be observed that, by definition of the elements of this building block, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking.[421] Through application of this building block considered in isolation, some affected EGUs—mostly coal-fired steam EGUs—would reduce their generation and CO_2 emissions, while other affected EGUs—NGCC units—would increase their generation and CO_2 emissions. However, because for each MWh

2a, September 2013, National Energy Technology Laboratory Report DOE/NETL-2010/1397. EPA believes the difference would on average be even more pronounced when comparing existing coal and NGCC units.

[421] For purposes of this rulemaking, "existing" EGUs include units under construction as of January 8, 2014, the date of publication in the **Federal Register** of the proposed carbon pollution standards for new fossil fuel-fired EGUs.

of generation, NGCC units produce fewer CO_2 emissions than coal-fired steam EGUs, the total quantity of CO_2 emissions from all affected EGUs in aggregate would decrease without a reduction in total electricity generation. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a highly substitutable service, and in the context of CO_2 emissions, where location is not a consideration (in contrast with other pollutants), a measure that takes advantage of that integration to reduce CO_2 emissions from the overall set of affected EGUs is readily understood as a means to implement a "system of emission reduction" for CO_2 emissions at affected EGUs even if the measure would increase CO_2 emissions from a subset of those affected EGUs. Indeed, some industry participants are already moving in this direction for this purpose (while other participants are moving in the same direction for other purposes). Standards of performance that incorporate emissions trading can facilitate the implementation of such a "system" and such approaches have already been used in the electricity industry to address CO_2 as well as other pollutants, as discussed above.

c. *Building block 3.* Building block 3—substituting generation from expanded RE generating capacity for generation from affected EGUs—is a component of the BSER because the expansion and use of renewable generating capacity to reduce emissions from affected EGUs is technically feasible, is of reasonable cost, and performs well with respect to other factors relevant to a determination of the "best system of emission reduction . . . adequately demonstrated." Building block 3 is a "system of emission reduction" for all affected EGUs because incremental RE generation will result in reduced generation and emissions from affected EGUs, and owners or operators of affected EGUs can apply or implement building block 3 through a number of actions. For example, they can invest in incremental RE generation either directly or through the purchase of ERCs. An affected EGU investing in incremental RE generation may choose to reduce its own generation by a corresponding amount or may choose to allow the reduction in generation to occur at other affected EGUs through the coordinated planning and operation of the interconnected electricity system. An affected EGU can also invest in RE generation by means of engaging in emissions trading where the EGU is operating under a standard of performance that incorporates trading.

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of the measures in building block 3 are discussed in Section V.E. below. Additional analysis and conclusions with respect to cost reasonableness are discussed in section V.A.4.d. below. We consider construction and operation of expanded RE generating capacity to be proven, well-established practices within the industry consistent with recent industry trends. States are already pursuing policies that encourage production of greater amounts of RE, such as the establishment of targets for procurement of renewable generating capacity. Moreover, as discussed earlier, markets are likely to develop for ERCs that would facilitate investment in increased RE generation as a means of helping sources comply with their standards of performance; indeed, markets for RECs, which similarly facilitate investment in RE for other purposes, are already well-established. As noted in Section V.A.5. below, an allowance system or tradable emission rate system would provide incentives for affected EGUs to reduce their emissions as much as possible where such reductions could be achieved economically (taking into account the value of the emission credits or allowances), including by substituting generation from new RE generating capacity for their own generation, or could provide a mechanism, as stated above, for such sources to invest in or acquire such generation.

Building block 3 is adequately demonstrated as a "system of emission reduction" for all affected EGUs. As discussed in section II, RE generation has been relied on since the 1970s to provide energy security by replacing some fossil fuel-fired generation. Both Congress and the EPA have previously established frameworks under which RE generation could be used as a means of achieving emission reductions from the utility power sector, as discussed in section V.B. Investment in RE generation has grown rapidly, such that in recent years the amount of new RE generating capacity brought into service has been comparable to the amount of new fossil fuel-fired capacity. Rapid growth in RE generation is projected to continue as costs of RE generation fall relative to the costs of other generation technologies. These trends are further discussed in section V.E. Interpretation of a "system of emission reduction" as including RE generation for purposes of this rule is thus supported by legislative history, regulatory precedent, and industry practice.

Also supporting the determination that building block 3 is adequately demonstrated as a "system of emission reduction" is the fact that owners of affected

EGUs have the ability to invest in RE generation as a way of reducing emissions. As with building block 2, this can be accomplished in several ways. For example, the owner of an affected EGU could invest in new RE generating capacity and operate that capacity in order to obtain ERCs. Alternatively, the affected EGU could purchase ERCs created based on the operation of an unaffiliated RE generating facility, effectively investing in the actions at another site that allow CO_2 emission reductions to occur. These mechanisms are discussed further in section V.A.5. As with building block 2, in this rule the EPA is establishing minimum criteria for the creation of valid ERCs by new RE generators and for the use of such ERCs by affected EGUs for demonstrating compliance with emission rate-based standards of performance established under state plans. The existence of minimum criteria will ensure that crediting mechanisms are feasible and will facilitate the development of organized markets to simplify the process of buying and selling credits. The minimum criteria are discussed in section VIII of the preamble.

As with building block 2, an affected EGU investing in building block 3 to reduce emissions may, but need not, also choose to reduce its own generation as part of its approach for meeting the standard of performance assigned to it by its state. Through the coordinated operation of the integrated electricity system, subject to the collective requirements that will be imposed on affected EGUs in order to meet the emissions standards representing the BSER, an increase in RE generation will be offset elsewhere in the interconnection by a decrease in other generation. Because of the need to meet the collective requirements, the decrease in generation resulting from that coordinated operation is most likely to be generation from an affected EGU. Measures taken by affected EGUs that result in emission reductions from other sources in the source category may appropriately be deemed methods to implement the "system of emission reduction."

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. Generation from wind turbines and solar voltaic installations, two common renewable technologies, does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. With respect to energy impacts, fossil fuel consumption will decrease both for the source category as a whole and for individual affected EGUs. Although the variable nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators to address possible changes in operating reserve requirements, renewable generation has grown quickly in recent years, as discussed above, and grid planners and operators have proven capable of addressing any consequent changes in requirements through ordinary processes. The EPA believes that planners and operators will be similarly capable of addressing any changes in requirements due to future growth in renewable generation through ordinary processes, but notes that in addition, the reliability safety valve in this rule, discussed in section VIII.G.2, will ensure the absence of adverse energy impacts. With respect to technological innovation, which we consider for the BSER only in the alternative, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. For all these reasons, the measures in building block 3 qualify as a component of the "best system of emission reduction . . . adequately demonstrated."

d. *Combination of all three building blocks.* The final BSER includes a combination of all three building blocks. For the reasons described below, and similar to each of the building blocks, the combination must be considered a "system of emission reduction." Moreover, as also discussed below, the combination qualifies as the "best" system that is "adequately demonstrated." The combination is technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it also performs well against the other BSER factors; and its components are well-established. The combination of the three building blocks will achieve greater CO_2 emission reductions at reasonable costs than possible combinations with fewer building blocks and will also perform better against other BSER factors. We therefore find the combination of all three building blocks to be the "best system of emission reduction . . . adequately demonstrated" for reducing CO_2 emissions at affected EGUs.

As already discussed, each of the individual building blocks generally performs well with respect to the BSER factors identified by the statute and the D.C. Circuit. (The exception, which we have pointed out above, is that building block 1, if implemented in isolation, would achieve an insufficient magnitude of emission reductions to be considered the BSER.) The

EPA expects that combinations of the building blocks would perform better than the individual building blocks. Beginning with the most obvious and important advantage, combinations of the building blocks will achieve greater emission reductions than the individual building blocks would in isolation, assuming that the building blocks are applied with the same stringency. Because fossil fuel-fired EGUs generally have higher variable costs than other EGUs, it will generally be fossil fuel-fired generation that is replaced when low-variable cost RE generation is increased. At the levels of stringency determined to be reasonable in this rule, opportunities to deploy building block 2 to replace higher-emitting generation and to deploy building block 3 to replace any emitting generation are not exhausted. Thus, as the system of emission reduction is expanded to include each of these building blocks, the emission reductions that will be achieved increase.

Because the stringency and timing of emission reductions achievable through use of each individual building block have been set based on what is achievable at reasonable cost rather than the maximum achievable amount, the stringency of the combination of building blocks is also reasonable, and the combination provides headroom and additional flexibility for states in setting standards of performance and for sources in complying with those standards to choose among multiple means of reducing emissions.

With respect to the quantity of emission reductions expected to be achieved from building block 1 in particular, the BSER encompassing all three building blocks is a substantial improvement over building block 1 in isolation. As noted earlier, the EPA is concerned that implementation of building block 1 in isolation not only would achieve insufficient emission reductions assuming generation levels from affected steam EGUs were held constant, but also has the potential to result in a "rebound effect." The nature of the potential rebound effect is that by causing affected steam EGUs to improve their heat rates and thereby lower their variable operating costs, building block 1 if implemented in isolation would make those EGUs more competitive relative to other, lower-emitting fossil fuel-fired EGUs, possibly resulting in increased generation and higher emissions from the affected steam EGUs in spite of their lower emission rates. Combining building block 1 with the other building blocks addresses this concern by ensuring that owner/operators of affected steam EGUs as a group would have appropriate incentives not only to improve the steam EGUs' efficiency but also to reduce generation from those EGUs consistent with replacement of generation by low- or zero-emitting EGUs. While combining building block 1 with either building block 2 or 3 should address this concern, the combination of all three building blocks addresses it more effectively by strengthening the incentives to reduce generation from affected steam EGUs.

The combination of all three building blocks is also of reasonable cost, for a number of independent reasons described below. The emission reductions associated with the BSER determined in this rule are significant, necessary, and achievable. As discussed in section V.A.1. above, the Administrator must take cost into account when determining that the measures constituting the BSER are adequately demonstrated, and the Administrator has done so here. Below, we summarize information on the cost of the building block measures and discuss the several independent reasons for the Administrator's determination that the costs of the building block 1, 2, and 3 measures, alone or in combination, are reasonable. In considering whether these costs are reasonable, the EPA considered the costs in light of both the observed and projected effects of GHGs in the atmosphere, their effect on climate, and the public health and welfare risks and impacts associated with such climate change, as described in Section II.A. The EPA focused on public health and welfare impacts within the U.S., but the impacts in other world regions strengthen the case for action because impacts in other world regions can in turn adversely affect the U.S. or its citizens. In looking at whether costs were reasonable, the EPA also considered that EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., as more fully set forth in section II.B.

As described in sections V.C. through V.E. and the GHG Mitigation Measures TSD, the EPA has determined that the cost of each of the three building blocks is reasonable. In summary, these cost estimates are \$23 per ton of CO_2 reductions for building block 1, \$24 per ton for building block 2, and \$37 per ton for building block 3. The EPA estimates that, together, the three building blocks are able to achieve CO_2 reductions at an average cost of \$30 per ton, which the EPA likewise has determined is reasonable. The \$30 per ton estimate is an average of the estimates for each building block, weighted by the total estimated cumulative CO_2 reductions for each of these building blocks over the 2022–2030 period.

While it is possible to weight each building block by other amounts, the EPA believes that weighting by cumulative CO_2 reductions best reflects the average cost of total reduction potential across the three building blocks. The EPA considers each of these cost levels reasonable for purposes of the BSER established for this rule.

The EPA views the weighted average cost estimate as a conservatively high estimate of the cost of deploying all three building blocks simultaneously. The simultaneous application of all three building blocks produces interactive dynamics, some of which could increase the cost and some of which could decrease the cost represented in the individual building blocks. For example, one dynamic that would tend to raise costs (and whose omission would therefore make the weighted average understate costs) is that the emission reduction measures associated with building blocks 2 and 3 both prioritize the replacement of higher-cost generation (from affected steam EGUs in the case of building block 2 and from all affected EGUs in the case of building block 3). The EPA recognizes that the increased magnitude of generation replacement when building blocks 2 and 3 are implemented together necessitates that some of the generation replacement will occur at more efficient affected EGUs, at a relatively higher cost; however, this is a consequence of the greater emission reductions that can be achieved by combining building blocks, not an indication that any individual building block has become more expensive because of the combined deployment.

Also, the EPA recognizes that when building block 1 is combined with the other building blocks, the combination has the potential to raise the cost of the portion of the overall emission reductions achievable through heat rate improvements relative to the cost of those same reductions if building block 1 were implemented in isolation (assuming for purposes of this discussion that the rebound effect is not an issue and that the affected steam EGUs would in fact reduce their emissions if building block 1 were implemented in isolation).[422] However, we believe that the cost of emission reductions achieved through heat rate improvements in the context of a three-building block BSER will remain reasonable for two reasons. First, as discussed in section V.C. below, even when conservatively high investment costs are assumed, the cost of CO_2 emission reductions achievable through heat rate improvements is low enough that the cost per ton of CO_2 emission reductions will remain reasonable even if that cost is substantially increased. Second, although under a BSER encompassing all three building blocks the volume of coal-fired generation will decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs will decrease their generation slightly or not at all while others will decrease their generation by larger percentages or

[422] If an EGU produces less generation output, then an improvement in that EGU's heat rate and rate of CO_2 emissions per unit of generation produces a smaller reduction in CO_2 emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU's generation output, then the cost per unit of CO_2 emission reduction will be higher when the EGU's generation output is lower. Commenters have also stated that operating at lower capacity factors may cause units to experience deterioration in heat rates.

cease operations altogether. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there will be a tendency for such investments to be concentrated in EGUs whose generation output is expected to decrease the least. This enlightened bias in spending on heat rate improvements—that is, focusing investments on EGUs where such improvements will have the largest impacts and produce the highest returns, given consideration of projected changes in dispatch patterns—will tend to mitigate any deterioration in the cost of CO_2 emission reductions achievable through heat rate improvements.

In contrast with those prior examples, combining the building blocks also produces interactive dynamics that significantly reduce the cost for CO_2 reductions represented in the individual building blocks (and whose omission would therefore make the weighted average overstate costs). Foremost among these dynamics is the stabilization of wholesale power prices. When assessed individually, building blocks 2 and 3 have opposite impacts on wholesale power prices, although in each case, the direction of the wholesale power price impact corresponds to an increasing cost of that building block in isolation. For example, building block 2 promotes more utilization of existing NGCC capacity, which (assessed on its own) would increase natural gas consumption and therefore price, in turn raising wholesale power prices (which are often determined by gas-fired generators as the power supplier on the margin); this dynamic puts upward pressure on the cost of achieving CO_2 reductions through shifting generation from steam EGUs to NGCC units.[423] Meanwhile, building block 3 increases RE deployment; because RE generators have very little variable cost, an increase in RE generation replaces other supply with higher variable cost, which would yield lower wholesale power prices. Lower wholesale power prices would make further RE deployment less competitive against generation from existing emitting sources; while this dynamic would generally reduce electricity prices to consumers, it also puts upward pressure on the cost of achieving CO_2 reductions through increased RE deployment.[424] Applying building blocks 2 and 3 together produces significantly more CO_2 reductions at a relatively lower cost because the countervailing nature of these wholesale power price dynamics mitigates the primary cost drivers for each building block.[425]

The EPA believes the dynamics tending to cause the weighted average above to overstate costs of the combination of building blocks are greater than the

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[423] The EPA's cost-effectiveness estimate of $24 per ton for building block 2 reflects these market dynamics.

[424] The EPA's cost-effectiveness estimate of $37 per ton for building block 3 reflects these market dynamics.

[425] Notwithstanding the interactive dynamics that improve the cost effectiveness of emission reductions when building blocks 2 and 3 are implemented together, we also consider each of these building blocks to be independently of reasonable cost, so that either building block 2 or 3 alone, or combinations of the building blocks that include either but not both of these two building blocks, could be the BSER if a court were to strike down the other building block, as discussed in section V.A.7. below. (We also note in section V.A.7. that a combination of building blocks 2 and 3 without building block 1 could be the BSER if a court were to strike down building block 1.)

dynamics tending to cause costs to be understated, and that the weighted average costs are therefore conservatively high. Analysis performed by the EPA at an earlier stage of the rulemaking supports this conclusion. At proposal, the EPA evaluated the cost of increasing NGCC utilization (building block 2) and deploying incremental RE generation (building block 3) independently, as well as the cost of simultaneously increasing NGCC utilization and incremental RE generation. The average cost (in dollars per ton of CO_2 reduced) was less for the combined building block scenario, showing that the net outcome of the interactivity effects described above is a reduction in cost per ton when compared to cost estimates that do not incorporate this interactivity.[426]

A final reason why the EPA considers the weighted-average cost above conservatively high is that simply combining the building blocks at their full individual stringencies overstates the stringency of the BSER. As discussed in section V.A.3.f and section VI, the BSER reflects the combined degree of emission limitation achieved through application of the building blocks in the least stringent region. By definition, in the other two regions, the BSER is less stringent than the simple combination of the three building blocks whose stringency is represented in the weighted-average cost above.

The cost estimates for each of the three building blocks cited above—$23, $24, and $37 per ton of CO_2

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[426] Specifically, at proposal the EPA quantified the average cost, in dollar per ton of CO_2 reduced, of building blocks 1, 2, and 3 ($22.5 per ton) to be less than the cost of either building block 2 ($28.9 per ton) or building block 3 ($23.4 per ton) alone.

reductions from building blocks 1, 2, and 3, respectively—are each conservatively high for the reasons discussed in section V.C., V.D., and V.E. below. Likewise, the \$30 per ton weighted-average cost of all three building blocks is a conservatively high estimate of the cost of the combination of the three individual building block costs, as described above. While conservatively high, and especially so in the case of the \$30 per ton weighted-average cost, these estimates fall well within the range of costs that are reasonable for the BSER for this rule.

In assessing cost reasonableness for the BSER determination for this rule, the EPA has compared the estimated costs discussed above to two types of cost benchmark. The first type of benchmark comprises costs that affected EGUs incur to reduce other air pollutants, such as SO_2 and NO_X. In order to address various environmental requirements, many coal-fired EGUs have been required to decide between either shutting down or installing and operating flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions. The fact that many of these EGUs have chosen scrubbers in preference to shutting down is evidence that scrubber costs are reasonable, and we believe that the cost of these controls can reasonably serve as a cost benchmark for comparison to the costs of this rule. We estimate that for a 300–700 MW coal-fired steam EGU with a heat rate of 10,000 Btu per kWh and operating at a 70 percent utilization rate, the annualized costs of installing and operating a wet scrubber are approximately \$14 to \$18 per MWh and the annualized costs of installing and operating a dry scrubber are approximately \$13 to \$16 per MWh.[427]

In comparison, we estimate that for a coal-fired steam EGU with a heat rate of 10,000 Btu per kWh, assuming the conservatively high cost of \$30 per ton of CO_2 removed through the combination of all three building blocks, the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for steam EGUs of 1,305 lbs. CO_2 per MWh would be equivalent to approximately \$11 per MWh. The comparable costs for achieving the required emission performance rate for steam EGUs through use of the individual building blocks range from \$8 to \$14 per MWh. For an NGCC unit with a heat rate of 7,800 Btu per kWh, assuming a conservatively high cost of \$37 per ton of CO_2 removed through the use of building block 3,[428] the cost of reducing CO_2 emissions by the amount required to achieve the uniform CO_2 emission performance rate for NGCC units of 771 lbs. CO_2 per MWh would be equivalent to approximately \$3 per MWh.[429] These estimated CO_2 reduction costs of \$3 to \$14 per MWh to achieve the CO_2 emission performance rates are either less than the ranges of \$14 to \$18 and \$13 to \$16 per MWh to install and operate a wet or dry scrubber, or

[427] For details of these computations, see the memorandum "Comparison of building block costs to FGD costs" available in the docket.

[428] The comparison for an NGCC unit considers only building block 3 because building blocks 1 and 2 do not apply to NGCC units.

[429] For details of these computations, see the memorandum "Comparison of building block costs to FGD costs" available in the docket.

in the case of CO_2 emission reductions at a steam unit achieved through building block 3, near the low end of the ranges of scrubber costs. This comparison demonstrates that the costs associated with the BSER in this rule are reasonable compared to the costs that affected EGUs commonly face to comply with other environmental requirements.

The second type of benchmark comprises CO_2 prices that owners of affected EGUs use for planning purposes in their IRPs. Utilities subject to requirements to prepare IRPs commonly include assumptions regarding future environmental regulations that may become effective during the time horizon covered by the IRP, and assumptions regarding CO_2 regulations are often represented in the form of assumed prices per ton of CO_2 emitted or reduced. A survey of the CO_2 price assumptions from 46 recent IRPs shows a range of CO_2 prices in the IRPs' reference cases of \$0 to \$30 per ton, and a range of CO_2 prices in the IRPs' high cases from \$0 to \$110 per ton.[430] In comparison, the conservatively high, weighted-average cost of \$30 per ton removed described above is at the high end of the range of reference case assumptions but at the low end of the range of the high case assumptions. The costs of the individual building blocks are likewise well within the range of the high case assumptions, and either at or slightly above the high end of the reference case assumptions. This comparison demonstrates that the

[430] *See* Synapse Energy Economics Inc., 2015 Carbon Dioxide Price Forecast (March 3, 2015) at 25–28, *available at http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf*.

costs associated with the BSER in this rule are reasonable compared to the expectations of the industry for the potential costs of CO_2 regulation.

In addition to comparison to these benchmarks, there is a third independent way in which EPA has considered cost. In light of the severity of the observed and projected climate change effects on the U.S., U.S. interests, and U.S. citizens, combined with EGUs' large contribution to U.S. GHG emissions, the costs of the BSER measures are reasonable when compared to other potential control measures for this sector available under section 111. Given EGUs' large contribution to U.S. GHG emissions, any attempt to address the serious public health and environmental threat of climate change must necessarily include significant emission reductions from this sector. The agency would therefore consider even relatively high costs—which these are not—to be reasonable. Imposing only the lower cost reduction measures in building block 1 would not achieve sufficient reductions given the scope of the problem and EGUs' contribution to it. While the EPA also considered measures such as CCS retrofits for all fossil-fired EGUs or co-firing at all steam units, the EPA determined that these costs were too high when considered on a sector-wide basis. Furthermore, the EPA has not identified other measures available under section 111 that are less costly and would achieve emission reductions that are commensurate with the scope of the problem and EGUs' contribution to it. Thus, the EPA determined that the costs of the measures in building blocks 1, 2 and 3, individually or in combination, are reasonable because they achieve an appropriate balance between cost and amount of reductions given the other potential control measures under section 111.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules.[431] While benefit-cost analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (*i.e.*, a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air Act, and is not using such a test here.[432] Nonetheless, the EPA observes that the costs of the building block 1, 2 and 3 measures, both individually and combined as discussed in this section above, are less than the central estimates of the social cost of carbon. Developed by an interagency workgroup, the social cost of carbon (SC-CO_2) is an estimate of the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year.[433] It is typically used

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[431] The EPA's regulatory impact analysis for this rule, which appropriately includes a representation of the flexibility available under the rule to comply using a combination of BSER and non-BSER measures (such as demand-side energy efficiency) is discussed in section XI of the preamble.

[432] See memo entitled "Consideration of Costs and Benefits Under the Clean Air Act" available in the docket.

[433] Estimates are 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)*, 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,

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).[434] The central values for the SC-CO_2 range from $40 per short ton in 2020 to $48 per short ton in 2030.[435] The weighted-average cost estimate of $30 per ton is well below this range.

Finally, the EPA notes that the combination of all three building blocks would perform consistently with the individual building blocks with respect to non-air energy and environmental impacts. There is no reason to expect an adverse non-air environmental or energy impact from deployment of the combination of

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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 (May 2013, Revised July 2015). Available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf*> Accessed 7/11/2015.

[434] The SC-CO_2 estimates do not include all important damages because of current modeling and data limitations. The 2014 IPCC report observed that SC-CO_2 estimates omit various impacts that would likely increase damages. *See* IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability*. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge. *https://www.ipcc.ch/report/ar5/wg2/*.

[435] The 2010 and 2013 TSDs present SC-CO_2 in 2007$ per metric ton. The unrounded estimates from the current TSD were adjusted to (1) 2011$ using GDP Implicit Price Deflator (1.061374), *http://www.bea.gov/iTable/index_nipa.cfm* and (2) short tons using the conversion factor of 0.90718474 metric tons in a short ton. These estimates were rounded to two significant digits.

the three building blocks, whether considered on a source-by-source basis, on a sector-wide or national basis, or both. In fact, the combination of the building blocks, like the building blocks individually, as discussed above, would be expected to produce non-air environmental co-benefits in the form of reduced water usage and solid waste production (and, in addition to these non-air environmental co-benefits, would also be expected to reduce emissions of non-CO_2 air pollutants such as SO_2, NO_X, and mercury). Likewise, with respect to technological innovation, which we consider only in the alternative, the building blocks in combination would have the same positive effects that they would have if implemented independently.

e. *Other combinations of the building blocks*. The EPA has considered whether other combinations of the building blocks, such as a combination of building blocks 1 and 2 or a combination of building blocks 1 and 3, could be the BSER. We believe that any such combination is technically feasible and would be a "system of emission reduction" capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost. As with the combination of three building blocks discussed above, any combination of building blocks would achieve greater emission reductions than the individual building blocks encompassed in that combination would achieve if implemented in isolation. Further, the cost of any combination would be driven principally by the combined stringency and would remain reasonable in aggregate, such that the conclusions on cost reasonableness discussed in section V.A.4.d. would continue to apply. We have already noted our determination that building block 1 in isolation is not the BSER because it would not produce a sufficient quantity of emission reductions. A combination of building block 1 with one of the other building blocks would produce greater emission reductions and would not be subject to this concern. Any combination of building blocks including building block 1 and at least one other building block would also address the concern about potential "rebound effect," discussed above, that could occur if building block 1 were implemented in isolation. Finally, there is no reason to expect any combination of the building blocks to have adverse non-air energy or environmental impacts, and the implications for technological innovation, which we consider only in the alternative, would likewise be positive for any combination of the building blocks because those implications are positive for the individual building blocks and there is no reason to expect negative interaction from a combination of building blocks.

For these reasons, any combination of the building blocks (but not a BSER comprising building block 1 in isolation) could be the BSER if it were not for the fact that a BSER comprising all three of the building blocks will achieve greater emission reductions at a reasonable cost and is therefore "better." As discussed below in section V.A.7., we intend for the individual building blocks to be severable, such that if a court were to deem building block 2 or 3 defective, but not both, the BSER would comprise the remaining building blocks.

f. *Achievability of emission limits.* As noted, based on the BSER, the EPA has established a source subcategory-specific emission performance rate for fossil steam units and one for NGCC units. As discussed in section V.A.1.c., for new sources, standards of performance must be "achievable" under CAA section 111(a)(1), and the D.C. Circuit has identified criteria for achievability.[436] In this rule, the EPA is taking the approach that while the states are not required to adopt those source subcategory-specific emission performance rates as the standards of performance for their affected EGUs, those rates must be achievable by the steam generator and NGCC subcategories, respectively. In addition, the EPA is assuming that the achievability criteria in the case law for new sources apply to existing sources under section 111(d). For the reasons discussed next, for this rule, the source subcategory-specific emission performance rates are achievable in accordance with those criteria in the case law.

As noted, the building blocks include several features that assure that affected EGUs may implement them. The building blocks may be implemented through a range of methods, including through the purchase of ERCs and emission trading. In addition, the building blocks incorporate "headroom." Moreover, the source subcategory-specific emission performance rates apply on an annual or longer basis, so that short-term issues need not jeopardize compliance. In addition, we quantify the emission performance rates based on the degree of emission limitation achievable by affected EGUs in

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[436] *See Essex Chem. Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied*, 416 U.S. 969 (1974); *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980); *Sierra Club* v. *Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA*, 627 F.2d 416 (D.C. Cir. 1980).

the region where application of the combined building blocks results in the least stringent emission rate. Because the means to implement the building blocks are widely available and because of the just-noted flexibilities and approaches to the emission performance rates, all types of affected steam generating units, operating throughout the lower-48 states and under all types of regulatory regimes, are able to implement building blocks 1, 2 and 3 and thereby achieve the emission performance rate for fossil steam units, and all types of NGCC units operating in all states under all types of regulatory requirements are able to implement building block 3 and thereby achieve the emission performance rate for NGCC units.[437]

Commenters have raised questions about whether particular circumstances could arise, such as the sudden loss of certain generation assets, that would cause the implementation of the building blocks to cause reliability problems, and have cautioned that these circumstances could preclude implementation of the building blocks and thus achievement of the emission performance rates. Commenters have also raised concerns about whether affected EGUs with limited remaining useful lives can implement the building blocks and achieve the emission performance rates. We address those concerns in section VIII, where we authorize state plans to include a reliability mechanism and discuss affected EGUs with limited remaining useful lives. Accordingly, we conclude that

[437] We discuss the ability of affected EGUs to implement the building blocks in more detail in sections V.C., V.D., and V.E. and the accompanying support documents.

the source subcategory-specific emission performance standards are achievable in accordance with the case law.

5. Actions Under the BSER That Sources Can Take To Achieve Standards of Performance

Based on the determination of the BSER described above, the EPA has identified a performance rate of 1305 lbs. per net MWh for affected steam EGUs and a performance rate of 771 lbs. per net MWh for affected stationary combustion turbines. The computations of these performance rates and the determinations of state goals reflecting these rates are described in sections VI and VII of the preamble, respectively.

Under section 111(d), states determine the standards of performance for individual sources. The EPA is authorizing states to express the standards of performance applicable to affected EGUs as either emission rate-based limits or mass-based limits. As described above, the sets of actions that sources can take to comply with these standards implement or apply the BSER and, in that sense, may be understood as part of the BSER.

A source to which a state applies an emission rate-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are components of the BSER, again, in the sense that they implement or apply it:

- Reducing its heat rate (building block 1).
- Directly investing in, or purchasing ERCs created as a result of, incremental generation from existing NGCC units (building block 2).

- Directly investing in, or purchasing ERCs created as a result of, generation from new or uprated RE generators (building block 3).

- Reducing its utilization, coupled with direct investment in or purchase of ERCs representing building blocks 2 and 3 as indicated above.

- Investing in surplus emission rate reductions at other affected EGUs through the purchase or other acquisition of rate-based emission credits.

A source to which a state applies a mass-based limit can achieve the limit through a combination of the following set of measures (to the extent allowed by the state plan), all of which are likewise components of the BSER:

- Reducing its heat rate (building block 1).

- Reducing its utilization and allowing its generation to be replaced or avoided through the routine operation of industry reliability planning mechanisms and market incentives.

- Investing in surplus emission reductions at other affected EGUs through the purchase or other acquisition of mass-based emission allowances.

The EPA has determined appropriate CO_2 emission performance rates for each of the two source subcategories as a whole achievable through application of the building blocks. The wide ranges of measures included in the BSER and available to individual sources as indicated above provide assurance that the source category as a whole can achieve standards of performance consistent with those emissions standards using components of the BSER, whether states choose to establish emission rate-based limits or mass-based limits. The wide ranges of measures included in the BSER also provide assurance that each individual affected EGU could achieve the standard of performance its state establishes for it using components of the BSER. Of course, sources may also employ measures not included in the BSER, to the extent allowed under the applicable state plan.

In the remainder of this subsection, we discuss further how affected EGUs can use each of the measures listed above to achieve emission rate-based forms of performance standards and mass-based forms of performance standards, indicating that all types of owner/operators of affected EGUs—*i.e.*, vertically integrated utilities and merchant generators; investor-owned, government-owned, and customer-owned (cooperative) utilities; and owner/operators of large, small, and single-unit fleets of generating units—have the ability to implement each of the building blocks in some way. In the following subsection we discuss the use of measures not in the BSER that can help sources achieve the standards of performance.

a. *Use of BSER measures to achieve an emission rate-based standard.* Under an emission-rate based form of performance standards, compliance is nominally determined through a comparison of the affected EGU's emission rate to the emission rate standard. The emissions-reducing impact of BSER measures that reduce CO_2 emissions through reductions in the quantity of generation rather than through reductions in the amount of CO_2 emitted per unit of generation would not be reflected in an affected EGU's emission rate computed solely based on measured stack emissions and measured electricity generation but can readily be reflected in an emission rate computation by averaging ERCs acquired by the affected EGU into the rate computation.

In section VIII.K, we discuss the processes for issuance and use of ERCs that can be included in the emission rate computations that affected EGUs perform to demonstrate compliance with an emission rate standard. This ERC mechanism is analogous to the approach the EPA has used to reflect building blocks 2 and 3 in the uniform emission rates representing the BSER, as discussed in section VI below. As summarized below and as discussed in greater detail in section VIII.K, the existence of a clearly feasible path for usage of ERCs ensures that emission reductions achievable through implementation of the measures in building blocks 2 and 3 are available to assist all affected EGUs in achieving compliance with standards of performance based on the BSER.

(1) *Building block 1.*

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 emission rate. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) *Building block 2.*

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of incremental generation from an existing NGCC unit. As permitted under the EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the NGCC unit, a bilateral transaction with the owner/ operator of the NGCC unit, or a transaction for ERCs through an intermediary, which could but need not involve an organized market.[438] As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of NGCC facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon incremental electricity generation by an existing NGCC unit. Those criteria generally concern ensuring that the physical basis for the ERC—*i.e.*, qualifying generation by an existing NGCC unit and the NGCC unit CO_2 emissions associated with that qualifying

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[438] Each of these methods of implementing building block 2 meets the criteria for the BSER in that (i) as we discuss in section V.D. and supporting documents, each of these methods is adequately demonstrated; (ii) the costs of each of these methods on a source-by-source basis are reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

generation—is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting. In the case of ERCs related to building block 2, the monitoring criteria would generally be satisfied by standard 40 CFR part 75 monitoring.

The owner/operator of an affected steam EGU would use the ERCs it has acquired for compliance—whether acquired through ownership of NGCC capacity, a bilateral transaction, or an intermediated transaction—by adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(3) *Building block 3.*

The owner/operator of an affected EGU can average the EGU's emission rate with ERCs issued on the basis of generation from new (*i.e.*, post-2012) RE generating capacity, including both newly constructed capacity and new uprates to existing RE generating capacity. As permitted under the EGU's state's section 111(d) plan, the owner/operator of the affected EGU could accomplish this through either common ownership of the RE generating capacity, a bilateral transaction with the owner/operator of the RE generating capacity, or a transaction for ERCs through an intermediary, which could, but need not, involve an organized market.[439] As discussed earlier,

[439] As with building block 2, each of these methods of implementing building block 3 meets the criteria for the BSER in that (i) as we discuss in section V.E. and supporting documents, each of these methods is adequately demonstrated; (ii) the costs of each of these methods on a source-by-source basis are

based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of ERCs. While the opportunity to acquire ERCs through common ownership of RE generating facilities might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for ERCs just as they can engage in transactions for other kinds of goods and services.

In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon generation from new RE generating capacity. Those criteria generally concern assuring that the physical basis for the ERC—*i.e.*, generation by qualifying new RE capacity—is adequately monitored and that there is an adequate administrative process for tracking credits to avoid double-counting.[440]

As with building block 2, the owner/operator of an affected EGU would use the ERCs it has acquired for compliance—whether acquired through ownership of qualifying RE generating capacity, a bilateral transaction, or an intermediated transaction—by

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reasonable, as discussed above; and (iii) none of these methods causes adverse energy impacts or non-quality environmental impacts.

[440] The possible use of types of RE generating capacity that are not included in the BSER is discussed in section V.A.6. and section VIII of the preamble.

adding the ERCs to its measured net generation when computing its CO_2 emission rate for purposes of demonstrating compliance with its emission rate-based standard of performance.

(4) *Reduced generation.*

The owner/operator of an affected EGU can reduce the unit's generation and reflect that reduction in the form of a lower emission rate provided that the owner/operator also acquires some amount of ERCs to use in computing the unit's emission rate for purposes of demonstrating compliance. As permitted under the EGU's state's section 111(d) plan, the ERCs could be acquired through investment in incremental generation from existing NGCC capacity, generation from new RE generating capacity, or purchase from an entity with surplus ERCs. If the owner/operator does not average any ERCs into the unit's emission rate, reducing the unit's own generation will proportionately reduce both the numerator and denominator of the fraction and therefore will not affect the computed emission rate (unless the unit retires, reducing its emission rate to zero). However, if the owner/operator does average ERCs into the unit's emission rate, then a proportional reduction in both the numerator and the portion of the denominator representing the unit's measured generation will amplify the effect of the acquired ERCs in the computation, with the result that the more the unit reduces its generation, the fewer ERCs will be needed to reach a given emission rate-based standard of performance. All owner/operators have the ability to reduce generation, and as discussed above all also would be capable of acquiring ERCs, so all would be capable of reflecting reduced utilization in their emission rates for purposes of demonstrating compliance.

(5) *Emissions trading approaches.*

To the extent allowed under standards of performance that incorporate emissions trading or otherwise through the relevant section 111(d) plans, the owner/operator of an affected EGU can acquire tradable rate-based emission credits representing an investment in surplus emission rate reductions not needed by another affected EGU and can average those credits into its own emission rate for purposes of demonstrating compliance with its rate-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below. As we have repeatedly noted, based on our reading of the comment record and the discussions that occurred during the outreach process, it is reasonable to presume that such authorization will be forthcoming from states that submit plans establishing rate-based standards of performance for their affected EGUs.

Under a rate-based emissions trading approach, credits are initially created and issued according to processes defined in the state plan. After credits are initially issued, the owner/operator of an affected EGU needing additional credits can acquire credits through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire credits in a transaction through an intermediary, which could, but need not, involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans and/or standards of performance established thereunder authorize emissions trading. While the opportunity to acquire credits through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/operators would have the ability to engage in bilateral or intermediated purchase transactions for credits just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of rate-based emission credits in a state plan (using ERCs issued on the basis of investments in building blocks 2 and 3 and potentially other measures as the credits) are provided in section VIII.K.

b. *Use of BSER measures to achieve a mass-based standard*. Under a mass-based form of the standard, compliance is determined through a comparison of the affected EGU's monitored mass emissions to a mass-based emission limit. Although a state could choose to impose specific mass-based limits that each EGU would be required to meet on a physical basis, in past instances where mass-based limits have been established for large numbers of sources it has been typical for the limit on each affected EGU to be structured as a requirement to periodically surrender a quantity of emission allowances equal to the source's monitored mass emissions. The EPA believes that section 111(d) encompasses the flexibility for plans to impose mass-based standards in the typical manner where the standard of performance for each affected

EGU consists of a requirement to surrender emission allowances rather than a requirement to physically comply with a unit-specific emissions cap.

Measurements of mass emissions at a given affected EGU capture reductions in the EGU's emissions arising from both reductions in generation and reductions in the emission rate per MWh. Accordingly, under a mass-based standard there is no need to provide a mechanism such as the ERC mechanism described above in order to properly account for emission reductions attributable to particular types of BSER measures. The relative simplicity of the mechanics of monitoring and determining compliance are significant advantages inherent in the use of mass-based standards rather than emission rate-based standards.

(1) *Building block 1.*

The owner/operator of an affected steam EGU can take steps to reduce the unit's heat rate, thereby lowering the unit's CO_2 mass emissions. Examples of actions in this category are included in section V.C. below and in the GHG Mitigation Measures TSD for the CPP Final Rule. Any type of owner/operator can take advantage of this measure.

(2) *Reduced generation.*

The owner/operator of an affected EGU can reduce its generation, thereby lowering the unit's CO_2 mass emissions. Any type of owner/operator can take advantage of this measure. Although some action or combination of actions to increase lower-carbon generation or reduce electricity demand somewhere in the interconnected electricity system of which the affected EGU is a part will be required to enable electricity supply and demand to remain in balance, the affected EGU does not need to monitor or track those actions in order to use its reduction in generation to help achieve compliance with the mass-based standard. Instead, multiple participants in the interconnected electricity system will act to ensure that supply and demand remain in balance, subject to the complex and constantly changing set of constraints on operation of the system, just as those participants have routinely done for years.

Of course, if the owner/operator of the affected EGU wishes to play a direct role in driving the increase in lower-carbon generation or demand-side EE required to offset a reduction in the affected EGU's generation, the owner/operator may do so as part of whatever role it happens to play as a participant in the interconnected electricity system. However, the owner/operator will achieve the benefit that reduction in generation brings toward compliance with the mass-based standard whether it takes those additional actions itself or instead allows other participants in the interconnected electricity system to play that role.

(3) *Emissions trading approaches.*

To the extent allowed under the relevant section 111(d) plans—as the record indicates that it is reasonable to expect it will be—the owner/operator of an affected EGU can acquire tradable mass-based emission allowances representing investment in surplus emission reductions not needed by another affected EGU and can aggregate those allowances with any other allowances it already holds for purposes of demonstrating compliance with its mass-based standard of performance. The approach would have to be authorized in the appropriate section 111(d) plan and would have to conform to the minimum conditions for such approaches described in section VIII below.

Under a mass-based emissions trading approach, the total number of allowances to be issued is defined in the state plan, and affected EGUs may obtain an initial quantity of allowances through an allocation or auction process. After that initial process, the owner/operator of an affected EGU needing additional allowances can acquire allowances through common ownership of another affected EGU or through a bilateral transaction with the other affected EGU, or the owner/operator of the affected EGU can acquire allowances in a transaction through an intermediary, which could but need not involve an organized market. As discussed earlier, based on observation of market behavior both inside and outside the electricity industry, we expect that intermediaries will seek opportunities to participate in such transactions and that organized markets are likely to develop as well if section 111(d) plans authorize the use of emissions trading. While the opportunity to acquire allowances through common ownership might not extend to owner/operators of single EGUs or small fleets, all owner/ operators would have the ability to engage in bilateral or intermediated purchase transactions for allowances just as they can engage in transactions for other kinds of goods and services.

Further details regarding the possible use of mass-based emission allowances in a state plan are provided in section VIII.J.

6. Use of Non-BSER Measures To Achieve Standards of Performance

In addition to the BSER-related measures that affected EGUs can use to achieve the standards of performance set in section 111(d) plans, there are a variety of non-BSER measures that could also be employed (to the extent permitted under a given plan). This final rule does not limit the measures that affected EGUs may use for achieving standards of performance to measures that are included in the BSER; thus, the existence of these non-BSER measures provides flexibility allowing the individual affected EGUs and the source category to achieve emission reductions consistent with application of the BSER at the levels of stringency reflected in this final rule even if one or more of the building blocks is not implemented to the degree that the EPA has determined to be reasonable for purposes of quantifying the BSER. In this way, non-BSER measures provide additional flexibility to states in establishing standards of performance for affected EGUs through section 111(d) plans and to individual affected EGUs for achieving those standards.

Any of the non-BSER measures described below would help the affected source category as a whole achieve emission limits consistent with the BSER. The non-BSER measures either reduce the amount of CO_2 emitted per MWh of generation from the set of affected EGUs or reduce the amount of generation, and therefore associated CO_2 emissions, from the set of affected EGUs. However, the manner in which the various non-BSER measures would help individual affected EGUs meet their individual standards of performance varies according to the type of measure and the type of standard of performance—*i.e.*, whether the standard is emission rate-based or mass-based.

In general, a non-BSER measure that reduces the amount of CO_2 emitted per MWh of generation at an affected EGU will reduce the amount of CO_2 emissions monitored at the EGU's stack (assuming the quantity of generation is held constant). Measures of this type can help the EGU meet either an emission rate-based or mass-based standard of performance.

Other non-BSER measures do not reduce an affected EGU's CO_2 emission rate but rather facilitate reductions in CO_2 emissions by reducing the amount of generation from affected EGUs. Under a mass-based standard, the collective reduction in emissions from the set of affected EGUs is reflected in the collective monitored emissions from the set of affected EGUs. An individual EGU that reduces its generation and emissions will be able to use the measure to help achieve its mass-based limit. Individual EGUs that do not reduce their generation and emissions will be able to use the measure, if the relevant section 111(d) plans provide for allowance trading, by purchasing emission allowances no longer needed by EGUs that have reduced their emissions.

Under an emission rate-based standard, non-BSER measures that reduce generation from affected EGUs but do not reduce an affected EGU's emission rate generally can facilitate compliance by serving as the basis for ERCs that affected EGUs can average into their emission rates for purposes of demonstrating compliance. Section VIII.K. includes a discussion of the issuance of ERCs based on various non-BSER measures. Affected EGUs could use such ERCs to the extent permitted by the relevant section 111(d) plans.

The remainder of this section discusses some specific types of non-BSER measures. The first set discussed includes measures that can reduce the amount of CO_2 emitted per MWh of generation, and the second set discussed includes measures that can reduce CO_2 emissions by reducing the amount of generation from affected EGUs. In some cases, considerations related to use of these measures for compliance are discussed below in section VIII on state plans. The EPA notes that this is not an exhaustive list of non-BSER measures that could be employed to reduce CO_2 emissions from affected EGUs, but merely a set of examples that illustrate the extent of the additional flexibility such measures provide to states and affected EGUs under the final rule.

a. *Non-BSER measures that reduce CO_2 emissions per MWh generated.* In the June 2014 proposal, the EPA discussed several potential measures that could reduce CO_2 emissions per MWh generated at affected EGUs but that were not proposed to be part of the BSER. The measures discussed included heat rate improvements at affected EGUs other than coal-fired steam EGUs; fuel switching from coal to natural gas at affected EGUs, either completely (conversion) or partially (co-firing); and carbon capture and storage by affected EGUs. One reason for not proposing to consider these measures to be part of the BSER was that they were more costly than the BSER measures. Another reason was that the emission reduction potential was limited compared to the potential available from the measures that were proposed to be included in the BSER. However, we also noted that circumstances could exist where these measures could be sufficiently attractive to deploy, and that the measures could be used to help affected EGUs achieve emission limits consistent with the BSER.

In the final rule, the EPA has reached determinations consistent with the proposal with respect to these measures: namely, that they do not merit inclusion in the BSER, but that they are capable of helping affected EGUs achieve compliance with standards of performance and are likely to be used for that purpose by some units. To the extent that they are selectively employed, they provide flexibility for the source category as a whole and for individual affected EGUs to achieve emission limits reflective of the BSER, as discussed above.

(1) *Heat rate improvement at affected EGUs other than coal-fired steam EGUs.*

Building block 1 reflects the opportunity to improve heat rate at coal-fired steam EGUs but not at other affected EGUs. As the EPA stated at proposal, the potential CO_2 reductions available from heat rate improvements at coal-fired steam EGUs are much larger than the potential CO_2 reductions available from heat rate improvements at other types of EGUs, and comments offered no persuasive basis for reaching a different conclusion. Nevertheless, we recognize that there may be instances where an owner/operator finds heat rate improvement to be an attractive option at a particular non-coal-fired affected EGU, and nothing in the rule prevents the owner/operator from implementing such a measure and using it to help achieve a standard of performance.

(2) *Carbon capture and storage at affected EGUs.*

Another approach for reducing CO_2 emissions per MWh of generation from affected EGUs is the application of carbon capture and storage (CCS) technology. Consistent with the June 2014 proposal, we are determining that use of full or partial CCS technology should not be part of the BSER for existing EGUs because it would be more expensive than the measures determined to be part of the BSER, particularly if applied broadly to the overall source category. At the same time, we note that retrofit of CCS technology may be a viable option at some individual facilities, particularly where the captured CO_2 can be used for enhanced oil recovery (EOR). For example, construction of one CCS retrofit application with EOR has already been completed at a unit at the Boundary Dam plant in Canada, and construction of another CCS retrofit application with EOR is underway at the W.A. Parish plant in Texas. We expect the costs of CCS to decline as implementation experience increases. CO_2 emission rate reductions achieved through retrofit of CCS technology would be available to help affected EGUs achieve emission limits consistent with the BSER. State plan considerations related to CCS are discussed in section VIII.I.2.a.

(3) *Fuel switching to natural gas at affected EGUs.*

In the proposal we discussed the opportunity to reduce CO_2 emissions at an individual affected EGU by switching fuels at the EGU, particularly by switching from coal to natural gas. Most coal-fired EGUs could be modified to burn natural gas instead, and the potential CO_2 emission reductions from this measure are large—approximately 40 percent in the case of conversion from 100 percent coal to 100 percent natural gas, and proportionately smaller for partial co-firing of coal with natural gas. The primary reason for not considering this measure part of the BSER, both at proposal and in this final rule, is that it is more expensive than the BSER measures. In particular, combusting natural gas in a steam EGU is less efficient and generally more costly than combusting natural gas in an NGCC unit. For the category as a whole, CO_2 emissions can be achieved far more cheaply by combusting additional natural gas in currently underutilized NGCC capacity and reducing generation from coal-fired steam EGUs (building block 2) than by combusting natural gas instead of coal in steam EGUs.

Some owner/operators are already converting some affected EGUs from coal to natural gas, and it is apparent that the measure can be attractive compared to alternatives in certain circumstances, such as when a unit must meet tighter unit-specific limits on emissions of non-GHG pollutants, the options for meeting those emission limits are costly, and retirement of the unit would necessitate transmission upgrades that are costly or cannot be completed quickly. CO_2 emission reductions achieved in these situations are available to help achieve emission limits consistent with the BSER.

(4) *Fuel switching to biomass at affected EGUs.*

Some affected EGUs may seek to co-fire qualified biomass with fossil fuels. 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. As with the other non-BSER measures discussed in this section, the EPA expects that use of biomass may be economically attractive for certain individual sources even though on a broader scale it would likely be more expensive or less achievable than the measures determined to be part of the BSER. Section VIII.I.2.c describes the process and considerations for states proposing to use different kinds of biomass in state plans.

(5) *Waste heat-to-energy conversion at affected EGUs.*

Certain affected EGUs in urban areas or located near industrial or commercial facilities with needs for thermal energy may be able add new equipment to capture some of the waste heat from their electricity generation processes and use it to create useful thermal output, thereby engaging in combined heat and power (CHP) production. While the set of affected EGUs in locations making this measure feasible may be limited, where feasible the potential CO_2 emission rate improvements can be substantial: Depending on the process used, the efficiency with which fuel is converted to useful energy can be increased by 25 percent or more. The final rule allows an owner/operator applying CHP technology to an affected EGU to account for the increased efficiency by counting the useful thermal output as additional MWh of generation, thereby lowering the unit's computed emission rate and assisting with achievement of an emission rate-based standard of performance. (The EPA notes that unless the unit also reduced its fuel usage, the addition of the capability to capture waste heat and produce useful thermal output would not reduce the unit's mass emissions and therefore would not directly help the unit achieve a mass-based standard of performance.[441])

b. *Non-BSER measures that reduce CO_2 emissions by reducing fossil fuel-fired generation.*

A second group of non-BSER measures has the potential to reduce CO_2 emissions from affected EGUs by reducing the amount of generation from those EGUs. As discussed above, under a section 111(d) plan with mass-based standards of performance, no special action is required to enable measures of this nature to help the source category as a whole and individual affected EGUs achieve their emission limits, because the CO_2-reducing effects are captured in monitored stack emissions. However, under a section 111(d) plan with rate-based standards of performance, affected EGUs would need to acquire ERCs based on the non-BSER activities that could be averaged into their emission rate computations for purposes of determining compliance with their standards of performance.

(1) *Demand-side EE.*

One of the major approaches available for achieving CO_2 emission reductions from the utility power sector is demand-side EE. In the June 2014 proposal, the EPA identified demand-side EE as one of the four proposed building blocks for the BSER. We continue to believe that significant emission reductions can be achieved by the source category through use of such measures at reasonable costs. In fact, we believe that

[441] However, the EPA notes that a state could establish a mechanism for encouraging affected EGUs to apply CHP technology under a mass-based plan, for example, through awards of emission allowances to CHP projects.

the potential emission reductions from demand-side EE rival those from building blocks 2 and 3 in magnitude, and that demand-side EE is likely to represent an important component of some state plans, particularly in instances where a state prefers to develop a plan reflecting the state measures approach discussed in section VIII below. We also expect that many sources would be interested in including demand-side EE in their compliance strategies to the extent permitted, and we received comment that it should be permitted.

For the reasons discussed in section V.B.3.c.(8) below, the EPA has determined not to include demand-side EE in the BSER in this final rule. However, the final rule authorizes generation avoided through investments in demand-side EE to serve as the basis for issuance of ERCs when appropriate conditions are met. In section VIII.K below, the EPA sets out the minimum criteria that must be satisfied for generation and issuance of a valid ERC based upon implementation of new demand-side EE programs. Those criteria generally concern ensuring that the physical basis for the ERC—in this case, generation avoided through implementation of demand-side EE measures—is adequately evaluated, measured, and verified and that there is an adequate administrative process for tracking credits.

Through their authority over legal requirements such as building codes, states have the ability to drive certain types of demand-side EE measures that are beyond the reach of private-sector entities. The EPA recognizes that, by definition, this type of measure is beyond the ability of affected EGUs to invest in either directly or through bilateral arrangements. However, the final rule also authorizes generation avoided through such state policies to serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. The section 111(d) plan would need to include appropriate provisions for evaluating, measuring, and verifying the avoided MWh associated with the state policies, consistent with the criteria discussed in section VIII.K below.

(2) *New or uprated nuclear generating capacity.*

In the June 2014 proposal, the EPA included generation from the five nuclear units currently under construction as part of the proposed BSER. As discussed above in section V.A.3.c., upon consideration of comments, we have determined that generation from these units should not be part of the BSER. However, we continue to observe that the zero-emitting generation from these units would be expected to replace generation from affected EGUs and thereby reduce CO_2 emissions, and the continued commitment of the owner/operators to completion of the units is essential in order to realize that result. Accordingly, a section 111(d) plan may rely on ERCs issued on the basis of generation from these units and other new nuclear units. For the same reason, a plan may rely on ERCs issued on the basis of generation from uprates to the capacity of existing nuclear units. Requirements for state plan provisions intended to serve this purpose are discussed in section VIII.K.

(3) *Zero-emitting RE generating technologies not reflected in the BSER.*

The range of available zero-emitting RE generating technologies is broader than the range of RE technologies determined to be suitable for use in quantification of building block 3 as an element of the BSER. Examples of additional zero-emitting RE technologies not included in the BSER that could be used to achieve emission limits consistent with the BSER include offshore wind, distributed solar, and fuel cells. These technologies were not included in the range of RE technologies quantified for the BSER because they are generally more expensive than the measures that were included and the other measures in the BSER. However, these technologies are equally capable of replacing generation from affected EGUs and thereby reducing CO_2 emissions. Further, as with any technology, there are likely to be certain circumstances where the costs of these technologies are more attractive relative to alternatives, making the technologies likely to be deployed to some extent. Indeed, distributed solar is already being widely deployed in much of the U.S. and offshore wind, while still unusual in this country, has been extensively deployed in some other parts of the world. We expect innovation in RE generating technologies to continue, making such technologies even more attractive over time. A section 111(d) plan may rely on ERCs issued on the basis of generation from new and uprated installations of these technologies. The necessary state plan provisions are discussed in section VIII.K.

(4) *Non-zero-emitting RE generating technologies.*

Generation from new or expanded facilities that combust qualified biomass or biogenic portions of municipal solid waste (MSW) to produce electricity can also replace generation from affected EGUs and thereby control CO_2 levels in the atmosphere.[442] While the EPA believes it is reasonable to consider generation from these fuels and technologies to be forms of RE generation, the fact that they can produce stack emissions containing CO_2 means that a section 111(d) plan seeking to permit use of such generation to serve as the basis for issuance of ERCs must include appropriate consideration of feedstock characteristics and climate benefits. Specifically, 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 only be realized if biomass feedstocks are sourced responsibly and attributes of the carbon cycle related to the biomass feedstock are taken into account. Section VIII.I.2.c describes the process and considerations for states proposing to use biomass in state plans. Section VIII.K describes additional provisions related to ERCs.

(5) *Waste heat-to-electricity conversion at non-affected facilities.*

Industrial facilities that install new equipment to capture waste heat from an existing combustion process and then use the waste heat to generate electricity—a form of combined heat and power (CHP) production—can produce generation that replaces generation from affected EGUs and thereby reduces CO_2 emissions. A section 111(d) plan may rely on

[442] The EPA and many states have recognized the importance of integrated waste materials management strategies that emphasize a hierarchy of waste prevention and all other productive uses of waste materials to reduce the volume of disposed waste materials (see section VIII for more discussion of waste-to-energy strategies).

ERCs issued on the basis of generation of this nature provided that the facility does not generate and sell sufficient electricity to qualify as a new EGU for purposes of section 111(b) and is not covered under section 111(d) for another source category. More information is provided in section VIII.K.

(6) *Reduction in transmission and distribution line losses.*

Reductions of electricity line losses incurred from the transmission and distribution system between the points of generation and the points of consumption by end-users allow the same overall demand for electricity services to be met with a smaller overall quantity of electricity generation. Such reductions in generation quantities would tend to reduce generation by affected EGUs, thereby reducing CO_2 emissions. The opportunity for improvement is large because, on average, line losses account for approximately seven percent of all electricity generation. The EPA recognizes that, in general, only the owner/operators of the transmission and distribution facilities have the ability to undertake line loss reduction investments, and that merchant generators may have little opportunity to engage a contractor to pursue such opportunities on a bilateral basis. Nevertheless, for entities that do have the opportunity to make such investments, generation avoided through investment that reduces transmission and distribution line losses may serve as the basis for issuance of ERCs that in turn can be used by affected EGUs. Further information is provided in section VIII.K.

7. Severability

The EPA intends that the components of the BSER summarized above be severable. It is reasonable to consider the building blocks severable because the building blocks do not depend on one another. Building blocks 2 and 3 are feasible and demonstrated means of reducing CO_2 emissions from the utility power sector that can be implemented independently of the other building blocks. If implemented in combination with at least one of the other building blocks, building block 1 is also a feasible and demonstrated means of reducing CO_2 emission from the utility power sector.[443] As discussed in sections V.C. through V.E. below, we have determined that each building block is independently of reasonable cost whether or not the other building blocks are applied, and that alternative combinations of the building blocks are likewise of reasonable cost, and we have determined reasonable schedules and stringencies for implementation of each building block independently, based on factors that generally do not vary depending on the implementation of other building blocks.

Further, building block 2, building block 3, and all combinations of the building blocks (implemented on the schedules and at the stringencies determined to be reasonable in this rule) would achieve meaningful

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[443] The heat rate improvement measures included in building block 1 are capable of being implemented independently of the measures in the other building blocks but, as discussed earlier, unless at least one other building block is also implemented, a "rebound effect" arising from improved competitiveness and increased generation at the EGUs implementing heat rate improvements could weaken or potentially even eliminate the ability of building block 1 to achieve CO_2 emission reductions.

degrees of emission reductions,[444] although less than the combination of all three building blocks. No combination of the building blocks would lead to adverse non-air environmental or energy impacts or impose a risk to the reliability of electricity supplies.

In the event that a court should deem building block 2 or 3 defective, but not both, the standards and state goals can be recomputed on the basis of the remaining building blocks. All of the data and procedures necessary to determine recomputed state goals using any combination of the building blocks are set forth in the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule available in the docket.

B. Legal Discussion of Certain Aspects of the BSER

This section includes a legal analysis of various aspects of EPA's determination of the BSER, including responses to some of the major adverse comments. These aspects include (1) the EPA's authority to determine the BSER; (2) the approach to subcategorization; (3) the EPA's basis for determining that building blocks 2 and 3 qualify as part of the BSER under CAA sections 111(d)(1) and (a)(1), notwithstanding commenters' arguments that these building blocks cannot be considered part of the BSER because they are not based on measures integrated into the design or operation of the affected source's own production processes or methods or because they are dependent on actions by entities other than the affected source; (4) the relationship between an

[444] This conclusion would not extend to a BSER comprising solely building block 1, in part because of the possibility of rebound effects discussed earlier.

affected EGU's implementation of building blocks 2 and 3 and CO_2 emissions reductions; (5) how reduced generation relates to the BSER; (6) reasons why, contrary to assertions by commenters, this rule is within the EPA's statutory authority, is not inconsistent with the Federal Power Act or state laws governing public utility commissions, and does not result in what the U.S. Supreme Court described as "an enormous and transformative expansion in [the] EPA's regulatory authority";[445] and (7) reasons that, contrary to assertions by commenters, the stringency of the BSER for this rule for CO_2 emissions from existing affected EGUs is not inconsistent with the stringency of the BSER for the rules the EPA is promulgating at the same time for CO_2 emissions from new or modified affected EGUs.

1. The EPA's Authority To Determine the BSER

In this section, we explain why the EPA, and not the states, has the authority to determine the BSER and, therefore, the level of emission limitation required from the existing sources in the source category in section 111(d) rulemaking and the associated state plans.

CAA section 111(d)(1) requires the EPA to establish a section 110-like procedure under which each state submits a plan that "establishes standards of performance for any existing source of air pollutant" and "provides for the implementation and enforcement of such standards of performance." As CAA section 111(d) was originally adopted in the 1970 CAA Amendments, however, state plans were required to

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[445] *Util. Air Reg. Group* v. *EPA*, 134 S. Ct. 2427, 2444 (2014).

establish “emission standards”—an undefined term—rather than “standards of performance,” a term that was limited to CAA section 111(b).[446] The 1970 provision was in effect when the EPA issued the 1975 implementing regulations for CAA section 111(d),[447] which remain in effect to this day.

These regulations establish a cooperative framework that is similar to that under CAA section 110. First, the EPA develops “emission guidelines” for source categories, which are defined as a final guideline document reflecting “the degree of emission reduction achievable through the application of the best system of emission reduction . . . which the Administrator has determined has been adequately demonstrated.” Then, the states submit implementation plans to regulate any existing sources.[448]

The preamble to these regulations carefully considered the allocation of responsibilities as between the EPA and the states for purposes of CAA section 111(d), and concluded that the EPA is responsible for determining the level of emission limitation from the source category, while the states have the responsibility of assigning emission requirements to their sources that assured their

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[446] *See* 1970 CAA Amendments, § 4, 84 Stat. at 1683–84. Subsequently, in 1977, Congress replaced the term “emission standard” with “standards of performance.” *See* 1977 CAA Amendments, § 109, 91 Stat. at 699.

[447] *See* “State Plans for the Control of Certain Pollutants From Existing Facilities,” 40 FR 53340 (Nov. 17, 1975).

[448] *See* “State Plans for the Control of Certain Pollutants From Existing Facilities,” 40 FR 53340 (Nov. 17, 1975).

achievement of that level of emission limitation.[449] The EPA explained "that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans."[450] The EPA added, "it would make no sense to interpret [CAA] section 111(d) as requiring the Administrator to base approval or disapproval of state plans solely on procedural criteria. Under that interpretation, states could set extremely lenient standards—even standards permitting greatly increased emissions—so long as [the] EPA's procedural requirements were met."[451] The EPA concluded that "emission guidelines, each of which will be subjected to public comment before final adoption, will serve [the] function" of providing substantive criteria "in advance to the states, to industry, and to the general public" to aid states in "developing and enforcing control plans under [CAA] section 111(d)."[452] Thus, the implementing regulations make clear that the EPA is responsible for determining the level of emission limitation that the state plans must achieve.

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[449] As we made clear in the proposed rulemaking, we are not re-opening these regulations (on the issue of the authority to determine the BSER or any other issue, unless specifically indicated otherwise) in this rulemaking, and our discussion of these regulations in responding to comments does not constitute a re-opening.

[450] "State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340, 53342 (Nov. 17, 1975).

[451] "State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340, 53343 (Nov. 17, 1975).

[452] State Plans for the Control of Certain Pollutants from Existing Facilities," 40 FR 53340, 53343 (Nov. 17, 1975).

In 1977, Congress revised CAA section 111(d) to require that the states adopt "standards of performance," as defined under CAA section 111(a)(1). As noted above, a standard of performance is defined as "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 . . . *the Administrator determines* has been adequately demonstrated." (Emphasis added.) By its terms, this provision provides that the EPA has the responsibility of determining whether the "best system of emission reduction" is "adequately demonstrated." By giving the EPA this responsibility, this provision is clear that Congress assigned the role of determining the "best system of emission reduction" to the EPA. Even if the provision may be considered to be silent or ambiguous on that question, the EPA reasonably interprets the provision to assign the responsibility of identifying the "best system of emission reduction" to the Administrator for the same reasons discussed in the preamble to the 1975 implementing regulations.

In addition, in the legislative history of the 1977 CAA Amendments, when Congress replaced the term "emission standards" under CAA section 111(d)(1) with the term "standards of performance," Congress endorsed the overall approach of the implementing regulations, which lends further credence to the proposition that the EPA has the responsibility for determining the "best system of emission reduction" and the amount of emission limitation from the existing sources. Specifically, in the House report that introduced the substantive changes to CAA section 111, the Committee explained that "[t]he

Administrator would establish *guidelines as to what the best system* for each category of existing sources *is."* [453] States, on the other hand, "would be responsible for determining the applicability of such *guidelines* to any particular source or sources."[454] The use of the term "guidelines," which does not appear in CAA section 111(d), indicates Congress was aware of and approved of the approach taken in the EPA's implementing regulations for establishing guidelines, which determine the BSER. At a minimum, if Congress disapproved of the EPA's implementing regulations, we would not expect the House report to adopt the EPA's terminology to clarify CAA section 111(d).

In addition, Congress expressly referred to our "guidelines" in CAA section 129, added as part of the 1990 CAA Amendments. Congress added CAA section 129 to address solid waste combustion and specifically directed the Administrator to establish "*guidelines* (under section 111(d) and this section) and other requirements applicable to existing units."[455] This reference also indicates that Congress was aware of and approved the EPA's regulations under section 111(d).

The EPA has followed the same approach described in the implementation regulations in all its rulemakings under section 111(d). Thus, in all cases, the EPA has identified the type of emission controls for the source category and the level of emission

[453] H.R. Rep. No. 95-294, at 195 (May 12, 1977) (emphasis added).

[454] H.R. Rep. No. 95-294, at 195 (May 12, 1977) (emphasis added).

[455] CAA section 129(a)(1)(A) (emphasis added).

limitation based on those controls.[456] The EPA's longstanding and consistent interpretation of CAA section 111(d) is also "evidence showing that the

[456] *See* 40 CFR part 60, subpart Ca (large municipal waste combustors), 56 FR 5514 (Feb. 11, 1991), 40 CFR 60.30a–.39a (subsequently withdrawn and superseded by Subpart Cb, see 60 FR 65387 (Dec. 19, 1995)); Subpart Cb (large municipal waste combustors constructed on or before September 20, 1994), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30b–.39b (as amended in 1997, 2001, and 2006); Subpart Cc (municipal solid waste landfills), 61 FR 9905 (Mar. 12, 1996), 40 CFR 60.30c–.36c (as amended in 1998, 1999, and 2000); Subpart Cd (sulfuric acid production units), 60 FR 65387 (Dec. 19, 1995), 40 CFR 60.30d–.32d; Subpart Ce (hospital/medical/infectious waste incinerators), 62 FR 48348 (Sept. 15, 1997), 40 CFR 60.30e–.39e (as amended in 2009 and 2011); Subpart BBBB (small municipal waste combustion units constructed on or before August 30, 1999), 65 FR 76738 (Dec. 6, 2000), 40 CFR 60.1500–.1940; Subpart DDDD (commercial and industrial solid waste incineration units that commenced construction on or before November 30, 1999), 65 FR 75338 (Dec. 1, 2000), 40 CFR 60.2500–.2875 (as amended in 2005, 2011, and 2013); Subpart FFFF (other solid waste incineration units that commenced construction on or before December 9, 2004), 70 FR 74870 (Dec. 16, 2005), 40 CFR 60.2980–.3078 (as amended in 2006); Subpart HHHH (coal-electric utility steam generating units), 70 FR 28606 (May 18, 2005) (subsequently vacated by the D.C. Circuit in *New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008)); Subpart MMMM (existing sewage sludge incineration units), 76 FR 15372 (Mar. 21, 2011), 40 CFR 60.5000–.5250; "Phosphate Fertilizer Plants, Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977) (not codified); "Kraft Pulp Mills; Final Guideline Document; Availability," 44 FR 29828 (May 22, 1979) (not codified); and "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980) (not codified).

statute is in fact not ambiguous," and that the EPA's interpretation should be adopted.[457]

Lastly, this interpretation is consistent with the Supreme Court's reading of CAA section 111(d) in *American Electric Power Co.* There, the Court explained that "EPA issues emissions guidelines, see 40 CFR 60.22, .23 (2009); in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction, § 7411(d)(1)."[458]

As noted in the response to comment document, some commenters agreed with our interpretation, just discussed, while others argued that the states should be given the authority to determine the best system of emission reduction and, therefore, the level of emission limitation from their sources. For the reasons just discussed, this latter interpretation is an incorrect interpretation of CAA section 111(d)(1) and (a)(1), and we are not compelled to abandon our longstanding practice.

2. Approach to Subcategorization

As noted above, in this rule, we are treating all fossil fuel-fired EGUs as a single category, and, in the emission guidelines that we are promulgating with this rule, we are treating steam EGUs and combustion turbines as separate subcategories. We are determining the BSER for steam EGUs and the BSER

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[457] Scalia, Antonin, *Judicial Deference to Administrative Interpretations of Law*, 1989 Duke L.J. 511, 518; see *Riverkeeper* v. *Entergy*, 556 U.S. 208, 235 (2009).

[458] *Am. Elec. Power Co.* v. *Connecticut*, 131 S. Ct. 2527, 2537–38 (2011).

for combustion turbines, and applying the BSER to each subcategory to determine a performance rate for that subcategory. We are not further subcategorizing among different types of steam EGUs or combustion turbines.

This approach is fully consistent with the provisions of section 111(d), which simply require the EPA to determine the BSER, do not prescribe the method for doing so, and are silent as to subcategorization. This approach is also fully consistent with other provisions in CAA section 111, which require the EPA first to list source categories that may reasonably be expected to endanger public health or welfare [459] and then to regulate new sources within each such source category, [460] and which grant the EPA discretion whether to subcategorize new sources for purposes of determining the BSER.[461]

For this rule, our approach of subcategorizing between steam EGUs and combustion turbines is reasonable because building blocks 1 and 2 apply only to steam EGUs. No further subcategorization is appropriate because each affected EGU can achieve the performance rate by implementing the BSER. Specifically, as noted, each affected EGU may take a range of actions including investment in the building blocks, replacing or reducing generation, and emissions trading, as enabled or facilitated by the implementation programs the states adopt. Further, in the case of a rate-based state plan, several other

[459] CAA section 111(b)(1)(A).

[460] CAA section 111(b)(1)(B).

[461] CAA section 111(b)(2).

compliance options not included in the BSER for this rule are also available to all affected sources, including investment in demand-side EE measures. Such compliance options help affected sources achieve compliance under a mass-based plan, even if indirectly. Our approach to subcategorization in this rule is consistent with our approach to subcategorization in previous section 111 rules for this industry, in which we determined whether or not to subcategorize on the basis of the ability of affected EGUs with different characteristics (*e.g.*, size or type of fuel used) to implement the BSER and achieve the emission limits).[462]

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[462] *Compare* "Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Revisions to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units: Final Rule," 63 FR 49442 (Sept. 16, 1998) *and* "Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units: Proposed Revisions," 62 FR 36948, 36943 (July 9, 1997) (establishing a single NO_X emission limit for new fossil-fuel fired steam generating units, and not subcategorizing, because the affected units could implement the BSER of SCR and achieve the promulgated emission limits) *with* "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Final Rule," 77 FR 9304 (Feb. 16, 2012) (MATS rule) *and* "National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units: Proposed Rule," 76 FR 24976, 25036–37 (May 3, 2011) (subcategorizing coal fired units designed to burn coal with

In addition, there are numerous possible criteria to use in subcategorizing, including, among others, subcategorizing on the basis of age; size; steam conditions (*i.e.*, subcritical or supercritical); type of fuel, including type of coal (*i.e.*, lignite, bituminous, and sub-bituminous), and coal refuse; and method of combustion (*i.e.*, fluidized bed combustion, pulverized coal combustion, and gasification). In addition, there are different possible combinations of those categories. At least some of those criteria do not have logical cut-points. Furthermore, we have not been presented with, nor can we discern, a method of subcategorizing based on these or other criteria that is appropriate in light of the BSER for the affected EGUs and their ability to meet the emission limits. Moreover, our approach of not further subcategorizing as between different types of steam EGUs or combustion turbines reflects the reasonable policy that affected EGUs with higher emission rates should reduce their emissions by a greater percentage than affected EGUs with lower emission rates, and can do so by implementing the BSER we are identifying.

In addition, a section 111(d) rule presents less of a need to subcategorize because the states retain great

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greater than or equal to 8,300 Btu/lb (for Hg emissions only), coal-fired units designed to burn coal with less than 8,300 Btu/lb (for Hg emissions only), IGCC units, liquid oil units, and solid oil-derived units; evaluating "subcategorization of lignite coal vs. other coal ranks; subcategorization of Fort Union lignite coal vs. Gulf Coast lignite coal vs. other coal ranks; subcategorization by EGU size (*i.e.*, MWe); subcategorization of base load vs. peaking units (*e.g.*, low capacity utilization units); subcategorization of wall-fired vs. tangentially-fired units; and subcategorization of small, non-profit-owned units vs. other units;" but deciding not to adopt those latter subcategorizations).

flexibility in assigning standards of performance to their affected EGUs. Thus, a state can, if it wishes, impose different emission reduction obligations on its sources, as long as the overall level of emission limitation is at least as stringent as the emission guidelines, as discussed below. This means that if a state is concerned that its different sources have different capabilities for compliance, it can adjust the standards of performance in imposes on its sources accordingly.

3. Building Blocks 2 and 3 as a "System of Emission Reduction"

a. *Overview.*

As we explain above, the emission performance rates that we include in this rule's emission guidelines are achievable by the affected EGUs through the application of the BSER, which includes the three building blocks. Commenters object that building blocks 2 (generation shift) and 3 (RE) cannot, as a legal matter, be considered part of the BSER under CAA section 111(d)(1) and (a)(1). These commenters explain that in their view, under CAA section 111, the emission performance rates must be based on, and therefore the BSER must be limited to, methods for emission control that the owner/ operator of the affected source can integrate into the design or operation of the source itself, and cannot be based on actions taken beyond the source or actions involving third-party entities. [463] For these reasons, these

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[463] *See, e.g.*, comments by UARG at 6–7 ("Standards promulgated under section 111 must be source-based and reflect measures that the source's owner can integrate into the design or operation of the source itself. A standard cannot be based on

commenters argue that the phrase "system of emission reduction" cannot be interpreted to include building blocks 2 and 3.

We disagree with these comments, and note that other commenters were supportive of our determination to include building blocks 2 and 3. Under CAA section 111(d)(1) and (a)(1), the EPA's emission guidelines must establish achievable emission limits based on the "best system of emission reduction . . . adequately demonstrated." While some commenters assert that emission guidelines must be limited in the manner summarized above, the phrase "system of emission reduction," by its terms and when read in context, contains no such limits. To the contrary, its plain meaning is deliberately broad and is capacious enough to include actions taken by the owner/operator of a stationary source designed to

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actions taken beyond the source itself that somehow reduce the source's utilization."); comments by UARG at 31 (the building blocks other than building block 1 take a "'beyond-the-source' approach" and "impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators"); comments by UARG at 33 (the "system" of emission reduction "can refer only to reductions resulting from measures that are incorporated into the source itself;" section 111 is "designed to improve the emissions performance of new and existing sources in specific categories based on the application of achievable measures implemented in the design or production process of the source at reasonable cost."); comments by American Chemistry Council et al. ("Associations") at 60–61 (EPA's proposed BSER analysis is unlawful because it "looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;" "the standard of performance must . . . be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.").

reduce emissions from that affected source, including actions that may occur off-site and actions that a third party takes pursuant to a commercial relationship with the owner/operator, so long as those actions enable the affected source to achieve its emission limitation. Such actions include the measures in building blocks 2 and 3, which, when implemented by an affected source, enable the source to achieve their emission limits because of the unique characteristics of the utility power sector. For purposes of this rule, we consider a "system of emission reduction"—as defined under CAA section 111(a)(1) and applied under CAA section 111(d)(1)—to encompass a broad range of pollution-reduction actions, which includes the measures in building blocks 2 and 3. Furthermore, the measures in building blocks 2 and 3 fall squarely within EPA's historical interpretation of section 111, pursuant to which the focus for the BSER has been on how to most cleanly produce a good, not on how much of the good should be produced.

Our interpretation that a "system of emission reduction" is broad enough to include the measures in building blocks 2 and 3 is supported by the following: Our interpretation of the phrase "system of emission reduction" is consistent with its plain meaning and statutory context; our interpretation accommodates the very design of CAA section 111(d)(1), which covers a range of source categories and air pollutants; [464] our interpretation is supported by the legislative history

[464] Because it is designed to apply to a range of air pollutants not regulated under other provisions, CAA section 111(d) may be described as a "catch-all" or "gap-filler." As such, a "system of emission reduction" as applied under CAA section 111(d) should be interpreted flexibly to accommodate this role.

of CAA section 111(d)(1) and (a)(1), which indicates Congress's intent to give the EPA broad discretion in determining the basis for CAA section 111 control requirements, particularly for existing sources, and Congress's intent to authorize the EPA to consider measures that could be carried out by parties other than the affected sources; and our interpretation is reasonable in light of comparisons to CAA provisions that give the EPA similar authority to consider such measures and to CAA provisions that would preclude the EPA from considering such measures.

In addition to the reasons stated above, the EPA's interpretation is also reasonable for the following reasons: (i) Building blocks 2 and 3 fit well within the structure and economics of the utility power sector. (ii) Fossil fuel-fired EGUs are already implementing the measures in these building blocks for various reasons, including for purposes of reducing CO_2 emissions. (iii) Interpreting the phrase "system of emission reduction" to incorporate building blocks 2 and 3 is consistent with (a) other provisions in the CAA, including the acid rain provisions in Title IV and the SIP provisions in CAA section 110, along with the EPA's regulations implementing the CAA SIP requirements concerning interstate transport and regional haze, each of which is based on at least some of the same measures included in building blocks 2 and 3; (b) prior EPA action under CAA section 111(d), including the 2005 Clean Air Mercury Rule,[465] which is based on some of

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[465] This rule was vacated by the D.C. Circuit on other grounds. *New Jersey* v. *EPA*, 517 F.3d 574, 583–84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group* v. *New Jersey*, 555 U.S. 1169 (2009).

the same measures in building blocks 2 and 3; (c) the various provisions of the CAA that authorize emissions trading, because emissions trading entails a source meeting its emission limitation based on the actions of another entity; and (d) the pollution prevention provisions of the CAA, which make clear that a primary goal of the CAA is to encourage federal and state actions that reduce or eliminate, through any measures, the amount of pollution produced at the source.[466] (iv) Lastly, interpreting the phrase "system of emission reduction" to authorize the EPA, in formulating its BSER determination, to weigh a broad range of emission-reducing measures that includes building blocks 2 and 3 is consistent with Congress's intent to address urgent environmental problems and to protect public health and welfare against risks, as well as Congress's expectation that American industry would be able to develop the innovative solutions necessary to protect public health and welfare.

Congress passed the CAA, including its several amendments, to protect public health and welfare from "mounting dangers," including "injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation."[467] In doing so, Congress established numerous programs to address air pollution problems and provided the EPA with

[466] As noted in the Legal Memorandum, in several of these rulemakings and in the course of litigation, the fossil fuel-fired electric power sector has taken positions that are consistent with the EPA's interpretation that the BSER may include building blocks 2 and 3.

[467] CAA section 101(a)(2).

guidance and flexibility in carrying out many of those programs. Even if we were to accept commenters' view that the system of emission reduction identified as best here is not integrated into the design or operation of the regulated sources, in the context of this industry and this pollutant it is reasonable to reject the narrow interpretation urged by some commenters that the "system of emission reduction" applicable to the affected EGUs must be limited to only those measures that can be integrated into the design or operation of the source itself. The plain language of the statute does not support such an interpretation, and to adopt it would limit the "system of emission reduction" to measures that are either substantially more expensive or substantially less effective at reducing emissions than the measures in building blocks 2 and 3, notwithstanding the absence of any statutory language imposing such a limit. Such a result would be contrary to the goals of the CAA and would ignore the facts that sources in the electric generation industry routinely address planning and operating objectives on a broad, multi-source basis using the measures in building blocks 2 and 3 and would seek to use building blocks 2 and 3 (as well as non-BSER measures) to comply with whatever emission standards are set as a result of this rule. Indeed, as already observed, building blocks 2 and 3 are already being used to reduce emissions, and to do so specifically by operation of the industry's inherent multi-source functions.

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of measures that may be included in the BSER. We discuss those constraints at the end of this section. They include the section 111(d)(1) and (a)(1) requirements that emission reductions occur from the affected sources; that the emission performance standards for which the BSER forms the basis be achievable; that the system of emission reduction be adequately demonstrated; and that the EPA account for cost, non-air quality impacts, and energy requirements in determining the "best" system of emission reduction that is adequately demonstrated. The constraints included in these statutory requirements do not preclude building blocks 2 and 3 from the BSER. In interpreting these statutory requirements for determining the BSER, the EPA is consistent with past practice and current policy for both section 111 regulatory actions as well as regulatory actions under other CAA provisions for the electric power sector, under which the EPA has generally taken the approach of basing regulatory requirements on controls and measures designed to reduce air pollutants from the production process without limiting the aggregate amount of production. This approach has been inherent in our past interpretation and application of section 111 and we maintain this interpretation in this rulemaking.[468] While inclusion

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[468] As we note in section V.A., this rulemaking presents a unique set of circumstances, including the global nature of CO_2 and the emission control challenges that CO_2 presents (which limit the availability and effectiveness of control measures), combined with the facts that the electric power industry (including fossil fuel-fired steam generators and combustion turbines) is highly integrated, electricity is fungible, and generation is substitutable (which all facilitate the generation shifting measures encompassed in building blocks 2 and 3). Our

of building blocks 2 and 3 is consistent with our interpretation of the statutory requirements, inclusion of building block 4 is not, and for that reason, we are declining to include building block in the BSER. Finally, we briefly note additional constraints that focus the BSER identified for new sources under section 111(b) on controls that assure that sources are well-controlled at the time of construction.

b. *System of emission reduction as a broad range of measures.*

(1) *Plain meaning and context of "system of emission reduction."*

The phrase "system of emission reduction" appears in the definition of a "standard of performance" under CAA section 111(a)(1). That definition reads:

> 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Pursuant to this definition, it is clear that a "system of emission reduction" serves as the basis for emission limits embodied by CAA section 111 standards. For this reason, emission limits must be "achievable" through the "application" of the "best" "system of

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interpretation of section 111 as focusing on limiting emissions without limiting aggregate production must take into account those unique circumstances.

emission reduction" "adequately demonstrated." Under CAA section 111(d)(1), such a limit is established for "any existing source," which is defined as any existing "building, structure, facility, or installation which emits or may emit any air pollutant."[469]

Although a "system of emission reduction" lays the groundwork for CAA section 111 standards, the term "system" is not defined in the CAA. As a result, we look first to its ordinary meaning.

Abstractly, the term "system" means a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent elements.[470] As a phrase, "system of emission reduction" takes a broad meaning to serve a singular

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[469] *See* CAA section 111(d)(1) (applying a standard of performance to any existing source); (a)(6) (defining the term "existing source" as any stationary source other than a new source); and (a)(3) (defining the term "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant," however, explaining that "[n]othing in subchapter II [*i.e.*, Title II] of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.")

[470] *Oxford Dictionary of English* (3rd ed.) (2010), *available at http://www.oxforddictionaries.com/us/definition/american_english/system*; *see also* American Heritage Dictionary (5th ed.) (2013), available at *http://www.yourdictionary.com/system#americanheritage*; and *The American College Dictionary (C.L. Barnhart, ed. 1970) ("an assemblage or combination of things or parts forming a complex or unitary whole").*

purpose: It is a set of measures that work together to reduce emissions.

When read in context, the phrase "system of emission reduction" carries important limitations: because the "degree of emission limitation" must be "*achievable* through the *application* of the best system of emission reduction," (emphasis added), the "system of emission reduction" must be limited to a set of measures that work together to reduce emissions and that are implementable by the sources themselves.

As a practical matter, the "source" includes the "owner or operator" of any building, structure, facility, or installation for which a standard of performance is applicable. For instance, under CAA section 111(e), it is the "owner or operator" of a source who is prohibited from operating "in violation of any standard of performance applicable to such source."[471]

Thus, a "system of emission reduction" for purposes of CAA section 111(d) means a set of measures that source owners or operators can implement to achieve an emission limitation applicable to their existing source.[472]

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[471] While this section provides for enforcement in the context of new sources, a CAA section 111(d) plan must provide for the enforcement of a standard of performance for existing sources.

[472] Some commenters read the proposed rulemaking as taking the position that the phrase "system of emission reduction" includes anything whatsoever that reduces emissions, and criticized that interpretation as too broad. *See* UARG comment, at 3–4. We are not taking that interpretation here. In this final rule, we agree that the phrase should be limited to exclude, *inter alia*, actions beyond the ability of the owners/operators to control.

In contrast, a "system of emission reduction" does not include actions that only a state or other governmental entity could take that would have the effect of reducing emissions from the source category, and that are beyond the ability of the affected sources' owners/operators to take or control. Additionally, actions that a source owner or operator could take that would not have the effect of reducing emissions from the source category, such as purchasing offsets, would also not qualify as a "system of emission reduction."

Building blocks 2 and 3 each fall within the meaning of a "system of emission reduction" because they consist of measures that the owners/ operators of the affected EGUs can implement to achieve their emission limits. In doing so, the affected EGUs will achieve the overall emission reductions the EPA identifies in this rule. We describe these building block 2 and 3 measures in detail elsewhere in this rule, including the specific actions that owners/operators of affected EGUs can take to implement the measures.

It should be noted that defining the scope of a "system of emission reduction" is not the end of our inquiry under CAA section 111(a)(1); rather, as noted above, a standard of performance must reflect the application of the "*best* system of emission reduction . . . *adequately demonstrated."* (Emphasis added.) Thus, in determining the BSER, the Administrator must first determine whether the available systems of emission reduction are "adequately demonstrated," based on the criteria, described above, set out by Congress in the legislative history and the D.C. Circuit in case law. After identifying the "adequately demonstrated" systems of emission reduction, the Administrator then selects the "best" of these, based on several factors, including amount of emission reduction, cost, non-air quality health and environmental impact and energy requirements. Only after the Administrator weighs all of these considerations can she determine the BSER and, based on that, establish a standard of performance under CAA section 111(b) or an emission guideline under CAA section 111(d).

For purposes of this final rule, it is not necessary to enumerate all of the types of measures that do or do not constitute a "system of emission reduction." What is relevant is that building blocks 2 and 3 each qualify as part of the "system of emission reduction." As noted, they focus on supply-side activities and they each constitute measures that the affected EGUs can implement that will allow those EGUs to achieve the degree of emission limitation that the EPA has identified based on those building blocks. Further, these building blocks also satisfy the other statutory criteria enumerated in CAA section 111(a)(1).

(2) *Other indications that the BSER provisions encompass a broad range of measures*.

The EPA's plain meaning interpretation that the BSER provisions in CAA section 111(d)(1) and (a)(1) are designed to include a broad range of measures, including building blocks 2 and 3, is supported by several other indications in the CAA and the legislative history of section 111.

(a) *Scope of CAA section 111(d)(1).*

First, the broad scope of CAA section 111(d)(1) supports our interpretation of the BSER because a wide range of control measures is appropriate for the wide range of source categories and air pollutants covered under CAA section 111(d).

In the 1970 CAA Amendments, Congress established a regulatory regime for existing stationary sources of air pollutants that may be envisioned as a three-legged stool, designed to address "three categories of pollutants emitted from stationary sources": (1) Criteria pollutants (identified under CAA section 109 and regulated under section 110); (2) hazardous air pollutants (identified and regulated under section 112); and (3) "pollutants that are (or may be) harmful to public health or welfare but are not" criteria or hazardous air pollutants. [473] Congress enacted CAA section 111(d) to cover this third category of air pollutants and, in this sense, Congress designed it to apply to any air pollutants that were not otherwise regulated as toxics or NAAQS pollutants.[474] This would include air pollutants that the EPA might later, when more information became available, designate as NAAQS or hazardous air pollutants, as well as air pollutants that Congress may not have been aware of at the time.[475] In addition, the indications are

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[473] 40 FR 53340, 53340 (Nov. 17, 1975) (EPA regulations implementing CAA section 111(d)).

[474] *See* S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 ("It should be noted that the emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [*i.e.*, the bill's version of CAA section 112] could be established under section 114 [*i.e.*, the bill's version CAA section 111]. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.").

[475] *See* S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420.

that Congress expected CAA section 111(d) to be a significant source of regulatory activity, by some measures, more active than CAA section 112. This is evident because Congress expected that CAA section 111(d) would cover more air pollutants than either CAA section 109/ 110 (criteria pollutants) or CAA section 112 (hazardous air pollutants).[476] In addition, in the 1990 CAA Amendments, Congress enacted CAA section 129 to achieve emission reductions from a major source category, solid waste incinerators, and established CAA section 111(d) as the basic mechanism for that provision. The EPA subsequently promulgated a number of CAA section 129/111(d) rulemakings.[477] Finally, it should be noted that Congress designed CAA section 111(d) to cover a wide range of source categories—including any source category that the EPA identifies under subsection

[476] *See* S. Rep. No. 91-1196, at 9; 18–20, 1970 CAA Legis. Hist. at 418–20. The Senate Committee Report identified 14 substances as subject to the provision that became section 111(d), four substances as hazardous air pollutants that would be regulated under the provision that became section 112, and 5 substances as criteria pollutants that would be regulated under the provisions that became sections 109–110 (and more "as knowledge increases"). In particular, the Report recognized that in particular, relatively few air pollutants may qualify as hazardous air pollutants, but that other air pollutants that did not qualify as hazardous air pollutants would be regulated under what became section 111(d).

[477] *See, e.g.*, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, 62 FR 48348, 48359 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 65 FR 75338, 75341 (Dec. 1, 2000).

111(b)(1)(A) as meeting the criteria of, in general, causing or contributing significantly to air pollution that may reasonably be anticipated to endanger public health or welfare—along with the wide range of air pollutants.

Because Congress designed CAA section 111(d) to cover a wide range of air pollutants—including ones that Congress may not have been aware of at the time it enacted the provision—and a wide range of industries, it is logical that Congress intended that the BSER provision, as applied to CAA section 111(d), have a broad scope so as to accommodate the range of air pollutants and source categories.

(b) *Legislative history of CAA section 111.*

(i) *Breadth of "system of emission reduction."*

The phrase "system of emission reduction," particularly as applied under CAA section 111(d), should be broadly interpreted consistent with its plain meaning but also in light of its legislative history. The version of CAA section 111(d)(1) that Congress adopted as part of the 1970 CAA Amendments read largely as CAA section 111(d)(1) does at present, except that it required states to impose "emission standards" on any existing source. (Congress replaced that term with "standards of performance" in the 1977 CAA Amendments.) The 1970 CAA Amendments version of CAA section 111(d)(1) neither defined "emission standards" nor imposed restrictions on the EPA in determining the basis for the emission standards.[478]

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[478] Although not defined under CAA section 111, the term was used in other provisions and defined in some of them. The term

For new sources, CAA section 111(b)(1)(B), as enacted in the 1970 CAA Amendments (and as it largely still reads), required the EPA to promulgate "standards of performance," and defined that term, much like the present definition, as emission standards based on the "best system of emission reduction . . . adequately demonstrated." This quoted phrase was not included in either the House or Senate versions of the provision, and, instead, was added during the joint conference between the House and Senate. The conference report accompanying the text offers no clarifications.

The House and Senate bills do, however, provide some insights. The House bill, H.R. 17255, would have required new sources of non-hazardous air pollutants to "prevent and control such emissions to the fullest extent compatible with the available technology and

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was defined under the CAA's citizen suit provision. *See* 1970 CAA Amendments, Pub. L. 91-604, § 12, 84 Stat. 1676, 1706 (Dec. 31, 1970) (defined as "(1) a schedule or timetable of compliance, emission limitation, standard of performance or emission standard, or (2) a control or prohibition respecting a motor vehicle fuel or fuel additive. . . ."). Congress also used it in the CAA's NAAQS provisions and in CAA section 112. Under the CAA's NAAQS provisions (*i.e.*, the "Ambient Air Quality and Emission Standards" provisions), Congress directed the EPA to issue information on "air pollution control techniques," and include data on "available technology and alternative methods of prevention and control of air pollution" as well as on "alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions." *Id.*, § 4, 84 Stat, at 1679. Similarly, under CAA section 112, the Administrator was required to "from time to time, issue information on pollution control techniques for air pollutants" subject to emission standards. *Id.*, 84 Stat. at 1685. These statements provide additional context for the term's broad intent.

economic feasibility, as determined by the Secretary."[479] The Senate bill, S. 4358, would have established "Federal standards of performance for new sources," which, in turn, were to "reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, *or other alternatives*."[480] The Senate Committee Report explains that "performance standards should be met through application of the latest available emission control technology or through *other means of preventing or controlling air pollution*."[481] This Report further elaborates that the term "standards of performance"

> refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods*. The Secretary should not make a technical judgment as to how the standard should be implemented. He should determine the achievable limits and let the owner or operator determine the most economic, acceptable *technique* to apply.[482]

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[479] 470 H.R. 17255, §5, 1970 CAA Legis. Hist. at 921–22. The reference to "Secretary" was to the Secretary of Health Education and Welfare, which, at the time, was the agency with responsibility for air pollution regulations.

[480] S. 4358, § 6, 1970 Legis. Hist. at 554–55 (emphasis added).

[481] S. Rep. No. 91-1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (emphasis added).

[482] S. Rep. No. 91-1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (emphasis added).

Thus, the Senate bill clearly envisioned that standards of performance would not be based on a particular technology or even a particular method to prevent or control air pollution.[483] This vision contrasted with the House bill, which would have restricted performance standards to economically feasible technical controls.

Following the House-Senate Conference, the enacted version of the legislation defined a "standard of performance" 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) the Administrator determines has been adequately demonstrated.[484]

While the phrase "system of emission reduction" was not discussed in the Conference Report, an exhibit titled "Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970" was added to the record during the Senate's consideration of the Conference Report and sheds some light on the phrase. According to the summary, "[t]he agreement authorizes regulations to require

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[483] Notably, the Senate report identifies pollution control *and* pollution prevention as objectives of the Senate provision. Pollution prevention is discussed more generally below as a "primary purpose" of the CAA, however, the report makes clear that pollution prevention measures—which the EPA understands to include such measures as building blocks 2 and 3—are appropriate under CAA section 111.

[484] CAA section 111(a)(1) under the 1970 CAA Amendments (emphasis added).

that new major industry plants such as power plants, steel mills, and cement plants achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives."[485] In light of this summary, the phrase "system of emission reduction" appears to blend the broad spirit of S. 4358 (which required the "latest available control technology, processes, operating methods, or other alternatives") with the cost concerns identified in H.R. 17255 (which required consideration of "economic feasibility" when establishing federal emission standards for new stationary sources). This history strongly suggests that Congress intended to authorize the EPA to consider a wide range of measures in calculating a standard of performance for stationary sources. At a minimum, there is no indication that Congress intended to preclude measures or actions such as the ones in building blocks 2 and 3 from the EPA's assessment of the BSER.

Notwithstanding this broad approach, as we discuss in the Legal Memorandum, the legislative history of the 1970 CAA Amendments also indicates that Congress intended that new sources be well-controlled at the source, in light of their expected lengthy useful lives.

In 1977, Congress amended CAA section 111(a)(1) to limit the types of controls that could be the basis of standards of performance for new sources to technological controls. Congress was clear, however, that existing source standards, which were no longer

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[485] Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91-1783 (Dec. 17, 1970), 1970 CAA Legis. Hist. at 130.

developed as "emission standards," would not be limited to technological measures. Specifically, the 1977 CAA Amendments revised CAA section 111(a)(1) to require all new sources to meet emission standards based on the reductions achievable through the use of the "best technological system of continuous emission reduction."[486] According to the legislative history, [t]his mean[t] that new sources may not comply merely by burning untreated fuel, either oil or coal."[487] The new requirement stemmed in part from Congress's concern over the shocks that the country experienced during the 1973–74 Arab Oil Embargo, which led Congress to revise CAA section 111 to "encourage and facilitate the increased use of coal, and to reduce reliance (by new and old sources alike), upon petroleum to meet emission requirements."[488] Imposing a new technological requirement (along with a new percentage reduction requirement) under CAA section 111 was designed to "force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance."[489] Congress nonetheless recognized that despite narrowing new source standards to the best "technological system of continuous emission

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[486] CAA section 111(a)(1) (1977).

[487] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.

[488] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2659.

[489] *New Stationary Sources Performance Standards; Electric Utility Steam Generating Units*, 44 FR 33580, 33581–33582 (June 11, 1979).

reduction," many "innovative approaches may in fact reduce the economic and energy impact of emissions control," and the Administrator should still be encouraged to consider other technologically based techniques for emissions reduction, including "precombustion cleaning or treatment of fuels."[490] This is discussed in more detail below.

Despite these changes with respect to new sources, the 1977 CAA Amendments further reinforce the notion that with respect to existing sources, the BSER was never intended to be narrowly applied. In 1977, Congress changed CAA section 111(d)(1) to require that states adopt "standards of performance" and made clear that such standards were to be based on the "best system of continuous emission reduction . . . adequately demonstrated,"[491] but generally maintained the breadth of that term. Although Congress inserted the word "continuous" into the phrase, Congress explained that "standards in the Section 111(d) state plan would be based on the *best available means (not necessarily technological)* for categories of existing sources to reduce emissions."[492]

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[490] H.R. Rep. No. 95-294, at 189 (May 12, 1977), 1977 CAA Legis. Hist. at 2656.

[491] CAA section 111(a)(1)(C) under the 1977 CAA Amendments.

[492] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2662 (emphasis added). Congress also endorsed the EPA's practice of establishing "emission guidelines" under CAA section 111(d). *See* H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2662 ("The Administrator would establish guidelines as to what the best system for each such category of existing sources is. However, the state would be responsible for determining the applicability of such guidelines to any particular source or sources.").

This was intended to distinguish existing source standards from new source standards, for which "the requirement for [BSER] has been more narrowly redefined as best technological system of continuous emission reduction." [493] [494]

In the 1990 CAA Amendments, Congress restored the 1970s vintage definition of a standard of performance as applied to both new and existing sources. With respect to existing sources, this had the effect of no longer requiring that the BSER be "continuous."[495] Further, nothing in the 1990 CAA Amendments or their legislative history indicates that Congress intended to impose new constraints on the types of systems of emission reduction that could be considered under CAA section 111(d)(1) and (a)(1). In

[493] Sen. Muskie, S. Consideration of the H.R. Conf. Rep. No. 95-564 (Aug. 4, 1977), 1977 CAA Legis. Hist. at 353.

[494] In 1977, Congress added a new substantive definition for "emission standard" generally applicable throughout the CAA. 1977 CAA Amendments, Public Law 95-95, § 301, 91 Stat. 685, 770 (Aug. 7, 1977) (defining "emission limitation" and "emission standard" as "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction."). Congress also added a generally applicable definition of standard of performance, defined as "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id.*

[495] We note that the general definition of a standard of performance at CAA section 302(l) still uses "continuous." Even if this provision applies to section 111, it does not affect our analysis in this rule, including our interpretation that BSER includes building blocks 2 and 3.

contrast, Congress retained the definition of the term "technological system of continuous emission reduction," which means "a technological process for production or operation by any source which is inherently low-polluting or nonpolluting," CAA section 111(a)(7)(A), or "a technological system for continuous reduction of the pollution generated by a source before such pollution is emitted into the ambient air, including precombustion cleaning or treatment of fuels," CAA section 111(a)(7)(B).

That term continues to be used in reference to new sources in certain circumstances, under CAA section 111(b), (h), and (j).[496] However, it is not and never has been used to regulate existing sources. In this manner,

[496] There are numerous reasons to find that particular CAA section 111(b) standards of performance should be based on controls installed at the source at the time of new construction. This is due in part to the recognition that new sources have long operating lives over which initial capital costs can be amortized, as recognized in the legislative history for section 111. Thus, new construction is the preferred time to drive capital investment in emission controls. *See*, *e.g*., S. Rep. No. 91-1196, at 15–16, 1970 CAA Legis. Hist. at 416 ("[t]he overriding purpose of this section [concerning new source performance standards] would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach."); *see also* 1977 CAA Amendments, § 109, 91 Stat. at 700, (redefining, with respect to new sources, CAA section 111(a)(1) to reflect the best "technological system of continuous emission reduction" and adding CAA section 111(a)(7) to define this new term). However, as a result of the 1990 revisions to CAA section 111(a)(1), which replaced the phrase "technological system of continuous emission reduction" with "system of emission reduction," new source standards would not be restricted to being based on technological control measures.

the 1990 CAA Amendments further reinforce the breadth and flexibility of the phrase "system of emission reduction," particularly as it applies to existing sources under CAA section 111(d).

For these reasons, the 1970, 1977, and 1990 legislative histories support the EPA's interpretation in this rule that the term is sufficiently broad to encompass building blocks 2 and 3.

(ii) *Reliance on actions taken by other entities*.

The legislative history supports the EPA's interpretation of "system of emission reduction" in another way as well: The legislative history makes clear that Congress intended that standards of performance for electric power plants could be based on measures implemented by other entities, for example, entities that "wash," or desulfurize, coal (or, for oil-fired EGUs, that desulfurize oil). This legislative history is consistent with the EPA's view that the "system of emission reduction" may include actions taken by an entity with whom the owner/operator of the affected source enters into a contractual relationship as long as those actions allow the affected source to meet its emission limitation. By the same token, this legislative history directly refutes commenters' assertions that the phrase "system of emission reduction" must not include actions taken by entities other than the affected sources.[497]

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[497] *See*, *e.g.*, comments by UARG at 31 (the building blocks other than building block 1 take a " 'beyond-the-source' approach" and "impermissibly rely on measures that go beyond the boundaries of individual affected EGUs and that are not within the control of individual EGU owners and operators"); comments by American Chemistry Council *et al.* ("Associations") at 60–61

As noted above, in the 1977 CAA Amendments, Congress revised the basis for standards of performance for new fossil fuel-fired stationary sources to be a "technological system of continuous emission reduction," including "precombustion cleaning or treatment of fuels."[498] Precombustion cleaning or treatment reduces the amount of sulfur in the fuel, which means that the fuel can be combusted with fewer SO_2 emissions, and that in turn means that the source can achieve a lower emission limit. Congress understood that these fuel cleaning techniques would not necessarily be accomplished at the affected source and, in revising CAA section 111(a)(1), wanted to ensure that such techniques would not be overlooked. For example, the 1977 House Committee report indicates that an assessment of the best technological system of continuous emission reduction for fossil fuel-fired power plants would include off-site or third-party pre-combustion techniques for reducing emissions at the source ("*e.g.*, various coal-cleaning technologies such as solvent refining, oil desulfurization *at the refinery*").[499] Thus,

(EPA's proposed BSER analysis is unlawful because it "looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking;" "the standard of performance must . . . be limited to the types of actions that can be implemented directly by an existing source within [the appropriate] class or category.").

[498] 1977 CAA Amendments, §109, 91 Stat, at 700; *see also* CAA section 111(a)(7).

[499] H.R. Rep. No. 95-294 (May 12, 1977), 1977 CAA Legis. Hist. at 2655 (emphasis added). Generally speaking, coal cleaning activities also are conducted by third parties. For instance, EPA recognized in a regulatory analysis of new source performance standards for industrial-commercial-institutional steam

the standard of performance reflecting the best technological system implementable by an affected source could be based, in part, on technologies used at off-site facilities owned and operated by third-parties.

In the 1990 CAA Amendments, Congress eliminated many of the restrictions and other provisions added in the 1977 CAA Amendments by largely reinstating the 1970 CAA Amendments' definition of "standard of performance." Nevertheless, there is no indication that in doing so, Congress intended to preclude the EPA from considering coal cleaning by third parties (which had been considered within the scope of the best system of emission reduction even under the 1970 CAA Amendments), [500] and in fact, the EPA's regulations promulgated after the 1990 CAA Amendments continue to impose standards of performance that are based on third-party coal cleaning.[501]

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generating units that the technology "requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam generating units." U.S. EPA, *Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-lnstitutional Steam Generating Units of Greater than 100 Million Btu/hrHeat Input*, EPA-450/3-86-005, p. 4-4 (June 1986).

[500] *See* U.S. EPA, *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants*, Office of Air Programs Tech. Rep. No. APTD-0711, p. 7 (Aug. 1971) (indicating the "desirability of setting sulfur dioxide standards that would allow the use of low-sulfur fuels *as well as fuel cleaning*, stack-gas cleaning, and equipment modifications" (emphasis added)).

[501] 40 CFR 60.49b(n)(4); see also *Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam*

(c) *Consistency of a broad interpretation of CAA section 111 with the overall structure of the CAA.*

Interpreting CAA section 111(d)(1) and (a)(1) to authorize the EPA's consideration of the building block 2 and 3 measures is consistent with the overall structure of the CAA, particularly as it was amended in 1970, when Congress added CAA section 111 in much the same form that it reads today.

In the 1970 CAA Amendments, for the most part, and particularly for stationary source provisions, Congress painted with broad brush strokes, giving broad authority to the EPA or the states. That is, Congress established general requirements that were intended to produce stringent results, but gave the EPA or the states great discretion in fashioning the types of measures to achieve those results.

For example, under CAA section 109, Congress authorized the EPA to promulgate national ambient air quality standards (NAAQS) for air pollutants, and Congress established general criteria and procedural requirements, but left to the EPA discretion to identify the air pollutants and select the standards. Under CAA section 110, Congress required the states to submit to the EPA SIPs, required that the plans attain the NAAQS by a date certain, and established procedural requirements, but allowed the states broad discretion in determining the substantive requirements of the SIPs.

Under CAA section 111(b), Congress directed the EPA to list source categories that endanger public

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Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule, 72 FR 32742 (June 13, 2007).

health or welfare and established procedural requirements, but did not include other substantive requirements, and instead gave the EPA broad discretion to determine the criteria for endangerment.

Under CAA section 112, Congress required the EPA to regulate certain air pollutants and to set "emission standards" that meet general criteria, and established procedural requirements, but did not include other substantive requirements and, instead, gave the EPA broad discretion in identifying the types of pollutants and in determining the standards.[502] By and large, Congress left these provisions intact in the 1977 CAA Amendments.[503] [504]

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[502] By comparison, under the 1990 CAA Amendments, Congress substantially transformed CAA section 112 to be significantly more prescriptive in directing EPA rulemaking, which reflected Congress's increased knowledge of hazardous air pollutants and impatience with the EPA's progress in regulating.

[503] In the 1977 CAA Amendments, Congress applied the same broad drafting approach to the stratospheric ozone provisions it adopted in CAA sections 150–159. There, Congress authorized the EPA to determine whether, "in the Administrator's judgment, any substance, practice, process, or activity may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, and such effect may reasonably be anticipated to endanger public health or welfare," and then directed the EPA, if it made such a determination, to "promulgate regulations respecting the control of such process practice, process, or activity. . . ." CAA section 157(a). This provision does not further specify requirements for the regulations.

[504] On the other hand, in those instances in which Congress had a clear idea as to the emission limitations that it thought should be imposed, it mandated those emission limits, *e.g.*, in Title II concerning motor vehicles.

Congress drafted the CAA section 111(d) requirements in the 1970 CAA Amendments, and revised them in the 1977 CAA Amendments, in a manner that is similar to the other stationary source requirements, just described, in CAA sections 109, 110, 111(b), and 112. The CAA section 111(d) requirements are broadly phrased, include procedural requirements but no more than very general substantive requirements, and give broad discretion to the EPA to determine the basis for the required emission limits and to the states to set the standards. It should be noted that this drafting approach is not unique to the CAA; on the contrary, Congress "usually does not legislate by specifying examples, but by identifying broad and general principles that must be applied to particular factual instances."[505]

In light of this statutory framework, it is clear that Congress delegated to the EPA the authority to administer CAA section 111, including by authorizing the EPA to apply the "broad and general principles" contained in CAA section 111(a)(1) to the particular circumstances we face today.

(3) *Comments and responses.*

While some commenters support the EPA's interpretation of section 111 to authorize the inclusion of building blocks 2 and 3 in the BSER, other commenters assert that the emission standards must be based on measures that the sources subject to CAA section 111—in this rule, the affected EGUs—apply to their own design or operations, and, as a result, in this

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[505] *Pub. Citizen* v. *U.S. Dept. of Justice*, 491 U.S. 440, 475 (1989) (Kennedy, J., concurring).

rule, cannot include measures implemented at entities other than the affected EGUs that have the effect of reducing generation, and therefore emissions, from the affected EGUs. The commenters assert that various provisions in CAA section 111 make this limitation clear. We do not find those arguments persuasive.

First, some commenters state that under CAA section 111(d)(1) and (a)(1), the existing sources subject to the standards of performance must be able to achieve their emission limit, but that they are able to do so only through measures integrated into the source's own design and operation. As a result, according to these commenters, those are the only types of measures that may qualify as a "system of emission reduction" that may form the basis of the emissions standards. We disagree. We see nothing in CAA section 111(d)(1) or (a)(1) which by its terms limits CAA section 111 to measures that must be integrated into the sources' own design or operation. Rather, we recognize that in order for an emission limitation based on the BSER to be "achievable," the BSER must consist of measures that can be undertaken by an affected source—that is, its owner or operator. As noted elsewhere in the preamble, the affected sources subject to this rule are fully able to meet their emission standards by undertaking the measures described in all three building blocks. Moreover, as discussed, the measures in building blocks 2 and 3 are highly effective in achieving CO_2 emission reductions from these affected EGUs, given the unique characteristics of the industry. This reinforces the conclusion that the term "system of emission reduction" is broad enough to include these measures.

The broad nature of CAA section 111(d)(1) and (a)(1) is also confirmed by comparing it to CAA provisions that explicitly require controls on the design or operations of an affected source. The most notable comparison is at CAA section 111(a)(7). The term "technological system of continuous emission reduction," which was added in 1977 and remains as a separately defined term means, in part, "a technological process *for production or operation* by any source *which is inherently* low-emitting or nonpolluting." (Emphasis added.) With respect to this portion of the definition (and ignoring the additional text, which includes "precombustion cleaning or treatment of fuels" and clearly encompasses off-site activities), it could be argued that between 1977 and 1990 new source performance standards should be restricted to measures that could be integrated into the design or operation of a source. However, commenters' assertion that the BSER must be limited in a similar fashion ignores the deliberate change in 1990 to restore the broader definition of a standard of performance (*i.e.*, that it be based on the BSER and not the TSCER). In any case, the narrower scope of CAA section 111(a)(7) was never applicable to the regulation of existing sources under CAA section 111(d).

Several other examples of standard setting in the CAA shed light on ways in which Congress has constrained the EPA's review. CAA section 407(b)(2) provides that the EPA base NO_X emission limits for certain types of boilers "on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction." (Emphasis added.) Likewise, in determining best available retrofit technology under CAA section 169A, the state (or Administrator) must "take into consideration the costs of compliance, the energy and nonair quality environmental impacts, any existing pollution control technology *in use at the source*, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result *from the use of such technology*."[506] (Emphasis added.) These provisions make clear that Congress knew how to constrain the basis for emission limits to measures that are integrated into the design or operation of the affected source, and that its choice to base CAA section 111(d)(1) and (a)(1) standards of performance on a "system of emission reduction" indicates Congress' intent to authorize a broader basis for those standards.

Some commenters also argue that other provisions in CAA section 111 indicate that Congress intended that CAA section 111(d)(1) and (a)(1) be limited to measures that are integrated into the source's design or operations. This argument is unpersuasive for several reasons. First, it would be unreasonable to presume that Congress intended to limit the BSER, indirectly through these other provisions, to measures that are integrated into the affected source's design or operations, when Congress could have done so

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[506] Even under BART, the EPA is authorized to allow emissions trading between sources. *See, e.g.*, 40 CFR 51.308(e)(1) & (2); *Util. Air Reg. Group* v. *EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Ctr. For Econ. Dev.* v. *EPA*, 398 F.3d 653 (D.C. Cir. 2005); and *Cent. Ariz. WaterDist.* v. *EPA*, 990 F.2d 1531 (9th Cir. 1993).

expressly, as it did for the above-discussed CAA section 407(b)(2) NO_X requirements.

Second, the interpretations that commenters offer for these various provisions misapply the text. For example, commenters note that under CAA section 111(d)(1), (a)(3), and (a)(6), the standards of performance apply to "any existing source," and an "existing source" is defined to include "any stationary source," which, in turn, is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant." Commenters assert that these applicability and definitional provisions indicate that the BSER provisions in CAA section 111(d)(1) and (a)(1) must be interpreted to require that the control measures must be integrated into the design or operations of the source itself.

We disagree. These applicability and definitional provisions are jurisdictional in nature. Their purpose is simply to identify the types of sources whose emissions are to be addressed under CAA section 111(d), *i.e.*, stationary sources, as opposed to other types of sources, *e.g.*, mobile sources, whose emissions are addressed under other CAA provisions (such as CAA Title II). This purpose is made apparent by the terms of CAA section 111(a)(3), which contains two sentences (the second of which commenters seem to ignore). The first sentence provides: "The term 'stationary source' means any building, structure, facility, or installation which emits or may emit any air pollutant." The second sentence provides: "Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines." This second sentence explains that stationary internal combustion engines are to be regulated under CAA section 111, and not Title II (relating to mobile sources), which confirms that the purpose of the definition of stationary source is jurisdictional in nature—to identify the emissions that are to be regulated under section 111, as opposed to other CAA provisions.

These applicability and definitional provisions say nothing about the system of emission reduction—whether it is limited to measures integrated into the design or operation of the source itself or may be broader—that may form the basis of the standards for those emissions that are to be promulgated under CAA section 111.

Third, this argument by commenters does not account for the commonsense proposition that it is the owner/operator of the stationary source, not the source itself, who is responsible for taking actions to achieve the emission rate, so that actions that the owner/operator is able to take should be considered in determining the appropriate standards for the source's emissions. Again, it is common sense that buildings, structures, facilities, and installations can take no actions—only owners and operators can install and maintain pollution control equipment; only owners and operators can solicit precombustion cleaning or treatment of fuel services; and only owners and operators can apply for a permit or trade allowances.[507] Other provisions in CAA section 111

[507] Industry Commenters also acknowledged that it is the owner or operator that implements the control requirements. See UARG comment at 19 (section 111(d) "provides for the regulation of individual emission sources through performance standards

make clear the role of the owner/operator. CAA section 111(e) provides that for new sources, the burden of compliance falls on the "owner or operator."[508] The same is necessarily true for existing sources. This supports the EPA's view that the basis for whether a control measure qualifies as a "system of emission reduction" under CAA section 111(d)(1) and (a)(1) is whether it is something that the owner/operator can implement in order to achieve the emissions standard assigned to the source—if so, the control measure should qualify as a "system of emission reduction"—and not whether the control measure is integrated into the source's own design or operation.

Commenters also argue that CAA section 111(h), which authorizes "design, equipment, work practice or operational standard[s]" (together, "design standards") only when a source's emissions are not emitted through a conveyance or cannot be measured, makes clear that CAA section 111 standards of performance must be based on measures integrated into a source's own design or operations. We disagree. CAA section 111(h) concerns the relatively rare situation in which an emission standard, which entails a numerical limit on emissions, *is not* appropriate because emissions cannot be measured, due either to the nature of the pollutant (*i.e.*, the pollutant is not emitted through a conveyance) or the nature of the source category (*i.e.*,

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that are based on what design or process changes an individual source's owner can integrate into its facility").

[508] CAA section 111(e) provides: ("[I]t shall be unlawful for any owner or operator of any new source to operate such source in violation of any [applicable] standard of performance.")

the source category is not able to conduct measurements). CAA section 111(h) provides that in such cases, the EPA may instead impose design standards rather than establish an emission standard (*i.e.*, the EPA can require sources to implement a particular design, equipment, work practice, or operational standard). When an emissions standard *is* appropriate, as in the present rule, CAA section 111(h) is silent as to what types of measures—whether limited to a source's own design or operations—may be considered as the system of emission reduction.[509] In any event, CAA section 111(h) applies only to standards promulgated by the Administrator, and therefore appears by its terms to be limited to CAA section 111(b) rulemakings for new, modified, or reconstructed sources, not CAA section 111(d) rulemakings for existing sources.

Some commenters identify other provisions of CAA section 111 that, in their view, prove that CAA section 111 is limited to control measures that are integrated within the design or operations of the source. We do not find those arguments persuasive, for the reasons discussed in the supporting documents for this rule.

Commenters also argue, more generally, that Congress knew how to authorize control measures such as RE, as indicated by Congress's inclusion of those measures in Title IV (relating to acid rain), so

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[509] For this same reason, the fact that CAA section 111(h) authorizes the EPA to impose certain types of standards—such as, among others, work practice or operational standards—only in limited circumstances not present in this rulemaking, does not mean that the EPA cannot consider those same measures as the BSER in promulgating a standard of performance.

the fact that Congress did not explicitly include these measures in the BSER provisions of CAA section 111(d)(1) and (a)(1) indicates that Congress did not intend that they be included as part of the BSER, and instead intended that the BSER be limited to measures integrated into the sources' design or operations. This argument misses the mark. The provisions of CAA section 111(d)(1) and (a)(1) do not explicitly include *any* specific emission reduction measures—neither RE measures (like the ones Congress wanted to incentivize under Title IV), nor measures that are integrated into the sources' design or operations (like the retrofit control measures Congress required under CAA section 407(b)). But this contrast with other CAA provisions does not mean that Congress did not intend the BSER to include any of those types of measures. Rather, this contrast supports viewing a "system of emission reduction" under CAA section 111 as sufficiently broad to encompass a wide range of measures for the purpose of emission reduction of a wide range of pollutants from a wide range of stationary sources.[510]

c. *Deference to interpret the BSER to include building blocks 2 and 3.*

To the extent that it is not clear whether the phrase "system of emission reduction" may include the measures in building blocks 2 and 3, the EPA's

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[510] It should also be noted that Title IV is limited to particular pollutants (*i.e.*, SO_2 and NO_X) and particular sources—fossil fuel-fired EGUs—and as a result, lends itself to greater specificity about the types of control measures. Section 111(d), in contrast, applies to a wide range of source types, which, as discussed above, supports reading it to authorize a broad range of control measures.

interpretation of CAA section 111(d) and (a) is reasonable[511] in light of our discretion to determine "whether *and how* to regulate carbon-dioxide emissions from power plants . . . ."[512]

Our interpretation that a "system of emission reduction" for the affected EGUs may include building blocks 2 and 3 is a reasonable construction of the statute for the reasons described above and in this section below.

(1) *Consistency of building blocks 2 and 3 with the structure of the utility power sector.*

(a) *Integration of the utility power sector.*

Certain characteristics of the utility power sector are of central importance for understanding why the measures of building blocks 2 and 3 qualify as part of the system of emission reduction. As discussed above, electricity is highly substitutable and the utility power sector is highly integrated, so much so that it has been likened to a "complex machine."[513] Specifically, the utility power sector is characterized by physical, as well as operational, interconnections between electricity generators themselves, and between those generators and electricity users. Because of the physical properties of electricity and the current low availability of large scale electricity storage,

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[511] *EPA* v. *EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1603 (2014) ("We routinely accord dispositive effect to an agency's reasonable interpretation of ambiguous statutory language.").

[512] *American Electric Power Co.* v. *Connecticut*, 131 S. Ct. 2527, 2538 (2011) ("*AEP*") (emphasis added).

[513] S. Massoud Amin, "Securing the Electricity Grid," The Bridge, Spring 2010, at 13, 14; Phillip F. Schewe, The Grid: A Journey Through the Heart of Our Electrified World 1 (2007).

generation and load (or use) must be instantaneously balanced in real time. As a result, the utility power sector is uniquely characterized by extensive planning and highly coordinated operation. These features have been present for decades, and in fact, over time, the sector has become more highly integrated. Another important characteristics of the utility power sector is that although the states have developed both regulated and de-regulated markets, the generation of electricity reflects a least-cost dispatch approach, under which electricity is generated first by the generators with the lowest variable cost.

These characteristics of the sector have facilitated the overall objective of providing reliable electric service at least cost subject to a variety of constraints, including environmental constraints. Moreover, in each type of market, the sector has developed mechanisms, including the participation of institutional actors, to safeguard reliability and to assure least cost service.

Congress,[514] the Courts,[515] the EPA in its regulatory actions,[516] and states in their regulatory actions[517] have recognized the integrated nature of the utility power sector.

(b) *Significance of integrated utility power sector for the BSER.*

The fungibility of electricity, coupled with the integration of the utility power sector, means that, assuming that demand is held constant, adding electricity to the grid from one generator will result in the instantaneous reduction in generation from other generators. Similarly, reductions in generation from one generator lead to the instantaneous increase in generation from other generators. Thus, the operation of individual EGUs is integrated and coordinated with the operations of other EGUs and other sources of

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[514] *See* CAA section 404(f)(2)(B)(iii)(I) (conditioning a utility's eligibility for certain allowances on implementing an energy conservation and electric power plan that evaluates a range of resources to meet expected future demand at least cost); *see also* S. Rep. No. 101-228, at 319–20 (Dec. 20, 1989) (recognizing that "utilities already engage in power-pooling arrangements to ensure maximum flexibility and efficiency in supplying power" to support the establishment of an allowance system under Title IV).

[515] *New York* v. *Federal Energy Regulatory Commission*, 535 U.S. 1, at 7 (2002) (citing Brief for Respondent FERC 4–5).

[516] "Stack Heights Emissions Balancing Policy," 53 FR 480, 482 (Jan. 7, 1988).

[517] See 79 FR 34830, 34880 (June 18, 2014) (discussing State of California Global Warming Solutions Act of 2006, Assembly Bill 32, *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf*, and quoting December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy).

generation, as well as with electricity users. This allows for locational flexibility across the sector in meeting demand for electricity services. The institutions that coordinate planning and operations routinely use this flexibility to meet demand for electricity services economically while satisfying constraints, including environmental constraints. Because of these characteristics, EGU owner/ operators have long conducted their business, including entering into commercial arrangements with third parties, based on the premise that the performance and operations of any of their facilities is substantially dependent on the performance and operation of other facilities, including ones they neither own nor operate. For example, when an EGU goes off-line to perform maintenance, its customer base is served by other EGUs that increase their generation. Similarly, if an EGU needs to assure that it can meet its obligations to supply a certain amount of generation, it may enter into arrangements to purchase that generation, if it needs to, from other EGUs.

Because of this structure, fossil fuel-fired EGUs can reduce their emissions by taking the actions in building blocks 2 and 3. Specifically, fossil fuel-fired EGUs may generate or cause the generation of increased amounts of lower- or zero-emitting electricity—through contractual arrangements, investment, or purchase—which will back out higher-emitting generation, and thereby lower emissions. In addition, fossil fuel-fired EGUs may reduce their generation, which, given the overall emission limits this rule requires, will have the effect of stimulating lower- or zero-emitting generation.

It should also be noted that CO_2 is particularly well-suited for building blocks 2 and 3 because it is a global, not local, air pollutant, so that the location where it is emitted does not affect its environmental impact. The U.S. Supreme Court in the *UARG* case highlighted the importance of taking account of the unique characteristics of CO_2.[518]

In light of these characteristics of the utility power sector, as well as the characteristics of CO_2 pollution, it is reasonable for the EPA to reject an interpretation of the term "system of emission reduction" that would exclude building blocks 2 and 3 from consideration in this rule and instead restrict consideration to measures integrated into each individual affected source's design or operation, especially since the record and other publicly available information makes clear that the measures in the two building blocks are effective in reducing emissions and are already widely used.

As discussed above, no such restriction on the measures that can be considered part of a "system of emission reduction" is required by the statutory language, and the legislative history demonstrates that Congress intended an interpretation of the phrase broad enough to encompass building blocks 2 and 3. The narrow interpretation advocated by some commenters would permit consideration only of potential CO_2 reduction measures that are either more expensive than building blocks 2 and 3 (such as the use of natural gas co-firing at affected EGUs or the application of CCS technology) or measures capable of

[518] *See Util. Air. Reg. Group* v. *EPA*, 134 S. Ct. 2427, 2441 (2014).

achieving far less reduction in CO_2 emissions (such as the heat rate improvement measures included in building block 1). Imposing such a restrictive interpretation—one which is not called for by the statute—would be inconsistent with CAA section 111's specific requirement that standards be based on the "best" system of emission reduction and, as discussed below, would be inconsistent with Congressional design that the CAA be comprehensive and address the major environmental issues.[519]

The unique characteristics of the sector described above require coordinated action in the fundamental, primary function of EGUs—and in meeting current pollution control requirements to the extent that EGUs operate in dispatch systems that apply variable costs in determining dispatch—and affected EGUs necessarily already plan and operate on a multi-unit basis. In doing so, they already make use of building blocks 2 and 3 to meet operational and environmental objectives in a cost-effective manner, as further described below. CO_2 is a global pollutant that is exceptionally well-suited to emission reduction efforts optimized on a broad geographic scale rather than on a unit-by-unit basis. It is also clear from both comments and communications received through the Agency's outreach efforts that affected EGUs will seek to use building blocks 2 and 3 to achieve compliance with the emission standards set in the section 111(d) plans following promulgation of this rule. For these reasons—and the additional reasons discussed

[519] *See King* v. *Burwell*, No. 14-114 (2015) (slip op., at 21) ("But in every case we must respect the role of the Legislature, and take care not to undo what it has done.")

below—interpreting "system of emission reduction" so as to allow consideration in this rule of only the individual pieces of the "complex machine," and to forbid consideration of the ways in which the pieces actually fit and work together as parts of that machine, such as building blocks 2 and 3, cannot be justified. This is particularly so in light of the dilemma presented by the types of control options that commenters argue are the only ones authorized under section 111(a)(1), which are controls that apply to the design or operation of the affected EGUs themselves. On the one hand, the control measures in building block 1 yield only a small amount of emission reductions. On the other hand, control measures such as carbon capture and storage, or co-firing with natural gas, could yield much greater emission reductions, but are substantially more expensive than building blocks 2 and 3.

(2) *Current implementation of measures in building blocks 2 and 3.*

The requirement that the "system of emission reduction" be "adequately demonstrated" suggests that we begin our review under CAA section 111(d)(1) and (a)(1) with the systems that sources are already implementing to reduce their emissions. As noted above, fossil fuel-fired EGUs have long implemented, and are continuing to implement, the measures in building blocks 2 and 3 for various purposes, including for the purpose of reducing CO_2 emissions[520]—and

[520] A number of utilities have climate mitigation plans. Examples include National Grid, *http://www2.nationalgrid.com/responsibility/how-were-doing/grid-data-centre/climate-change/*; Exelon, *http://www.exeloncorp.com/newsroom/pr_20140423_EXC_Exelon2020*

certainly always with the effect of reducing emissions. This is a strong indicator that these measures should be considered part of a "system of emission reduction" for CO_2 emissions from these sources. The requirement that the "system of emission reduction" be "adequately demonstrated" indicates that the implementation of control mechanisms or other actions that the sources are already taking to reduce their emissions are of particular relevance in establishing the emission reduction requirements of CAA section 111(d)(1) and (a)(1). As a result, such measures are a logical starting point for consideration as a "system of emission reduction" under CAA section 111.

(3) *Reliance in CAA Title IV on building block measures.*

Some of the building block approaches to reducing emissions in the utility power sector were first tested around the time that Congress adopted the 1970 CAA Amendments.[521] Over time, these techniques have become more established within the industry, and by the 1990 CAA Amendments, Congress based the Title IV acid rain program for existing fossil fuel-fired

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.aspx; PG&E, *http://www.pge.com/about/environment/pge/climate/*; and Austin Energy, *http://austinenergy.com/wps/portal/ae/about/environment/austin-climate-protection-plan/!ut/p/a0/04_Sj9CPykssy0xPLMnMzOvMAfGjzOINjCyMPJwNjDzdzYOsDBzdnZ28TcP8DAMMDPQLshOVAU4fG7s!/*.

[521] *See, e.g.*, Shepard, Donald S., *A Load Shifting Model for Air Pollution Control in the Electric Power Industry*, Journal of the Air Pollution Control Association, Vol. 20:11, pp. 756–761 (November 1970).

EGUs in part on the same measures that are considered here.

(a) *Overview.*

It is logical that in determining whether the "system of emission reduction" that Congress established in CAA section 111(d)(1) and (a)(1) is broad enough to include the measures in building blocks 2 and 3 as the basis for establishing emission guidelines for fossil fuel-fired EGUs, an inquiry should be made into the tools that Congress relied on in other CAA provisions to reduce emissions from those same sources. The most useful CAA provision to examine for this purpose is Title IV, which includes a nationwide cap-and-trade program under which coal-fired power plants must have allowances for their SO_2 emissions.

Title IV includes several signals that it is especially relevant for interpreting and implementing CAA section 111(d) for purposes of this rule. Title IV applies to most of the same sources that this rule applies to—existing coal-fired EGUs and other utility boilers, as well as NGCC units. In addition, Congress added Title IV in the 1990 CAA Amendments at the same time that Congress largely reinstated the 1970-vintage reading of section 111(a)(1) to adopt the currently applicable definition of a "standard of performance," which is based on the "best system of emission reduction . . . adequately demonstrated." Moreover, Congress linked Title IV and CAA section 111 in certain respects. Specifically, Congress conditioned the revisions to CAA section 111(a)(1), *i.e.*, eliminating the percentage reduction and most of the other limitations under the 1977 CAA Amendments, on the continued applicability of the Title IV SO_2 cap, so that if the cap were eliminated, the changes would, by operation of law, also be eliminated, and the 1977 version of section 111(a)(1) would be reinstated.[522] Additionally, Congress authorized the EPA to establish standards of performance for new and existing industrial (non-EGU) sources of SO_2 emissions if emissions from these sources might exceed 1985 levels and failed to decline at the expected rate.[523] While industrial sources were not required to participate under Title IV—they could elect to do so, under CAA section 410(a)—Congress believed SO_2 reductions from these sources were "an essential component of the reductions sought under [Title IV]" and intended that Title IV would "assured that these projected reductions occur and will not be overcome by future growth in emissions."[524] As such, Congress viewed federal standards of performance as the

[522] 1990 CAA Amendments, §403, 104 Stat, at 2631 (requiring repeal of amendments to CAA section 111(a)(1) upon any cessation of effectiveness of CAA section 403(e), which requires new units to hold allowances for each ton of SO_2 emitted). Congress believed that mandating a technological standard through the percentage reduction requirement in section 111(a)(1) would ensure the continued availability of low sulfur coal for existing sources. In other words, the percentage reduction requirement discouraged compliance with new source performance standards based solely on fuel shifting because it was much more costly to achieve the percentage reduction with lower sulfur coal. This belief was expressed during the 1977 CAA Amendments and is discussed above as part of the legislative history of section 111.

[523] 1990 CAA Amendments, § 406, 104 Stat, at 2632–33; *see also* S. Rep. No. 101-228, at 282 (industrial source emissions totaled 5.6 million tons of SO_2 in 1985).

[524] S. Rep. No. 101-228, at 345 (Dec. 20, 1989).

appropriate backstop to Title IV even for sources that could not otherwise be regulated under CAA section 111(d).[525] Together, these signals suggest that it is reasonable for the EPA to consider Title IV when interpreting and implementing CAA section 111.

For present purposes, the essential features of Title IV are that it regulates SO_2 emissions from coal-fired EGUs by adopting a nationwide cap of 8.95 million tons to be achieved through a tradable allowance system. As we explain below, the provisions of Title IV and its legislative history make clear that Congress based the stringency of the emission limitation requirement (8.95 million tons) and the overall structure of the approach (a cap-and-trade system) on Congress's recognition that the affected EGUs had a set of tools available to them to reduce their emissions, including through a shift to lower emitting generation and use of RE, along with add-on controls and other measures. Thus, Title IV provides a close analogy to CAA section 111: Generation shift and RE were part of Congress's basis for the Title IV emission requirements, and that is analogous to building blocks 2 and 3 serving as part of the "system of emission reduction" that is the EPA's basis for the section 111(d) emission guidelines. For this reason, the fact that in Title IV, Congress relied on generation shift and RE as the basis for the SO_2 emission limitations for affected EGUs strongly supports interpreting CAA section 111(d)(1) and (a)(1) to include use of those same measures as part of the "system of emission

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[525] To reiterate, ordinarily, standards of performance cannot be used to regulate SO_2 emissions from existing sources because of the pollutant exclusions in CAA section 111(d).

reduction" as the basis for CO_2 emission limitations for those same sources.

(b) *Title IV provisions.*

Several provisions of Title IV make explicit Congress's reliance on some of the same measures as are in building blocks 2 and 3. Title IV begins with a statement of congressional "findings," including the finding that "strategies and technologies for the control of precursors to acid deposition exist now that are economically feasible, and improved methods are expected to become increasingly available over the next decade." CAA section 401(a)(4) (emphasis added). Title IV then identifies as its "purposes," "to reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide . . . and nitrogen oxides," as well as "to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this subchapter, for reducing air pollution and other adverse impacts of energy production and use." CAA section 401(b) (emphasis added).

By its terms, this statement of Title IV's purposes explicitly embraces the use of RE. Moreover, the legislative history makes clear that the reference in the "findings" section quoted above to "strategies and technologies" includes generation shift to lower-emitting generation. Specifically, the Senate Report stated that an "allowance system" [526] would encourage such "technologies and strategies" as

[526] *See* S. Rep. No. 101-228, at 320 (Dec. 20, 1989).

> energy efficiency; enhanced emissions reduction or control technologies—like sorbent injection, cofiring with natural gas, integrated gasification combined cycles; fuel-switching and *least-emissions dispatching* in order to maximize emissions reductions.[527]

Congress's reliance on generation shifting and RE to reduce acid rain precursors from affected EGUs in Title IV strongly supports the EPA's authority to identify those same measures as part of the CAA section 111 "system of emission reduction" to reduce CO_2 emissions from those same sources.

In addition, Title IV includes other provisions expressly concerning RE. In CAA section 404(f) and (g), Congress set aside a special pool of allowances to encourage use of RE. In order to obtain a special allowance (which would authorize emissions from a coal-fired utility), an electric utility needed to pay for qualifying RE sources "directly or through purchase from another person."[528] These measures confirm Congress's recognition that RE was available to the industry, was desirable to encourage from a policy perspective, and was appropriate to consider in determining the amount of pollution reduction the law should require.

(c) *Title IV legislative history.*

Numerous statements in the legislative history confirm that Congress based the Title IV requirements on the fact that affected EGUs could reduce their SO_2

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[527] *See* S. Rep. No. 101-228, at 316 (Dec. 20, 1989) (emphasis added).

[528] CAA section 404(f)(2)(B)(i).

emissions through a set of measures, including shifting to lower-emitting generation as well as reliance on RE.

For example, the Senate Committee Report[529] and Senator Baucus, [530] a member of the Senate Committee on Environment and Public Works and Chairman of the House and Senate Clean Air Conferees, both emphasized that affected EGUs could rely on, among other things, "least-emissions dispatching in order to maximize emissions reductions." Similarly, statements supporting the RE reserve were included in the legislative history on the House side.

> We believe that this provision of the bill will establish a balanced and workable approach that will provide certainty for utility companies that are considering conservation and renewables, while at the same time strengthening the environmental goals of this legislation.[531]

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[529] S. Rep. No. 101-228 (Dec. 20, 1989), 1990 CAA Legis. Hist. at 8656.

[530] S. Debates on Conf. Rep. to accompany S. 1630, H.R. Rep. No. 101-952 (Oct. 27, 1990), 1990 CAA Legis. Hist. at 1033–35 (statement of Senator Baucus, inserting "the Clean Air Conference Report" into the record).

[531] H.R. Rep. No. 101-490, at 368–69; 674–76 (May 17, 1990) (additional views of Reps. Markey and Moorhead) ("We believe that H.R. 3030, as amended, will create a strong and effective incentive for utilities to immediately pursue energy conservation and renewable energy sources as key components of their acid rain control strategies."); *see also* Rep. Collins, H. Debates on H.R. Conf. Rep. No. 101-952 (Oct. 26, 1990), 1990 CAA Legis. Hist. at 1307 ("The bottom line is that our Nation's utilities and production facilities must reach beyond coal, oil, and fossil fuels. The focus must shift instead toward conservation and renewables

(4) *Reliance on RE measures to reduce CO_2.*

The Title IV legislative history also makes clear that Congress viewed RE measures as a means to reduce CO_2 for the purpose of mitigating climate change. By the time of the 1990 CAA Amendments, Congress had long been aware that emissions of CO_2 and other GHGs put upward pressure on world temperatures and threatened to change the climate in destructive ways. In 1967, President Lyndon Johnson sent a letter to Congress recognizing that carbon dioxide was changing the composition of the atmosphere.[532] The record for the 1970 CAA Amendments include hearings[533] and a report by the National Academy of Sciences noting that carbon dioxide emissions could heat the atmosphere.[534] A 1976 report noting the

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such as hydropower, solar thermal, photovoltaics, geothermal, and wind. These clean sources and energy, available in virtually limitless supply, are the way of the future.").

[532] "Special Message to the Congress on Conservation and Restoration of Natural Beauty (Feb. 8, 1965). *http://www.presidency.ucsb.edu/ws/?pid=27285* ("This generation has altered the composition of the atmosphere on a global scale through radioactive materials and a steady increase in carbon dioxide from the burning of fossil fuels.").

[533] Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381 (stating that "the carbon dioxide balance might result in the heating up of the atmosphere whereas the reduction of the radiant energy through particulate matter released to the atmosphere might cause reduction in radiation that reaches the earth").

[534] 1970 CAA Legis. Hist. at 244, 257 S. Debate on S. 4358 (Sept. 21, 1970) (statement of Sen. Boggs) (replicating Chapter IV of the Council on Environmental Quality's first annual report,

phenomenon was included in the record for the 1977 CAA Amendments.[535] A 1977 Report by the National Academy of Sciences warned that average temperatures would rise due to the burning of fossil fuel.[536] By the time of the 1990 CAA Amendments, the dangers had become more clearly evident. Senate hearings beginning in 1988 had presented testimony from Dr. James E. Hansen of the National Aeronautics and Space Administration and other scientists that described the dangers of climate change caused by anthropogenic carbon dioxide and other GHG emissions and asserted that as a result of those emissions, the climate was in fact already changing.[537]

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which states, "the addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate.").

[535] 122 Cong Rec S25194 (daily ed Aug. 3, 1976) (statement of Sen. Bumpers) (inserting into the record, "Summary of Statements Received from Professional Societies for the Hearings on Effects of Chronic Pollution (in the Subcommittee on the Environment and the Atmosphere)," which stated, "there is near unanimity that carbon dioxide concentrations in the atmosphere are increasing rapidly. Though even the direction (warming or cooling) of the climate change to be caused by this is unknown, very profound changes in the balance of climate factors that determine temperature and rainfall on the earth are almost certain within 100 years").

[536] National Academy of Sciences, "Energy and Climate: Studies in Geophysics" viii (1977), *http://www.nap.edu/openbook.php?record_id=12024* (noting that a fourfold to eightfold increase in carbon dioxide by the latter part of the twenty-second century would increase average world temperature by more than 6 degrees Celsius).

[537] S. Rep. No. 101-228, at 322 (Dec. 20, 1989), at 1990 Legis. Hist. at 8662 ("In the last several years, the Committee has received extensive scientific testimony that increases in the

In enacting the 1990 CAA Amendments, Congress identified reductions in carbon dioxide emissions as an important co-benefit of the reductions in coal use and stressed that the RE measures would achieve those reductions. Senator Fowler, the author of the provision that established a RE technology reserve within the allowance system, noted that RE technologies, "can greatly reduce emissions of . . . global warming gases. That makes them a potent weapon against catastrophic climate change . . . ."[538]

In addition, the 1990 CAA Amendments required EGUs covered by the monitoring requirements of the Title IV acid rain program to report their CO_2 emissions.[539]

(5) *Other EPA actions that rely on the building block measures.*

Another indication that it is reasonable to interpret the CAA section 111(d)(1) and (a)(1) provisions for the BSER to include the measures in building blocks 2 and 3 is that the EPA and states have relied on these measures to reduce emissions in a number of other CAA actions.

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human-caused emissions of carbon dioxide and other GHGs will lead to catastrophic shocks in the global climate system."); History, Jurisdiction, and a Summary of Activities of the Committee on Energy and Natural Resources During the 100th Congress, S. Rep. No. 101-138, at 5 (Sept. 1989); "Global Warming Has Begun, Expert Tells Senate," New York Times, June 24, 1988, *http://www.nytimes.coin/1988/06/24/us/gIobaI-warining-has-begun-expert-tells-senate.html.*

[538] Sen. Fowler, S. Debate on S. 1630 (Apr. 3, 1990), 1990 CAA Legis. Hist. at 7106.

[539] 1990 CAA Amendments, § 821, 104 Stat. at 2699.

For example, in 2005, the EPA promulgated a rule to control mercury emissions from fossil fuel-fired power plants under section 111(d): The Clean Air Mercury Rule (CAMR).[540] The EPA established a nationwide cap-and-trade program that took effect in two phases: In 2010, the cap was set at 38 tons per year, and in 2018, the cap was lowered to 15 tons per year. The EPA expected, on the basis of modeling, that sources would achieve the second phase, 15-ton per year cap cost-effectively by choosing among a set of measures that included shifting generation to lower-emitting units.[541] CAMR was vacated by the D.C. Circuit on other grounds,[542] but it shows that in the only other section 111(d) rule that the EPA attempted for affected EGUs, the EPA relied on shifting generation as part of the BSER in a CAA section 111(d) rulemaking for fossil fuel-fired EGUs.

In 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR),[543] in which it set statewide emission budgets for NO_X and SO_2 emitted by fossil fuel-fired EGUs, and based those standards in part on

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[540] 70 FR 28606 (May 18, 2005).

[541] 70 FR 28606, 28619 (May 18, 2005) ("Under the CAMR scenario modeled by EPA, units [were] projected to meet their SO_2 and NO_X requirements and take additional steps to address the remaining [mercury] reduction requirements under CAA section 111, including adding [mercury]-specific control technologies (model applies [activated carbon injection]), additional scrubbers and [selective catalytic reduction], *dispatch changes*, and coal switching.").

[542] *New Jersey* v. *EPA*, 517 F.3d 574, 583–84 (D.C. Cir. 2008), *cert. denied sub nom. Util. Air Reg. Group* v. *New Jersey*, 555 U.S. 1169 (2009).

[543] 76 FR 48208 (Aug. 8, 2011).

shifts to lower-emitting generation. CSAPR established state-wide emissions budgets based on a range of cost-effective actions that EGUs could take, and set the stringency of the deadlines for some required reductions in part because of the availability of "increased dispatch of lower-emitting generation which can be achieved by 2012." [544] The EPA developed a federal implementation plan (FIP) that established a trading program to meet the state-wide emission budgets set by CSAPR. The EPA projected that sources would meet their emission reduction obligations by implementing a range of emission control approaches, including the operation of add-on controls, switches to lower-emitting coal, and "changes in dispatch and generation shifting from higher emitting units to lower emitting units."[545] The U.S.

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[544] 76 FR at 48452.

[545] 76 FR at 48279–80. The exact mix of controls varied for different air pollutants and different time periods, but in all cases, shifting generation from higher to lower emitting units was one of the expected control strategies for the fossil fuel-fired power plants. Prior to CSAPR, the EPA promulgated two other transport rules, the NO_X SIP Call (1998) and the Clean Air Interstate Rule (CAIR) (2005), which similarly established standards based on analysis of the availability and cost of emission reductions achievable through the use of add-on controls and generation shifting, and also authorized and encouraged the implementation of RE and demand-side EE measures. CAIR: 70 FR 25162, 25165, 25256, 25279 (May 12, 2005) (allowing use of allowance set-asides for renewables and energy efficiency); NO_X SIP Call: 63 FR 57356, 57362, 57436, 57438, 57449 (Oct. 27, 1998) (authorizing and encouraging SIPs to rely on renewables and energy efficiency to meet the state budgets).

Supreme Court upheld CSAPR in *EPA* v. *EME Homer City Generation, L.P.*[546]

With respect to RE, in 2004, the EPA provided guidance to states for adopting attainment SIPs under CAA section 110 that include RE measures.[547] Some states have done so. For example, Connecticut included in its SIP reductions from solar photovoltaic installations.[548] In 2012, the EPA provided additional guidance on this topic.[549] In addition, the EPA has partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including RE in a SIP and to provide real-world examples and lessons learned through those states' case studies.[550]

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[546] 134 S. Ct. 1584 (2014).

[547] *See, e.g.*, Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/tl/memoranda/ereseerem_gd.pdf*; Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf*.

[548] CT 1997 8-hour ozone SIP Web site, *http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619* (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

[549] "Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs" (July 2012), *http://epa.gov/airquality/eere/manual.html*.

[550] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013),

(6) *Other rules that relied on actions by other entities.*

The EPA has promulgated numerous actions that establish control requirements for affected sources on the basis of actions by other entities or actions other than measures integrated into the design or operations of the affected sources. This section summarizes some of those actions. First, virtually all pollution control requirements require the affected sources to depend in one way or another on other entities, such as control technology manufacturers. Second, the EPA has promulgated numerous regulatory actions that are based on trading of mass-based emission allowances or rate-based emission credits, in which many sources meet their emission limitation requirements by purchasing allowances or credits from other sources that reduce emissions.

(a) *Third-party transactions.*

To reiterate, commenters argue that the "system of emission reduction" must be limited to measures taken by the affected source itself because only those measures are under the control of the affected source, as opposed to third parties, and therefore only those measures can assure that the affected source will achieve its emission limits. But this argument is belied by the fact that for a wide range of pollution control measures—including many that are indisputably part of a "system of emission reduction"—affected sources are in fact dependent on third parties. For example, to implement any type of

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http://www.nescaum.org/documents/nescaum-final-rept-to-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf.

add-on pollution control equipment that is available only from a third-party manufacturer, the affected source is dependent upon that third party for developing and constructing the necessary controls, and for offering them for sale. Indeed, the affected sources may be dependent upon third parties to install (and in some cases to operate) the controls as well, and in fact, in the CAIR rule, the EPA established the compliance date based on the limited availability of the specialized workforce needed to install the controls needed by the affected EGUs.[551] In addition, EGU owners and operators may be dependent on the actions of third parties to finance the controls and third-party regulators to assure the mechanism for repaying that financing. However, this dependence does not mean that the emission limit based on that equipment is not achievable. Rather, the fact that the owner or operator of the affected source can arrange with the various third parties to acquire, install, and pay for the equipment means that emission limit is achievable.

In this rule, as noted, the affected EGUs may, in many cases, implement the measures in building blocks 2 and 3 directly, and, in other cases, implement those measures by engaging in market transactions with third parties that are as much within the affected EGUs' control as engaging in market transactions with the range of third parties involved in pollution control equipment. By the same token, the market transactions that the affected EGUs engage in with third parties to implement the measures in building

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[551] 70 FR 25162, 25216–25225 (May 12, 2005). The EPA noted that its view was "based on the NO_X SIP Call experience." *Id.* at 25217.

blocks 2 and 3 are comparable to the market transactions that affected EGUs engage in as part of their normal course of business, which include, among many examples, transactions with RTOs/ISOs or balancing authorities, entities in organized markets.

(b) *Emissions trading.*

Additional precedent that the "system of emission reduction" may include the measures in building blocks 2 and 3 and is not limited to measures that a source can integrate into its own design or operations, without being dependent on other entities, is found in the many rules that Congress has enacted or that the EPA has promulgated that allow EGUs and other sources to meet their emission limits by trading with other sources. In a trading rule, the EPA authorizes a source to meet its emission limit by purchasing mass-based emission allowances or rate-based emission credits generated from other sources, typically ones that implement controls that reduce their emissions to the point where they are able to sell allowances or credits. As a result, the availability of trading reduces overall costs to the industry by focusing the controls on the particular sources that have the least cost to implement controls. For present purposes, what is relevant is that in a trading program, some affected sources choose to meet their emission limits not by implementing emission controls integrated into their own design or operations, but rather by purchasing allowances or credits. These affected sources, therefore, are dependent on the actions of other entities, which are the ones that choose to meet their emission limits by implementing emission controls, which permits them to sell allowances or credits. They are dependent, however, in the same way that a source acquiring pollution control technology for the purposes of meeting a NSPS is dependent on a vendor of that technology to fulfill its contractual obligations. That is, the source operator purchasing a credit or an allowance is acquiring an equity in the technology or action applied to the credit-selling source for purposes of achieving a reduction in emissions occurring at the selling source. Trading programs have been commonplace under the CAA, particularly for EGUs, for decades. They include the acid rain trading program in Title IV of the CAA, the trading programs in the transport rules promulgated by the EPA under the "good neighbor provision" of CAA section 110(a)(2)(D)(i)(I), the Clean Air Mercury Rule, and the regional haze rules. In each of these actions, the Congress or the EPA recognized that some of the affected EGUs would implement controls or take other actions that would lower their emissions and thereby allow them to sell allowances to other EGUs, which were dependent on the purchase of those allowances to meet their obligations.[552] For the reasons just

[552] For example, in the enacting the acid rain program under CAA Title IV, Congress explicitly recognized that some sources would comply by purchasing allowances instead of implementing controls. S. Rep. No. 101-228, at 303 (Dec. 20, 1989). Similarly, in promulgating the NO_X SIP Call in 1998, the EPA stated, "Since EPA's determination for the core group of sources is *based on the adoption of a broad-based trading program*, average cost-effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs." 63 FR at 57399 (emphasis added). By the same token, in promulgating the Cross State Air Pollution Rule, the EPA stated, "the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost effective manner, such as installing controls, changing

described, these trading rules refute commenters' arguments for limiting the scope of the "system of emission reduction."

(c) *NSPS rules for EGUs that depend on the integrated grid.*

The EPA has promulgated NSPS for EGUs that include requirements based on the fact that an EGU may reduce its generation, and therefore its emissions, because the integration of the grid allows another EGU to increase generation and thereby avoid jeopardizing the supply of electricity. For example, in 1979, the EPA finalized new standards of performance to limit emissions of SO_2 from new, modified, and reconstructed EGUs. In evaluating the best system against concerns of electric service reliability, the EPA took into account the unique features of power transmission along the interconnected grid and the unique commercial relationships that rely on those features.[553]

Additionally, in 1982, the EPA recognized that utility turbines could meet a NO_X emission limit without unacceptable economic consequences because "other electric generators on the grid can restore lost

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fuels, reducing utilization, *buying allowances*, or any combination of these actions." 76 FR at 48272 (emphasis added).

[553] *See* 44 FR 33580, 33597–33600 (taking into account "the amount of power that could be purchased from neighboring interconnected utility companies" and noting that "[a]lmost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations" and that "load can usually be shifted to other electric generating units").

capacity caused by turbine down time."[554] We describe the relevant parts of these rules in greater detail in the Legal Memorandum.

(7) *Consistency with the purposes of the Clean Air Act.*

Interpreting the term "system of emission reduction" broadly to include building blocks 2 and 3 (so that the "best system of emission reduction . . . adequately demonstrated" may include those measures as long as they meet all of the applicable requirements) is also consistent with the purposes of the CAA. Most importantly, these purposes include protecting public health and welfare by comprehensively addressing air pollution, and, particularly, protecting against urgent and severe threats. In addition, these purposes include promoting pollution prevention measures, as well as the advancement of technology that reduces air pollution.

(a) *Purpose of protecting public health and welfare.*

The first provisions in the Clean Air Act set out the "Congressional findings and declaration of purpose." CAA section 101. CAA section 101(a)(2) states the finding that "the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, has resulted in mounting dangers to the public health and welfare." CAA section 101(a)(3) states the finding that "air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the

[554] 47 FR 3767, 3768 (Jan. 27, 1982).

primary responsibility of States and local governments." CAA section 101(a) states the finding that "Federal financial assistance and leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution."

CAA section 101(b) next states "[t]he purposes" of the Clean Air Act. The first purpose is "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." CAA section 101(b)(1). The second is "to initiate and accelerate a national research and development program to achieve the prevention and control of air pollution." CAA section 101(b)(2). The third is "to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs." CAA section 101(b)(3). The fourth is "to encourage and assist the development and operation of regional air pollution prevention and control programs." CAA section 101(c) adds that "[a] primary goal of this Act is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this Act, for pollution prevention."

As just quoted, these provisions are explicit that the purpose of the CAA is "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." Moreover, Congress designed the CAA to be "the comprehensive vehicle for protection of the Nation's health from air pollution" [555] and, in fact, designed CAA section 111(d) to address air pollutants not covered under other provisions, specifically so that "there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare." [556] Furthermore, in these purpose provisions, Congress recognized that while pollution prevention and control are the primary responsibility of the States, "federal leadership" would be essential.

At its core, Congress designed the CAA to address urgent and severe threats to public health and welfare. This purpose is evident throughout 1970 CAA Amendments, which authorized stringent remedies that were necessary to address those problems. By 1970, Congress viewed the air pollution problem, which had been worsening steadily as the nation continued to industrialize and as automobile travel dramatically increased after World War II, [557] as nothing short of a national crisis.[558] With the 1970

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[555] H.R. Rep. No. 95-294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring the EPA to study and regulate radioactive air pollutants and three other air pollutants).

[556] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)).

[557] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945–1970* (Texas A&M University Press 2000).

[558] 1970 was a significant year in environmental legislation, but it was also marked as "a year of environmental concern." Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 223. By mid-1970, Congress recognized that "[o]ver 200 million tons of contaminants [were] spilled into the air each year

CAA Amendments, Congress enacted a stringent response, designed to match the severity of the problem. At the same time, Congress did not foreclose the EPA's ability to address new environmental concerns; in fact, Congress largely deferred to the EPA's expertise in identifying pollutants and sources that adversely affect public health or welfare. In doing so, Congress authorized the EPA to establish national ambient air quality standards for the most pervasive air pollutants—including the precursors for the choking smog that blanketed urban areas[559]—to protect public health with an ample margin of safety. Disappointed that the states had not taken effective action to that point to curb air pollution, "Congress

in America . . . . And each year these 200 million tons of pollutants endanger the health of [the American] people." Id. at 224. "Cities up and down the east coast were living under clouds of smog and daily air pollution alerts." Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 124. Put simply, America faced an "environmental crisis." Sen. Muskie, S. Debate on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 224. The conference agreement, it was reported, "faces the air pollution crisis with urgency and in candor. It makes hard choices, provides just remedies, requires stiff penalties." Sen. Muskie, S. Consideration of the Conference Rep. (Dec. 18, 1970), 1970 CAA Legis. Hist. at 123. "[I]t represents [Congress'] best efforts to act with the knowledge available . . . in an affirmative but constructive manner." *Id.* at 150.

[559] *See* Dewey, Scott Hamilton, *Don't Breathe the Air: Air Pollution and U.S. Environmental Politics, 1945–1970* (Texas A&M University Press 2000) at 230 ("By the mid-1960s, top federal officials showed an increasing sense of alarm regarding the health effects of polluted air. In June, 1966, Secretary of Health, Education, and Welfare John W. Gardner testified before the Muskie subcommittee: "We believe that air pollution at concentrations which are routinely sustained in urban areas of the United States is a health hazard to many, if not all, people.").

reacted by taking a stick to the States"[560] and including within the 1970 CAA Amendments both the requirement that the states develop plans to assure that their air quality areas would meet those standards by no later than five years, and the threat of imposition of federal requirements if the states did not timely adopt the requisite plans. Congress also required the EPA to establish standards for hazardous air pollutants that could result in shutting sources down. Congress added stringent controls on automobiles, overriding industry objections that the standards were not achievable. In addition, Congress added CAA section 111(b), which required the EPA to list categories based on harm to public health and regulate new sources in those categories. Congress then designed CAA section 111(d) to assure, as the Senate Committee Report for the 1970 CAA Amendments noted, that "there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."[561]

Similarly, the 1977 and 1990 CAA Amendments were also designed to respond to new and/or pressing environmental issues. For example, in 1977 then-EPA

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[560] *Train* v. *NRDC*, 421 U.S. 60, 64 (1975).

[561] S. Rep. No. 91-1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95-294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to study and then take action to regulate radioactive air pollutants and three other air pollutants).

Administrator Costle testified before Congress that the expected increase in coal use (in response to various energy crises, including the 1973–74 Arab Oil Embargo) "will make vigorous and effective control even more urgent."[562] Similarly, by 1990, Congress recognized that "many of the Nation's most important air pollution problems [had] failed to improve or [had] grown more serious."[563] Indeed, President George H. W. Bush said that " 'progress has not come quickly enough and much remains to be done.' "[564]

Climate change has become the nation's most important environmental problem. We are now at a critical juncture to take meaningful action to curb the growth in CO_2 emissions and forestall the impending consequences of prior inaction. CO_2 emissions from existing fossil fuel-fired power plants are by far the largest source of stationary source emissions. They emit almost three times as much CO_2 as do the next nine stationary source categories combined, and

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[562] Statement of Administrator Costle, Hearings before the Subcommittee on Energy Production and Supply of the Senate Committee on Energy and Natural Resources (Apr. 5, 7, May 25, June 24 and 30, 1977), 1977 CAA Legis. Hist. at 3532 (discussing the relationship between the National Energy Plan and the Administration's proposed CAA amendments). Some of the specific changes to the CAA include the addition of the PSD program, visibility protections, requirements for nonattainment areas, and stratospheric ozone provisions.

[563] H.R. Rep. No. 101-490, at 144 (May 17, 1990).

[564] H.R. Rep. No. 101-490, at 144 (May 17, 1990). Some of the changes adopted in 1990 include revisions to the NAAQS nonattainment program, a more aggressive and substantially revised CAA section 112, the new acid rain program, an operating permits program, and a program for phasing out of certain ozone depleting substances.

approximately the same amount of CO_2 emissions as all of the nation's mobile sources. The only controls available that can reduce CO_2 emissions from existing power plants in amounts commensurate with the problems they pose are the measures in building blocks 2 and 3, or far more expensive measures such as CCS.

Thus, interpreting the "system of emission reduction" provisions in CAA section 111(d)(1) and (a)(1) to allow the nation to meaningfully address the urgent and severe public health and welfare threats that climate change pose is consistent with what the CAA was designed to do.[565] This interpretation is also consistent with the cooperative purpose of section 111(d) to assure that the CAA comprehensively address those threats through the mechanism of state plans, where the states assume primary responsibility under federal leadership. *See King* v. *Burwell*, 576 U.S. (2015), No. 14-114 (2015), slip op. at 15 ("We

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[565] In addition, as we have noted, in designing the 1970 CAA Amendments, Congress was aware that carbon dioxide increased atmospheric temperatures. In 1970, when Congress learned that "the carbon dioxide balance might result in the heating up of the atmosphere" and that particulate matter "might cause reduction in radiation," the Nixon Administration assured Congress that "[w]hat we are trying to do, however, in terms of our air pollution effort should have a very salutary effect on either of these." Testimony of Charles Johnson, Jr., Administrator of the Consumer Protection and Environmental Health Service (Administration Testimony), Hearing of the House Subcommittee on Public Health and Welfare (Mar. 16, 1970), 1970 CAA Legis. Hist. at 1381. Many years later, scientific consensus has formed around the particular causes and effects of climate change; and the tools put in place in 1970 can be read fairly to address these concerns.

cannot interpret federal statutes to negate their own stated purposes" (quoting *New York State Dept. of Social Servs.* v. *Dublino*, 413 U.S. 405, 419–20 (1973)); i*d*. at 21 ("A fair reading of legislation demands a fair understanding of the legislative plan.").[566]

(b) *Purpose of encouraging pollution prevention.*

Interpreting "system of emission reduction" to include building blocks 2 and 3 is also consistent with the CAA's purpose to encourage pollution prevention. CAA section 101(c) states that "[a] primary goal of [the CAA] is to encourage or otherwise promote reasonable federal, state, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention." Indeed, in the U.S. Code, in which the CAA is codified as chapter 85, the CAA is

[566] This final rule is also consistent with the CAA's purpose of protecting health and welfare. For example, the CAA authorizes the EPA to regulate air pollutants as soon as the EPA can determine that those pollutants pose a risk of harm, and not to wait until the EPA can prove that those pollutants actually cause harm. *See* H.R. Rep. No. 95-294, at 49 (May 12, 1977), 1977 CAA Legis. Hist. at 2516 (describing the CAA as being designed . . . to assure that regulatory action can effectively prevent harm before it occurs; to emphasize the predominant value of protection of public health"). The protective spirit of the CAA extends to the present rule, in which the EPA regulates on the basis of building blocks 2 and 3 because the range of available and cost-effective measures in those building blocks achieves more pollution reduction than building block 1 alone. Indeed, add-on controls that are technically capable of reducing CO_2 emissions at the scale necessitated by the severity of the environmental risk—for example, CCS technology—are not as cost-effective as building blocks 2 and 3 on an industry-wide basis, and while the costs of the add-on controls can be expected to be reduced over time, it is not consonant with the protective spirit of the CAA to wait.

entitled, "Air Pollution Prevention and Control." [567] CAA section 101(a)(3) describes "air pollution prevention" as "the reduction or elimination, through *any* measures, of the amount of pollutants produced or created at the source". (Emphasis added.) The reference to "any measures" highlights the breadth of what Congress considered to be pollution prevention, that is, any and all measures that reduce or eliminate pollutants at the source.[568]

The measures in building blocks 2 and 3 qualify as "pollution prevention" measures because they are "any measures" that "reduc[e] or eliminate[e] . . . the amount of pollutants produced or created at the [fossil fuel-fired affected] source[s]." Thus, consistent with the CAA's primary goals, it is therefore reasonable to interpret a "system of emission reduction," as including the pollution prevention measures in building blocks 2 and 3.

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[567] *See* Air Quality Act of 1967, Pub. L. 90-148, § 2, 81 Stat. 485 (Nov. 21, 1967) (adding "Title I—Air Pollution Prevention and Control" to the CAA, along with Congress' initial findings and purposes under CAA section 101).

[568] Section 101 emphasizes the importance of air pollution prevention in two other provisions: CAA section 101(b)(4) states that one of "the purposes of [title I of the CAA, which includes section 111] are . . . (b) to encourage and assist the development and operation of regional air pollution prevention and control programs." CAA section 101(a)(3) adds: "The Congress finds—. . . (3) that air pollution prevention . . . and air pollution control at its source is the primary responsibility of states and local governments." In fact, section 101 mentions pollution prevention no less than 6 times.

(c) *Purpose of advancing technology to control air pollution.*

This final rule is also consistent with CAA section 111's purpose of promoting the advancement of pollution control technology based on the expectation that American industry will be able to develop innovative solutions to the environmental problems.

The legislative history and case law of CAA section 111 identify three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the "best system of emission reduction . . . adequately demonstrated;" under CAA section 111(a)(1); [569] (ii) the expanded use of the best demonstrated technology; [570] and (iii) the development of emerging technology.[571] This rule is consistent with the second of those ways—it expands the use of the measures in building blocks 2 and 3, which are already established and provide substantial reductions at reasonable cost. As discussed below, the use of the measures in these building blocks will be most fully expanded when organized markets develop, and our expectation that those markets will develop is

[569] *See Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must "look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present").

[570] *See* S. Rep. No. 91-1196, at 15 ("The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems").

[571] *See Sierra Club* v. *Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

consistent with the Congress's view, just described, that CAA section 111 should promote technological innovation.

This final rule is also consistent with Congress's overall view that the CAA Amendments as a whole were designed to promote technological innovation. In enacting the CAA, Congress articulated its expectation that American industry would be creative and come up with innovative solutions to the urgent and severe problem of air pollution. This is manifest in the well-recognized technology-forcing nature of the CAA, and was expressed in numerous, sometimes ringing, statements in the legislative history about the belief that American industry will be able to develop the needed technology. For example, in the 1970 floor debates, Congress recalled that the nation had put a man on the moon a year before and had won World War II a quarter century earlier, and attributed much of the credit for those singular achievements to American industry and its ability to be productive and innovative. Congress expressed confidence that American industry could meet the challenges of developing air pollution controls as well.[572]

[572] Sen. Muskie, S. Debates on S. 4358 (Sept. 21, 1970), 1970 CAA Legis. Hist. at 227 ("At the beginning of World War II industry told President Roosevelt that his goal of 100,000 planes each year could not be met. The goal was met, and the war was won. And in 1960, President Kennedy said that America would land a man on the moon by 1970. And American industry did what had to be done. Our responsibility in Congress is to say that the requirements of this bill are what the health of the Nation requires, and to challenge polluters to meet them."). *See* Blaime, A.J., *The Arsenal of Democracy: FDR, Detroit, and an Epic Quest to Arm an America at War* (Houghton Mifflin Harcourt 2014); Carew, Michael G., *Becoming the Arsenal: The American*

(d) *Response to commenters concerning purpose.*

Commenters have stated that the proposed rule "would transform CAA section 111 into something untethered to its statutory language and unrecognizable to the Congress that created it."[573] Commenters with this line of comments focused on the ramifications of building block 4, which the EPA has decided does not belong in BSER using EPA's historical interpretation of BSER. Regardless of whether the comments are accurate with respect to building block 4 measures, they are certainly not accurate with respect to the three building blocks that the EPA is defining as the BSER. This rule would be recognizable to the Congresses that created and amended CAA section 111 and is carefully fashioned to the statutory text in CAA section 111(d) and (a)(1). This final rule would be recognizable to the Congress that adopted CAA section 111 in 1970 as part of a bold, far-reaching law designed to address comprehensively an air pollution crisis that threatened the health of millions of Americans; to have EPA and the States work cooperatively to develop state-specific approaches to address a national problem; to challenge industry to meet that crisis with creative energy; and to give the EPA broad authority—under section 111 and other provisions—to craft the needed emission limitations. This final rule would be recognizable to

Industrial Mobilization for World War II, 1938–1942 (University Press of America, Inc. 2010).

[573] UARG comment at 31. *See id*. at 18, 29, 49. This comment appears to be a reference to the Supreme Court's statement in *UARG*. *See Util. Air Reg. Group* v. *EPA*, 134 S. Ct. 2427, 2444 (2014).

the Congress that revised CAA section 111 in 1977 to explicitly authorize that standards be based on actions taken by third parties (fuel cleaners). And this final rule would be recognizable to the Congress that revised CAA section 111 in 1990 to be linked to the Acid Rain Program that Congress adopted at the same time, which regulated the same industry (fossil fuel-fired EGUs) through some of the same measures (generation shifts and RE), and that explicitly acknowledged that those measures (RE) would also reduce CO_2 and thereby address the dangers of climate change. To reiterate, for the reasons explained in this preamble, this rule is grounded in our reasonable interpretation of CAA section 111(d) and (a)(1).

(8) *Constraints on the BSER—treatment of building block 4 and response to comments concerning precedents.*

Although the BSER provisions are sufficiently broad to include, for affected EGUs, the measures in building blocks 2 and 3, they also incorporate significant constraints on the types of measures that may be included in the BSER. We discuss those constraints in this section. These constraints explain why we are not including building block 4 in the BSER. In addition, these constraints explain why our reliance on building blocks 2 and 3 will have limited precedential effect for other rulemakings, and serve as our basis for responding to commenters who expressed concern that reliance on building blocks 2 and 3 would set a precedent for the EPA to rely on similar measures in promulgating future air pollution controls for other sectors.[574]

As discussed above, the emission limits in the CAA section 111(d) emission guidelines that this rule promulgates are based on the EPA's determination, for the affected EGUs, of the "system of emission reduction" that is the "best," taking into account "cost" and other factors, and that is "adequately demonstrated." Those components include certain interpretations and applications and provide constraints on the types of measures or controls that the EPA may determine to include in the BSER.

(a) *Emission reductions from affected sources.*

The first constraint is that the BSER must assure emission reductions from the affected sources. Under section 111(d)(1), the states must submit state plans that "establish[] standards of performance for any existing source," and, under section 111(a)(1) and the EPA's implementing regulations, those standards are informed by the EPA's determination of the best system of emission reduction adequately demonstrated. Because the emission standards must apply to the affected sources, actions taken by affected sources that do not result in emission reductions from the affected sources—for example, offsets (*e.g.*, the planting of forests to sequester CO_2)—do not qualify

[574] Commenters offered hypothetical examples to illustrate their concerns over precedential effects, discussed below. Some commenters objected that our proposed interpretation of the BSER failed to include limiting principles. In the Legal Memorandum, we note that the statutory constraints discussed in this section of the preamble constitute limits on the type of the BSER that the EPA is authorized to determine.

for inclusion in the BSER. Building blocks 2 and 3 achieve emission reductions from the affected EGUs, and thus are not precluded under this constraint.

(b) *Controls or measures that affected EGUs can implement.*

The second constraint is that because the affected EGUs must be able to achieve their emission performance rates through the application of the BSER, the BSER must be controls or measures that the EGUs themselves can implement. Moreover, as noted, the D.C. Circuit has established criteria for achievability in the section 111(b) case law; *e.g.*, sources must be able to achieve their standards under a range of circumstances. If those criteria are applicable in a section 111(d) rule, the BSER must be of a type that allows sources to meet those achievability criteria. As noted, under this rule, affected EGUs can achieve their emission performance rates in the various circumstances under which they operate, through the application of the building blocks.

(c) *"Adequately demonstrated."*

The third constraint is that the system of emission reduction that the EPA determines to be the best must be "adequately demonstrated." To qualify as the BSER, controls and measures must align with the nature of the regulated industry and the nature of the pollutant so that implementation of those controls or measures will result in emission reductions from the industry and allow the sources to achieve their emission performance standards. The history of the effectiveness of the controls or other measures, or other indications of their effectiveness, are important in determining whether they are adequately demonstrated.

More specifically, the application of building blocks 2 and 3 to affected EGUs has a number of unique characteristics. Building blocks 2 and 3 entail the production of the same amount of the same product—electricity, a fungible product that can be produced using a variety of highly substitutable generation processes—through the cleaner (that is, less CO_2-intensive) processes of shifting dispatch from steam generators to existing NGCC units, and from both steam generators and NGCC units to renewable generators.

The physical properties of electricity and the highly integrated nature of the electricity system allow the use of these cleaner processes to generate the same amount of electricity. In addition, the electricity sector is primarily domestic—little electricity is exported outside the U.S.—and there is low capacity for storage. In addition, the electricity sector is highly regulated, planned, and coordinated. As a result, holding demand constant, an increase in one type of generation will result in a decrease in another type of generation. Moreover, the higher-emitting generators, which are fossil fuel-fired, have higher variable costs than renewable generators, so that increased renewable generation will generally back out fossil fuel-fired generation.

Because of these characteristics, the electricity sector has a long and well-established history of substituting one type of generation for another. This has occurred for a wide variety of reasons, many of which are directly related to the system's primary purposes and functions, as well as for environmental reasons. As a result, at present, there is a well-established network of business and operational relationships and past practices that supports building blocks 2 and 3. As noted elsewhere, a large segment of steam generators already have business relationships with existing NGCC units, and a large segment of all fossil fuel-fired EGUs already own, co-own, or have invested in RE.

Many of these characteristics are unique to the utility power sector. Moreover, this complex of characteristics, ranging from the physical properties of electricity and the integrated nature of the grid to the institutional mechanisms that assure reliability and the existing practices and business relationships in the industry, combine to facilitate the implementation of building blocks 2 and 3 in a uniquely efficient manner. This supports basing the emission limits on the ability of owners and operators of fossil fuel-fired EGUs to replace their generation with cleaner generation in other locations, sometimes owned by other entities.

As noted above, commenters offered hypothetical examples to illustrate their concerns over precedential effects. Most of their concerns focused on building block 4, and most of their hypothetical examples concerned reductions in demand for various types of products. We address these concerns in the response to comments document, but we note here that, in any event, these concerns are mooted because we are not finalizing building block 4. Some commenters offered hypothetical examples for building blocks 2 and 3 as well. For example, some commenters asserted that the EPA could "develop standards of performance for tailpipe emissions from motor vehicles" by "requiring car owners to shift some of their travel to buses," which the commenters considered analogous to building block 2; or by "requiring there to be more electric vehicle purchases," which the commenters considered analogous to building block 3.[575]

Commenters' concerns over precedential impact cannot be taken to mean that the building blocks should not be considered to meet the requirements of the BSER or that the affected EGUs cannot be considered to meet the emission limits by implementing those measures. Moreover, because many of these individual characteristics, and their inherent complexity, are unique to the utility power sector, building blocks 2 and 3 as applied to fossil fuel-fired EGUs will have a limited precedent for other industries and other types of rulemakings. For example, the commenter's hypothetical examples noted above are inapposite for several reasons. The hypotheticals appear to be premised on government action mandating actions not implementable by emitting sources (*e.g.*, that a government would "require[e] car owners to shift some of their travel to buses, or . . . require[e] there to be more electric vehicle purchases"), whereas the measures in building blocks 2 and 3 can be implemented by the affected EGUs. Nor have commenters attempted to address how car owners shifting travel to buses or purchasing more

[575] UARG comment at 2–3.

electric vehicles could be translated into lower tailpipe standards for motor vehicles.[576]

(d) *"Best" in light of "cost . . . nonair quality health and environmental impact and energy requirements" and EPA's past practice and current policy.*

The fourth constraint, or set of constraints, is that the system of emission reduction must be the "best," "taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements." As noted, in light of the D.C. Circuit case law, the EPA has considered cost and energy factors on both an individual source basis and on the basis of the nationwide electricity sector. In determining what is "best," the EPA has broad discretion to balance the enumerated factors.[577] In interpreting and applying these provisions in this rulemaking to regulate CO_2 emissions from affected EGUs under section 111(d), we are acting consistently with our past practice for applying these provisions in previous section 111 rulemakings and for regulating air pollutants from the electricity sector under other provisions of the CAA, as well as current policy.

The great majority of our regulations under section 111 have been 111(b) regulations for new sources. As discussed in the Legal Memorandum and briefly below, the BSER identified under section 111(b) is designed to assure that affected sources are well controlled at

[576] In any event, it is questionable whether measures such as those hypothesized by the commenters would be consistent with the provisions of Title II.

[577] *See Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

the time of construction, and that approach is consistent with the design expressed in the legislative history for the 1970 CAA Amendments that enacted the provision.

Traditionally, CAA section 111 standards have been rate-based, allowing as much overall production of a particular good as is desired, provided that it is produced through an appropriately clean (or low-emitting) process. CAA section 111 performance standards have primarily targeted the means of production in an industry and not consumers' demand for the product. Thus, the focus for the BSER has been on how to most cleanly produce a good, not on limiting how much of the good can be produced.

One example of the focus under section 111 on clean production, not limitation of product is provided by the revised new source performance standards for electric utility steam generating units that we promulgated in 1979 following the 1977 CAA Amendments to limit emissions of SO_2, PM, and NO_X. In relevant part, the revised standards limited SO_2 emissions to 1.20 lb/million BTU heat input and imposed a 90 percent reduction in potential SO_2 emissions. This was based on the application of flue gas desulfurization (FGD) together with coal preparation techniques. In the preamble, we explain that "[t]he intent of the final standards is to encourage power plant owners and operators to install the best available FGD systems and to implement effective operation and maintenance procedures but not to create power supply disruptions." [578] [579] EPA has taken the same overall approach in its section 111(d) rules,[580] including the CAMR rule noted below.

Similarly, in a series of rulemakings regulating air pollutants from EGUs under several provisions of the CAA, we have focused our efforts on assuring that

[578] *See, e.g.*, 44 FR 33580, at 33599 (June 11, 1979). In this rulemaking, the EPA recognized the ability of the integrated grid to minimize power disruptions: "When electric load is shifted from a new steam-electric generating unit to another electric generating unit, there would be no net change in reserves within the power system. Thus, the emergency condition provisions prevent a failed FGD system from impacting upon the utility company's ability to generate electric power and prevents an impact upon reserves needed by the power system to maintain reliable electric service." *Id.*

[579] The EPA's 1982 revised new source performance standards for certain stationary gas turbines provide another example of a rulemaking that focused controls on reducing emissions, as well as reliance on the integrated grid to avoid power disruptions. 44 FR 33580 (June 11, 1979). In response to comments that requested a NO_X emission limit exemption for base load utility gas turbines, the EPA explained that "for utility turbines . . . since other electric generators on the grid can restore lost capacity caused by turbine down time" the NO_X emission limit of 1150 ppm for such turbines would not be rescinded. 44 FR 33580, at 33597–98.

[580] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 FR 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 FR 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 FR 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 FR 26294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 FR 9905 (Mar. 12, 1996).

electricity is generated through cleaner or lower-emitting processes, and we have not sought to limit the aggregate amount of electricity that is generated. We describe those rules in section II, elsewhere in this section V.B.3., and in the Legal Memorandum.

For example, as discussed in the Legal Memorandum, in the three transport rules promulgated under CAA section 110(a)(2)(D)(i)(I)—the NO_X SIP Call, CAIR, and CSAPR—which regulated precursors to ozone-smog and particulate matter, the EPA based certain aspects of the regulatory requirements on the fact that fossil fuel-fired EGUs could shift generation to lower-emitting sources. In CAMR, the 2005 rulemaking under section 111(d) regulating mercury emissions from coal-fired EGUs, the EPA based the first phase of control requirements on the actions the affected EGUs were required to take under CAIR, including shifting generation to lower-emitting sources. In addition, as also discussed in the Legal Memorandum, in the EPA's 2012 MATS rule regulating mercury from coal-fired EGUs under section 112, at industry's urging, the EPA allowed compliance deadlines to be extended for coal-fired EGUs that desired to substitute replacement power of any type, including NGCC units or RE, for compliance purposes.

While these and other rulemakings for fossil fuel-fired EGUs took different approaches towards lower-emitting generation and renewable generation, they all were based on control measures that reduced emissions without reducing aggregate levels of electricity generation. It should be noted that even though some of those rules established overall emission limits in the form of budgets implemented through a cap-and-trade program, the EPA recognized that the fossil fuel-fired EGUs that were subject to the rules could comply by shifting generation to lower-emitting EGUs, including relying on RE. In this manner, the rules limited emissions but on the basis that the industry could implement lower-emitting processes, and not based on reductions in overall generation.

We are applying the same approach to this rulemaking. Our basis for this rulemaking is that affected EGUs can implement a system of emission reduction that will reduce the amount of their emissions without reducing overall electricity generation. This approach takes into account costs by minimizing economic disruption as well as the nation's energy requirements by avoiding the need for environmental-based reductions in the aggregate amount of electricity available to the consumer, commercial, and industrial sectors.

This approach is a reasonable exercise of the EPA's discretion under section 111, consistent with the U.S. Supreme Court's statements in its 2011 decision, *American Electric Power Co.* v. *Connecticut*, that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil-fuel fired power plants. There, the Court emphasized that CAA section 111 authorizes the EPA—which the Court identified as the "expert agency"—to regulate CO_2 emissions from fossil fuel-fired power plants based an "informed assessment of competing interests . . . . Along with the environmental benefit potentially achievable, our

Nation's energy needs and the possibility of economic disruption must weigh in the balance." [581]

Similarly, the D.C. Circuit, in a 1981 decision upholding the EPA's section 111(b) standards for air pollutants from fossil fuel-fired EGUs, stated that section 111 regulations concerning the electric power sector "demand a careful weighing of cost, environmental, and energy considerations." [582]

This exercise of policy discretion is consistent with Congress's expectation that the Administrator "should determine the achievable limits" [583] and "would establish guidelines as to what the best system for each such category of existing sources is."[584] As the D.C. Circuit explained, "[i]t seems likely that if Congress meant . . . to curtail EPA's discretion to weigh various policy considerations it would have explicitly said so in section 111, as it did in other parts of the statute."[585]

Our interpretation that CAA section 111 targets supply-side activities that allow continued production of a product through use of a cleaner process, rather than targeting consumer-oriented behavior, also

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[581] *American Electric Power Co.* v. *Connecticut*, 131 S. Ct. 2527, 2539–40 (2011).

[582] *Sierra Club* v. *EPA*, 657 F.2d 298, 406 (D.C. Cir. 1981). *Id.* at 406 n. 526.

[583] S. Rep. No. 91-1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16 (explaining that the "[Administrator] should determine the achievable limits and let the owner or operator determine the most economic, acceptable technique to apply.").

[584] H.R. Rep. No. 95-294, at 195 (May 12, 1977).

[585] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

furthers Congress' intent of promoting cleaner production measures "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."[586] This principle is also consistent with promoting "reasonable . . . governmental actions . . . for pollution prevention."[587]

In this rule, we are applying that same approach in interpreting the BSER provisions of section 111. That is, we are basing the regulatory requirements on measures the affected EGUs can implement to assure that electricity is generated with lower emissions, taking into account the integrated nature of the industry and current industry practices. Building blocks 1, 2 and 3 fall squarely within this paradigm; they do not require reductions in the total amount of electricity produced.

We recognize that commenters have raised extensive legal concerns about building block 4. We recognize that building block 4 is different from building blocks 1, 2, and 3 and the pollution control measures that we have considered under CAA section 111. Accordingly, under our interpretation of section 111, informed by our past practice and current policy, today's final action excludes building block 4 from the BSER. Building block 4 is outside our paradigm for section 111 as it targets consumer-oriented behavior and demand for the good, which would reduce the amount of electricity to be produced.

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[586] CAA section 101(b)(1).

[587] CAA section 101(c).

Although numerous commenters urged us to include demand-side EE measures as part of the BSER, as we had proposed to do, we conclude that we cannot do so under our historical practice, current policy, and current approach to interpreting section 111 as well as our historical practice in regulating the electricity sector under other CAA provisions. While building blocks 2 and 3 are rooted in our past practice and policy, building block 4 is not and would require a change (which we are not making) in our interpretation and implementation and application of CAA section 111.

Excluding demand-side EE measures from the BSER has the benefit of allaying legal and other concerns raised by commenters, including concerns that individuals could be "swept into" the regulatory process by imposing requirements on "every household in the land." [588] While building block 4 could have been implemented without imposing requirements on individual households, this final rule resolves any doubt on this matter and is not based on the inclusion of demand-side EE as part of the BSER.

By the same token, we are not finalizing reduced generation of electricity overall as the BSER. Instead, components of the BSER focus on shifting generation to lower- or zero-emitting processes for producing electricity.[589]

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[588] *See Util. Air Reg. Group* v. *EPA*, 134 S. Ct. 2427, 2436 (2014).

[589] As discussed below, however, reduced generation remains important to this rule in that it is one of the methods for implementing the building blocks.

(e) *Constraints for new sources.*

For new sources, practical and policy concerns support the interpretation of basing the BSER on controls that new sources can install at the time of construction, so that they will be well-controlled throughout their long useful lives. This approach is consistent with the legislative history. We discuss this at greater length in the Legal Memorandum.

4. Relationship Between a Source's Implementation of Building Blocks 2 and 3 and Its Emissions

In this section, we discuss the relationship between an affected EGU's implementation of the measures in building blocks 2 and 3 and that affected EGU's own generation and emissions. As discussed above, an affected EGU subject to a CAA section 111(d) state plan that imposes an emission rate-based standard may achieve that standard in part by implementing the measures in building block 2 (for a steam generator) and building block 3 (for a steam generator or combustion turbine). That is, an affected EGU may invest in low- or zero-emitting generation and may apply credits from that generation against its emission rate. Those credits reduce the affected EGU's emission rate and thereby help it to achieve its emission limit.

In addition, the additional low- or zero-emitting generation that results from the affected EGU's investment will generally displace higher-emitting generation. This is because, as described above, higher-emitting generation generally has higher variable costs, reflecting its fuel costs, than, at least, zero-emitting generation. Displacement of higher-emitting generation will lower overall CO_2 emissions from the source category of affected EGUs.

If an affected EGU implements building block 2 or 3 by reducing its own generation, it will reduce its own emissions. However, the affected EGU may also or alternatively choose to implement building block 2 or 3 by investing in lower- or zero-emitting generation that does not, in and of itself, reduce the amount of its own generation or emissions. Even so, implementation of building blocks 2 and 3 will reduce CO_2 from some affected EGUs, and therefore reduce CO_2 on a source category-wide basis.

This outcome is, however, consistent with the requirements of CAA section 111(d)(1) and (a)(1). To reiterate, CAA section 111(d)(1) requires that "any existing source" have a "standard of performance," defined under CAA section 111(a)(1) as "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 . . . adequately demonstrated [BSER] . . . ." These provisions require by their terms that "any existing source" must have a "standard of performance," but nothing in these provisions requires a particular amount—or, for that matter, any amount—of emission reductions from each and every existing source. That the "standard of performance" is defined on the basis of the "degree of emission limitation achievable through the application of the [BSER]" does not mean that each affected EGU must achieve some amount of emission reduction, for the following reasons.

The cornerstone of the definition of the term "standard of performance" is the BSER. In determining the BSER, the EPA must consider the amount of emission reduction that the system may achieve, and must consider the ability of the affected EGUs to achieve the emission limits that result from the application of the BSER. The EPA is authorized to include in the BSER, for this source category, the measures in building blocks 2 and 3 because, when applied to the source category, these measures result in emission standards that may be structured to ensure overall emission reductions from the source category and remain achievable by the affected EGUs. This remains so regardless of whether the "degree of emission limitation achievable through the application of the [BSER]" by any particular source results in actual emission reductions from that source.

The application of the building blocks has an impact that is similar to that of an emissions trading program, under which, overall, the affected sources reduce emissions, but any particular source does not need to reduce its emissions and, in fact, may increase its emissions, as long as it purchases sufficient credits or allowances from other sources. In fact, we expect that many states will carry out their obligations under this rule by imposing standards of performance that incorporate trading or other multi-entity generation-replacement strategies. Indeed, any emission rate-based standard may not necessarily result in emission reductions from any particular affected source (or even all of the affected sources in the category) as a result of the ability of the particular source (or even all of them) to increase its production and, therefore, its emissions, even while maintaining the required emission rate.

5. Reduced Generation and Implementation of the BSER

In the proposed rulemaking, we described the BSER as the measures included in building block 1 as well the set of measures included in building blocks 2, 3 and 4 or, in the alternative, reduced generation or utilization by the affected EGUs in the amount of building blocks 2, 3 and 4. In this final rule, based on the comments and further evaluation, we are refining our approach to the BSER. Specifically, we are determining the BSER as the combination of measures included in building blocks 1, 2, and 3. Building blocks 2 and 3 entail substitution of lower-emitting generation for higher-emitting generation, which ensures that aggregate production levels can continue to meet demand even where an individual affected EGU decreases its own output to reduce emissions. The amount of generation from the increased utilization of existing NGCC units determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs could undertake to achieve building block 2, and the amount of generation from the use of expanded lower- or zero-emitting generating capacity that could be provided, determines a portion of the amount of reduced generation that affected fossil fuel-fired steam EGUs, as well as the entire amount of reduced generation that affected NGCC units could undertake to implement building blocks 2 and 3. This section discusses the reasons that reduced generation is one of the set of reasonable and well-established actions that an affected EGU can implement to achieve its emission limits. We are not finalizing our proposal that reduced overall generation of electricity may by itself be considered the BSER, for the reason that reduced generation by itself does not fit within our historical and current interpretation of the BSER. Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions.

a. *Background.* As noted, for both rate-based and mass-based state plans, affected EGUs may take a set of actions to comply with their emission standards. An affected EGU may comply with an emission rate-based standard (*e.g.*, a limit on the amount of CO_2 per MWh) by acquiring, through one means or another, credits from lower- or zero-emitting generation (building blocks 2 or 3) to reduce its emission rate for compliance purposes. In addition, the affected EGU may reduce its generation, and if it does so, it then needs to acquire fewer of those credits to meet its emission rate.[590] Under these circumstances, the affected EGU would in effect replace part of its higher-emitting generation with lower- or zero-emitting generation. On the other hand, an affected EGU that is subject to a mass-based standard—for example, a requirement to hold enough allowances to cover its emissions (*e.g.*, one allowance for each ton of emissions in any year)—may comply at least in part by reducing its generation and, thus, its emissions. Therefore, one type of action that an affected EGU may take to achieve either of these

[590] An affected EGU that is subject to an emission rate, *e.g.*, pounds of CO_2 per MWh generated, cannot achieve that rate simply by reducing its generation (unless it shuts down, in which case it would achieve a zero emission rate). This is because although reducing generation results in fewer emissions, it does not, by itself, result in fewer emissions per MWh generated.

emission limits is to reduce its generation. Further, reduced generation by individual sources offers a pathway to compliance in and of itself. That is, a state may adopt a mass-based goal, assign mass-based standards to its sources, and those sources may comply with their mass-based limits by, in addition to implementing building block 1 measures, reducing their generation in the appropriate amounts, and without taking any other actions.

b. *Well-established use of reduced generation to comply with environmental requirements.* Reduced generation is a well-established method for individual fossil fuel-fired power plants to comply with their emission limits.

Reduced generation in the amounts contemplated in this rule, as undertaken by individual sources to achieve their emission limits, reduces emissions from the affected sources, but because of the integrated and interconnected nature of the power sector, can be accommodated without significant cost or disruption. The electric transmission grid interconnects the nation's generation resources over large regions. Electric system operators coordinate, control, and monitor the electric transmission grid to ensure cost-effective and reliable delivery of power. These system operators continuously balance electricity supply and demand, ensuring that needed generation and/or demand resources are available to meet electricity demand. Diverse resources generate electricity that is transmitted and distributed through a complex system of interconnected components to end-use consumers.

The electricity system was designed to meet these core functions. The three components of the electricity supply system—generation, transmission and distribution—coordinate to deliver electricity from the point of generation to the point of consumption. This interconnectedness is a fundamental aspect of the nation's electricity system, requiring a complicated integration of all components of the system to balance supply and demand and a federal, state and local regulatory network to oversee the physically interconnected network. Electricity from a diverse set of generation resources such as natural gas, nuclear, coal and renewables is distributed over high-voltage transmission lines. The system is planned and operated to ensure that there are adequate resources to meet electricity demand plus additional available capacity over and above the capacity needed to meet normal peak demand levels. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units of various types as well as demand-side resources. Importantly, if generation is reduced from one generator, safeguards are in place to ensure that adequate supply is still available to meet demand. We describe these safeguards in the background section of this preamble.

Both Congress and the EPA have recognized reduced generation as one of the measures that fossil fuel-fired EGUs may implement to reduce their emissions of air pollutants and thereby achieve emission limits. Congress, in enacting the allowance requirements in CAA Title IV, under which fossil fuel-fired EGUs must hold an allowance for each ton of SO_2 emitted, explicitly recognized that fossil fuel-fired EGUs could meet this requirement by reducing their generation. In fact, Congress anticipated that fossil fuel-fired EGUs may choose to comply with the SO_2 emission limits by reducing utilization, and included provisions that specifically addressed reduced utilization. For example, CAA section 408(c)(1)(B) includes requirements for an owner or operator of an EGU that meets the Phase 1 SO_2 reduction obligations and the NO_X reduction obligations "by reducing utilization of the unit as compared with its baseline or by shutting down the unit."

The EPA has also recognized in several rulemakings limiting emissions from fossil fuel-fired EGUs that reduced generation is one of the methods of emission reduction that an EGU was expected to rely on to achieve its emission limitations. Examples include rulemakings to impose requirements that sources implement BART to reduce their emissions of air pollutants that cause or contribute to visibility impairment. As explained earlier, for certain older stationary sources that cause or contribute to visibility impairment, including fossil fuel-fired EGUs, states must determine BART on the basis of five statutory factors, such as costs and energy and non-air quality impacts. [591] In 1980, the EPA promulgated a regulatory definition of BART: "an emission limitation based on the degree of reduction achievable through the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." [592] Both the statutory factors and the regulatory definition resemble the definition of the BSER under CAA section 111(a)(1) (although, as noted, the statutory definition of BART

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[591] CAA section 169A(g)(2).

[592] 40 CFR 51.301.

is more technology focused than the definition of BSER). In its regional haze SIP, the State of New York determined that BART for the NO_X emissions from two coal-fired boilers that served as peaking units was caps on baseline emissions rates and annual capacity factors of 5 percent and 10 percent, respectively.[593]

There have been numerous other instances in which fossil fuel-fired EGUs have reduced their individual generation, or placed limits on their generation, in order to achieve, or obviate, emission standards. In fact, there are numerous examples of EGUs that take restrictions on hours of operation in their permits for the purpose of avoiding CAA obligations, including avoiding triggering the requirements of the Prevention of Significant Deterioration (PSD), Nonattainment New Source Review (NNSR), or Title V programs (including Title V fees), and avoiding triggering HAP requirements. Such restrictions may also be taken to limit emissions of pollutants, such as limiting emissions of criteria pollutants for attainment purposes.

More specifically, EPA's regulations for a number of air programs expressly recognize that certain sources may take enforceable limits on hours of operation in order to avoid triggering CAA obligations that would otherwise apply to the source. Stationary sources that emit or have the *potential to emit* a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements.[594] A source may

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[593] 77 FR 24794, 24810 (Apr. 25, 2012).

[594] *See, e.g.*, CAA sections 112(a)(1), 112(d)(1), 165(a), 169(1), 172(c)(5), 173(a) & (c), 501(2), 502(a), 302(j).

voluntarily obtain a synthetic minor limitation—that is, a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level—to avoid triggering a major stationary source requirement.[595] Such synthetic minor limits may be based on restrictions on the hours of operation, as provided in EPA's regulations defining "potential to emit," as well as on air pollution control equipment. "Potential to emit" is defined, for instance, in the regulations for the PSD program for permits issued under federal authority as: "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and *restrictions on hours of operation* . . . shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable,"[596] or "legally and practicably enforceable by a state or local air pollution control agency."[597] The

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[595] *See*, *e.g.*, Memorandum from Terrell Hunt, Assoc. Enforcement Counsel, U.S. EPA, & John Seitz, Director, Stationary Source Compliance Div., U.S. EPA, Guidance on Limiting Potential to Emit in New Source Permitting, at 1–2, 6 (June 13, 1989), available at *http://www.epa.gov/region07/air/nsr/nsrmemos/lmitpotl.pdf* ("Restrictions on production or operation that will limit potential to emit include limitations on quantities of raw materials consumed, fuel combusted, *hours of operation*, or conditions which specify that the source must install and maintain controls that reduce emissions to a specified emission rate or to a specified efficiency level.") (emphasis added).

[596] 40 CFR 52.21(b)(4) (emphasis added).

[597] John Seitz, Director, Office of Air Quality Planning and Standards, and Robert Van Heuvelen, Director, Office of Regulatory Enforcement, *Release of Interim Policy on Federal*

regulations for other air programs similarly recognize that potential to emit may be limited through restrictions on hours of operations in their corresponding definitions of "potential to emit." [598] These regulatory provisions make clear that restrictions on potential to emit include both "air pollution control equipment" and "restrictions on hours of operation," and indicate that these are equally cognizable means of restricting emissions to comply with, or avoid, CAA requirements.[599]

As one of many examples of a fossil-fuel fired EGU taking restrictions on hours of operation for the purpose of avoiding CAA obligations, Manitowoc Public Utilities in Wisconsin obtained a Title V renewal permit that limited the operating hours of the single simple-cycle combustion turbine to not more than 194 hours per month, averaged over any consecutive 12 month period, as part of limiting its potential to emit for volatile organic compounds below the Title V threshold of 100 tpy, and carbon monoxide, NO_X and SO_2 below the PSD threshold of 250 tpy.[600]

Enforceability of Limitations on Potential to Emit, at 3 (Jan. 22, 1996), available at *http://www.epa.gov/region07/air/nsr/nsrmemos/pottoemi.pdf*.

[598] *See* 40 CFR 51.166(b)(4) (addressing SIP approved PSD programs), 51.165(a)(1)(iii) (addressing SIP approved NNSR programs), 70.2 (addressing Title V operating permit programs), and 63.2 (addressing hazardous air pollutants).

[599] *See*, *e.g.*, 40 CFR 52.21(b)(4).

[600] *See* Final Operation Permit No. 436123380-P10 for Manitowoc Public Utilities—Custer Street (Wis. Dept. Nat. Res., 8/19/2013), Condition ZZZ.1.a(1) at p. 9 (Limiting potential to emit) and n. 11 ("These conditions are established so that the potential emissions for volatile organic compounds will not

As another example, Sunbury Generation LP in Pennsylvania obtained a minor new source preconstruction permit, called a plan approval, for a repowering project from the Pennsylvania Department of Environmental Protection in 2013 that limited the hours of operation of three combined cycle combustion turbines that were planned for construction in order to remain below the significance threshold for GHGs.[601] The Legal Memorandum includes numerous other examples of power plants

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exceed 99 tons per year and potential emissions for carbon monoxide, nitrogen oxides and sulfur dioxide emissions from the facility will not exceed 249 tons per year."). *See also* Analysis and Preliminary Determination for the Renewal of Operation Permit 436123380-P01 (Wis. Dept. Nat. Res., 5/21/2013) at p. 5 (noting that the "existing facility is a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The existing facility is a minor source under PSD and an area source of federal HAP" and further noting that after renewal, "the facility will continue to be a major source under Part 70 because potential emissions of sulfur dioxide, nitrogen oxides and carbon monoxide exceed 100 tons per year. The facility will also continue to be a minor source under PSD and an area source of federal HAP.").

[601] *See* Plan Approval No. 55-00001E for Sunbury Generation LP (Pa. Dept. Env. Protection, 4/1/2013), Conditions #016 on pp. 24, 32 and 40 (limiting turbine units to operating no more than 7955, 6920, or 8275 hours in any 12 consecutive month period depending on which of three turbine options was selected); Memorandum from J. Piktel to M. Zaman, *Addendum to Application Review Memo for the Repowering Project* (Pa. Dept. Env. Protection, 4/1/2013) at p. 2 of 10 (noting that source had "calculated a maximum hours per year (12 consecutive month period) of operation for the sources proposed for each of the turbine options in order to remain below the significance threshold for GHGs.").

accepting permit limits that reduce generation to meet, or avoid the need to meet, emission limits.

There are several ways that an affected EGU may implement reduced generation. For example, an EGU may accept a permit requirement that specifically limits its operating hours. In addition, an EGU may treat the cost of its generation as including an additional amount associated with environmental impacts, which requires it to raise its bid price, so that the EGU is dispatched less.

c. *Other aspects of reduced generation.*

The amounts of increased existing NGCC generation and new renewables, in the amounts reflected in building blocks 2 and 3, can be substituted for generation at affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building block 3 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may choose to reduce their CO_2 emissions by means of reducing their generation.

Reduced generation by affected EGUs, in the amounts that affected EGUs may rely on to implement the selected building blocks, will not have adverse effects on the utility power sector and will not reduce overall electricity generation. In light of the emission limits of this rule, because of the availability of the measures in building blocks 2 and 3, and because the grid is interconnected and the electricity system is highly planned, reductions in generation by fossil fuel-fired EGUs in the amount contemplated if they were to implement the building blocks, and occurring over the lengthy time frames provided under this rule, will result in replacement generation that generally is lower- or zero-emitting. Mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. As a result, reduced generation will not give rise to reliability concerns or have other adverse effects on the utility power sector and are of reasonable cost for the affected source category and the nationwide electricity system.[602] All these results come about because the operation of the electrical grid through integrated generation, transmission, and distribution networks creates substitutability for electricity and electricity services, which allows decreases in generation at affected fossil fuel-fired

[602] Although, as discussed in the text in this section of the preamble, we are not treating reduced overall generation of electricity as the BSER (because it does not meet our historical and current approach of defining the BSER to include methods that allow the same amount of production but with a lower-emitting process) we note that reduced generation by individual higher-emitting EGUs to implement building blocks 2 and 3 meets the following criteria for the BSER: As the examples in the text and in the Legal Memorandum make clear, reduced generation is "adequately demonstrated" as a method of reducing emissions (because Congress and the EPA have recognized it and on numerous occasions, power plants have relied on it); it is of reasonable cost; it does not have adverse effects on energy requirements at the level of the individual affected source (because it does not require additional energy usage by the source) or the source category or the U.S.; and it does not create adverse environmental problems.

steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2) and allows decreases in generation at all affected EGUs to be replaced by increased generation at new lower- and zero-emitting EGUs (building block 3). Further, this substitutability increases over longer timeframes with the opportunity to invest in infrastructure improvements, and as noted elsewhere, this rule provides an extended state plan and source compliance horizon.

d. *Comments concerning limiting principles.*

A commenter stated that "an interpretation of ['system of emission reduction'] that relies primarily on reduced utilization has no clear limiting principle."[603] We disagree with this concern, for the following reasons.

As discussed, in this final rule, we are identifying the BSER as the combination of the three building blocks. Building blocks 2 and 3 entail substitution of lower- or zero-emitting generation for higher-emitting generation, and one component of that substitution is reduced generation, which is limited in several respects discussed below. Accordingly, our identification of the BSER in this final rule does not "rel[y] primarily" on reduced utilization in and of itself (and therefore reduced generation of the product overall, electricity) as the BSER. Rather, the BSER is, in addition to building block 1, the substitution of lower- or zero-emitting generation for higher emitting generation, and reduced utilization may be a way to implement that substitution and is one of numerous

[603] EEI comment, at 284.

methods that affected EGUs may employ to achieve or help achieve the emission limits established by these emission guidelines.[604] The commenter's concerns over a perceived lack of a limiting principle cannot be taken to mean that reduced generation by higher-emitting EGUs cannot be considered to be a method for affected EGUs to achieve their emission limits.

Moreover, reduced generation, as applied to affected EGUs in this rule, is limited in a number of respects.

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[604] Indeed, load shifting—as substitute generation is sometimes called—is an "easy and fairly inexpensive strategy" that "may be used in conjunction with other control measures" for "emission reduction." Donald S. Shepard, "A Load Shifting Model for Air Pollution Control in the Electric Power Industry," Journal of the Air Pollution Control Association, Vol. 20, No. 11, p. 760 (Nov. 1970). In fact, load shifting has been recognized as a pollution control technique as early as 1968, when it was included in the "Chicago Air Pollution System Model" for controlling incidents of extremely high pollution. E.J. Croke, et al., "Chicago Air Pollution System Model, Third Quarterly Progress Report," Chicago Department of Air Pollution Control, p. 186 (1968) (discussing the feasibility of "Control by Load Reduction" in combination with load shifting as applied to the Commonwealth Edison Company), *available at http://www.osti.gov/scitech/servlets/purl/4827809*. The report also considered "combining fuel switching and load reduction" as a possible air pollution abatement technique. *See id.* at 188. The report recognized, as an initial matter, that the Commonwealth Edison Company (CECO) was "constrained to meet the total load demand" but that "load reduction at one plant or even a number of plants is usually feasible by shifting the power demand to other plants in the system." *Id.* As a result, the report noted, "load shifting within the physical limits of the CECO system . . . may be a highly desirable control mechanism." *Id.* The report also predicted that "[i]n the future, it may be possible to form reciprocal agreements to obtain 'pollution abatement' power from neighbor companies during a pollution incident and return this borrowed power at some later date." *Id.* at 187.

The amount of reduced generation is the amount of replacement generation that is lower- or zero-emitting, that is of reasonable cost, that can be generated without jeopardizing reliability, and that meets the other requirements for the BSER. As discussed, that amount is the amount of generation in building blocks 2 and 3.[605]

Finally, as discussed, the integrated nature of the electricity system, coupled with the high substitutability of electricity, allows EGUs to reduce their generation without adversely affecting the availability of their product. Those characteristics facilitate replacement of generation that has been reduced, and for that reason, EGUs have a long history of reducing their generation and either replacing it directly or having it replaced through the operation of the interconnected electricity system through measures similar to those in building blocks 2 and 3. Thus, an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid, combined with the high degree of planning and various reliability safeguards, will result in entities providing replacement generation. This means that consumers receive exactly the same amount of the same product, electricity, after the reduced generation that they received before it. No other industry is both physically

[605] The EPA notes that affected EGUs are not actually required to collectively reduce generation by the amount represented in the BSER, and may collectively reduce generation by more or less than that amount. Individual affected EGUs are free to choose reduced generation or other means of reducing emissions, as permitted by their state plans, in order to achieve the standards of performance established for them by their states.

interconnected in this manner and manufactures such a highly substitutable product; as a result, the use of reduced generation is not easily transferrable to another industry.

6. Reasons That This Rule Is Within the EPA's Statutory Authority and Does Not Represent Over-Reaching

In this section, we respond to adverse comments that the EPA is overreaching in this rulemaking by attempting to direct the energy sector. These commenters construed the proposed rulemaking as the EPA proposing to mandate the implementation of the measures in the building blocks, including investment in RE and implementation of a broad range of state and utility demand-side EE programs. Commenters added that in some instances, the affected EGUs and states would have no choice but to take the actions in the building blocks because they would not otherwise be able to achieve their emission standards. Commenters also emphasized that with the proposed portfolio approach, the rule would impose federally enforceable requirements on a wide range of entities that do not emit CO_2 and have not previously been subject to CAA regulation. Commenters cite the U.S. Supreme Court's statements in *Utility Air Regulatory Group* v. *EPA (UARG)*[606] that caution an agency against interpreting its statutory authority in a way that "would bring about an enormous and transformative expansion in [its] regulatory authority without clear congressional authorization," and that add, "When an agency claims to discover in a long-extant statute an unheralded power to regulate

[606] 134 S. Ct. 2427 (2014).

'significant portion of the American economy,' . . . we typically greet its announcement with a measure of skepticism."[607] Commenters assert that in this rule, the EPA is taking the actions that the *UARG* opinion cautioned against. For the reasons discussed below, these comments are incorrect and misunderstand fundamental aspects of this rule. In addition, to the extent these comments address either building block 4 or the portfolio approach they are moot, because the EPA is not finalizing those elements of the proposal.

In this rule, the EPA is following the same approach that it uses in any rulemaking under CAA section 111(d), which is designed to regulate the air pollutants from the source category at issue. First, the EPA identifies the BSER to reduce harmful air pollution. Second, based on the BSER, the EPA promulgates emission guidelines, which generally take the form of emission rates applicable to the affected sources. In this case, the EPA is promulgating a uniform CO_2 emission performance rate for steam-generating EGUs and a uniform CO_2 emission performance rate for combustion turbines, and the EPA is translating those rates into a combined emission rate and equivalent mass limit for each state. These emission guidelines serve as the guideposts for state plan requirements. The states, in turn, promulgate standards of performance and, in doing so, retain significant flexibility either to promulgate rate-based emission standards that mirror the emission performance rates in the guidelines, promulgate rate-based emission standards that are equivalent to the

[607] *Utility Air Regulatory Group* v. *EPA*, 134 S. Ct. 2427, 2444 (2014) (citations omitted).

emission performance rates in the guidelines, or promulgate equivalent mass-based emission standards. The sources, in turn, are required to comply with their emission standards, and may do so through any means they choose. Alternatively, the state may adopt the state-measures approach, which provides additional flexibility.

Thus, the EPA is not requiring that the affected EGUs take any particular action, such as implementation of the building blocks. Rather, as just explained, the EPA is regulating the affected EGUs' emissions by requiring that the state submit state plans that achieve specified emission performance levels. The states may choose from a wide range of emission limits to impose on their sources, and the sources may choose from a wide range of compliance options to achieve their emission limits. Those options include various means of implementing the building blocks as well as numerous other compliance options, ranging from—depending in part on whether the state imposes a rate-based or mass-based emission limit—implementation of demand-side EE measures to natural gas co-firing.[608]

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[608] In fact, the EPA is expressly precluded from mandating specific controls except in certain limited circumstances. *See* 42 U.S.C. 7411(b)(5). For instance, the EPA is authorized to mandate a particular "design, equipment, work practice, or operational standard, or combination thereof," when it is "not feasible to prescribe or enforce a standard of performance" for new sources. 42 U.S.C. 7411(h)(1). CAA section 111(h) also highlights for us that while "design, equipment, work practice, or operational standards" may be directly mandated by the EPA, CAA section 111(a)(1) encompasses a broader suite of measures for consideration as the BSER.

As some indication of the diverse set of actions we expect to comply with the requirements of this rule, we note that demand-side EE programs, in particular, are expected to be a significant compliance method, in light of their low costs. In addition, the National Association of Clean Air Agencies (NACAA) has issued a report that provides a detailed discussion of 25 approaches to CO_2 reduction in the electricity sector.[609] In addition, we note that the nine RGGI states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont—have indicated that they intend to maintain their current state programs, which this rule would allow, and there are reports that other states may seek to join RGGI.[610] Similarly, California has indicated that it intends to maintain its current state program, which this rule would allow. Other states could employ the types of methods used in Oregon, Washington, Colorado, or Minnesota, described in the background section of this preamble.

As a practical matter, we expect that for some affected EGUs, implementation of the building blocks will be the most attractive option for compliance. This does not mean, contrary to the adverse comments noted above, that this rule constitutes a redesign of the

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[609] NACAA, "Implementing EPA's Clean Power Plan: A Menu of Options (May 2015), *http://www.4cleanair.org/NACAA_Menu_of_Options*. NACAA describes itself as "the national, non-partisan, non-profit association of air pollution control agencies in 41 states, the District of Columbia, four territories and 116 metropolitan areas." *Id.*

[610] Martinson, Erica, "Cap and trade lives on through the states," Politico (May 27, 2014), *http://www.politico.com/story/2014/05/cap-and-trade-states-107135.html.*

energy sector. As discussed above, the building blocks meet the criteria to be part of the best system of emission reduction . . . adequately demonstrated. The fact that some sources will implement the building blocks and that this may result in changes in the electricity sector does not mean that the building blocks cannot be considered the BSER under CAA section 111(d).

In this rule, as with all CAA section 111(d) rules, the EPA is not directly regulating any entities. Moreover, the EPA is not finalizing the proposed portfolio approach. Accordingly, the EPA is neither requiring nor authorizing the states to regulate non-affected EGUs in their CAA section 111(d) plans.[611]

Moreover, contrary to adverse comments, this rule does not require the states to adopt a particular type of energy policy or implement particulate types of energy measures. Under this rule, a state may comply with its obligations by adopting the emission standards approach to its state plan and imposing rate-based or mass-based emission standards on its affected EGUs. In this manner, this rule is consistent with prior section 111(d) rulemaking actions, in which the states have complied by promulgating one or both of those types of standards of performance. In this rulemaking, as an alternative, the state may adopt the state measures approach, under which the state could, if it wishes, adopt particular types of energy measures that would lead to reductions in emissions from its EGUs. But again, this rule does not require the state

[611] A state may regulate non-EGUs as part of a state measures approach, but those measures would not be federally enforceable.

to implement a particular type of energy policy or adopt particular types of energy measures.

It is certainly reasonable to expect that compliance with these air pollution controls will have costs, and those costs will affect the electricity sector by discouraging generation of fossil fuel-fired electricity and encouraging less costly alternative means of generating electricity or reducing demand. But for affected EGUs, air pollution controls necessarily entail costs that affect the electricity sector and, in fact, the entire nation, regardless of what BSER the EPA identifies as the basis for the controls. For example, had some type of add-on control such as CCS been identified as the BSER for coal-fired EGUs, sources that complied by installing that control would incur higher costs. As a result, generation from coal-fired EGUs would be expected to decrease and be replaced at least in part by generation from existing NGCC units and new renewables because those forms of generation would see their competitive positions improved.

This basic fact that EPA regulation of air pollutants from affected EGUs invariably affects the utility sector is well-recognized and in no way indicates that such regulation exceed the EPA's authority. In revising CAA section 111 in the 1977 CAA Amendments, Congress explicitly acknowledged that the EPA's rules under CAA section 111 for EGUs would significantly impact the energy sector.[612] The

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[612] The D.C. Circuit acknowledged this legislative history in *Sierra Club* v. *EPA*, 657 F.2d 298, 331 (D.C. Cir. 1981). There, the Court stated:

Courts have recognized that, too. The U.S. Supreme Court, in its 2011 decision that the CAA and the EPA actions it authorizes displace any federal common law right to seek abatement of CO_2 emissions from fossil fuel-fired power plants, emphasized that CAA section 111 authorizes the EPA—which the Court identified as the "expert agency"—to regulate CO_2 emissions from these sources in a manner that balances "our Nation's energy needs and the possibility of economic disruption:"

> The appropriate amount of regulation in any particular greenhouse gas-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 achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance.
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> The [CAA] entrusts such complex balancing to EPA in the first instance, in combination with state regulators. Each "standard of performance" EPA sets must "tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements." § 7411(a)(1), (b)(1)(B), (d)(1); see also 40 CFR 60.24(f) (EPA may permit

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[T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111. [Citing S. Rep. No. 95-127, 95th Cong., 1st Sess. (1977), 3 Legis. Hist. 1371; H.R. Rep. No. 95-294, 95th Cong., 1st Sess. 188 (1977), 4 Legis. Hist. 2465.]

> state plans to deviate from generally applicable emissions standards upon demonstration that costs are "[u]n-reasonable"). EPA may "distinguish among classes, types, and sizes" of stationary sources in apportioning responsibility for emissions reductions. § 7411(b)(2), (d); see also 40 CFR 60.22(b)(5). And the agency may waive compliance with emission limits to permit a facility to test drive an "innovative technological system" that has "not [yet] been adequately demonstrated." § 7411(j)(1)(A). The Act envisions extensive cooperation between federal and state authorities, see § 7401(a), (b), generally permitting each state to take the first cut at determining how best to achieve EPA emissions standards within its domain, see § 7411(c)(1), (d)(1)–(2).
>
> It is altogether fitting that Congress designated an expert agency, here, EPA, as best suited to serve as primary regulator of greenhouse gas emissions. The expert agency is surely better equipped to do the job than individual district judges issuing ad hoc, case-by-case injunctions.[613]

Similarly, the D.C. Circuit, in its 1981 decision upholding the EPA's rules to reduce SO_2 emissions from new coal-fired EGUs under the version of CAA section 111(b) adopted in the 1977 CAA Amendments, stated:

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[613] *American Electric Power Co.* v. *Connecticut*, 131 S. Ct. 2527, 2539–40 (2011).

> [S]ection 111 most reasonably seems to require that EPA identify the emission levels that are "achievable" with "adequately demonstrated technology." After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations. It follows that to exercise this discretion EPA must examine the effects of technology on the grand scale in order to decide which level of control is best. . . . The standard is, after all, a national standard with long-term effects.[614]

The D.C. Circuit added: "Regulations such as those involved here demand a careful weighing of cost, environmental, and energy considerations. They also have broad implications for national economic policy."[615] This rule has "economic, environmental,

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[614] *Sierra Club* v. *EPA*, 657 F.2d 298, 330 (D.C. Cir. 1981).

[615] *Sierra Club* v. *EPA*, 657 F.2d 298, 406 (D.C. Cir. 1981). The Court supported this statement with a lengthy quotation from a scholarly article, which stated, in part:

> Consider for a moment the chain of collective decisions and their effects just in the case of electric utilities. Petroleum imports can be conserved by switching from oil-fired to coal-fired generation. But barring other measures, burning high-sulfur Eastern coal substantially increases pollution. Sulfur can be "scrubbed" from coal smoke in the stack, but at a heavy cost, with devices that turn out huge volumes of sulfur wastes that must be disposed of and about whose reliability there is some question. Intermittent control techniques (installing high smokestacks and switching off burners when meteorological conditions are adverse) can, at lower cost, reduce local concentrations of sulfur oxides in the air, but cannot cope with the growing

and energy" impacts, as Congress and the Courts expect in a CAA section 111 rule, but those impacts do not mean that the EPA is precluded from promulgating the rule.

As noted above, in this rule, to control CO_2 emissions from affected EGUs, the EPA first considered more traditional air pollution control measures, including supply-side efficiency improvements, fuel-switching (for CO_2 emissions, that entails co-firing with natural gas), and add-on controls (for CO_2 emissions, that entails CCS). However, it became apparent that even if the EPA could have finalized those controls as the BSER [616] and established the same uniform CO_2 emission performance rates, the affected EGUs would rely on less expensive ways to achieve their emission limits.

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problem of sulfates and widespread acid rainfall. Use of low-sulfur Western coal would avoid many of these problems, but this coal is obtained by strip mining. Strip-mining reclamation is possible, but substantially hindered in large areas of the West by lack of rainfall. Moreover, in some coal-rich areas the coal beds form the underground aquifer and their removal could wreck adjacent farming or ranching economies. Large coal-burning plants might be located in remote areas far from highly populated urban centers in order to minimize the human effects of pollution. But such areas are among the few left that are unspoiled by pollution and both environmentalists and the residents (relatively few in number compared with those in metropolitan localities but large among the voting population in the particular states) strongly object to this policy. *Id*. at 406 n. 526.

[616] For the reasons explained, we did not finalize those measures because significantly less expensive control measures—building blocks 2 and 3—are available for these affected EGUs.

Specifically, instead of relying on co-firing and CCS, the affected EGUs generally would replace their generation with lower- or zero-emitting generation—the measures in building blocks 2 and 3—because those measures are significantly less expensive and already well-established as pollution control measures. Indeed, some affected EGUs have stated that while they oppose including in the BSER generation shifts to lower- or zero-emitting sources (or, as proposed, demand-side EE), they request that those measures be available for compliance, which indicates their interest in implementing those measures.[617]

We expect that many sources will choose to comply with their emission limits through the measures in building blocks 2 and 3, but contrary to the assertions of some commenters, this will not result in unprecedented and fundamental alterations to the energy sector. As discussed above, Congress relied on the same measures as those the EPA is including in building blocks 2 and 3 as essential parts of the basis for the Title IV emission limits for fossil fuel-fired EGUs, and the EPA did the same for the emission limits in various rules for those same sources.

In addition, reliance on the measures in building blocks 2 and 3 is fully consistent with the recent changes and current trends in electricity generation, and as a result, would by no means entail fundamental

[617] See the proposal for this rule, 79 FR at 34888 ("during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures, and demand-side energy efficiency measures in order to meet states' and sources' emission reduction obligations.").

redirection of the energy sector. As indicated in the RIA for this rule, we expect that the main impact of this rule on the nation's mix of generation will be to reduce coal-fired generation, but in an amount and by a rate that is consistent with recent historical declines in coal-fired generation. Specifically, from approximately 2005 to 2014, coal-fired generation declined at a rate that was greater than the rate of reduced coal-fired generation that we expect to result from this rulemaking from 2015 to 2030. In addition, under this rule, the trends for all other types of generation, including natural gas-fired generation, nuclear generation, and renewable generation, will remain generally consistent with what their trends would be in the absence of this rule. In addition, this rule is expected to result in increases in demand-side EE.

In addition, contrary to claims of some commenters, in this rule, the EPA is not attempting to expand its authorities by attempting to expand the jurisdiction of the CAA to previously unregulated sectors of the economy, in contravention of the *UARG* decision. In *UARG*, the U.S. Supreme Court struck down the EPA's interpretation of the PSD provisions of the CAA because the interpretation had the effect of applying the PSD requirements to large numbers of small sources that previously had not been subject to PSD, and because, according to the Court, the EPA acknowledged that Congress did not intend that such sources be subject to the PSD requirements.[618] Commenters appear to interpret this decision to preclude the EPA from including at

[618] *Util. Air Reg. Group* v. *EPA*, 134 S. Ct. 2427, 2443 (2014).

least building block 3 in the BSER because it includes measures that involve entities (such as RE developers) that do not emit CO_2 and have not previously been subject to the CAA. However, in this rule, the EPA is not attempting to subject any entity other than the affected EGUs in the source category to CAA section 111 requirements. As discussed below, the EPA is not finalizing the proposed portfolio approach, under which states were authorized to include, in their CAA section 111(d) state plans, federally enforceable requirements on entities other than affected EGUs. Thus, as noted above, this final rule does not require or authorize the states to include entities other than affected EGUs in their CAA section 111(d) state plans, and as a result, those entities will not come under CAA jurisdiction[619] and the parts of the economy that they represent will not be regulated by the EPA.

7. Relative Stringency of Requirements for Existing Sources and New, Modified, and Reconstructed Sources

Commenters also objected that the proposed CAA section 111(d) standards are more stringent than the standards for new, modified or reconstructed sources, and they assert that setting CAA section 111(d) standards that are more stringent than CAA section 111(b) standards would be illogical, contrary to precedent, contrary to the intent of the remaining useful life exception, and arbitrary and

[619] States may regulate non-affected EGUs through a state measures approach, but those regulations would not be federally enforceable.

capricious.[620] We disagree with these comments. Comparing the control requirements of the two sets of rules, CAA section 111(d) and 111(b), is an "apples-to-oranges" comparison and, as a result, it is not possible—and it is overly simplistic—to conclude that the CAA section 111(d) requirements are more stringent than the CAA section 111(b) requirements.

Most importantly, the two sets of rules become applicable at different points in time and have significantly different compliance periods. The CAA section 111(b) rule becomes applicable for new, modified and reconstructed sources immediately upon construction, modification, or reconstruction and, in fact, by operation of CAA section 111(e) and (a)(2), new, modified, or reconstructed sources that commenced construction prior to the effective date of the CAA section 111(b) rule must also be in compliance upon the effective date of the rule. In contrast, the requirements under the CAA section 111(d) rule do not become applicable to existing affected EGUs until seven years after promulgation of the rule, when the interim compliance period begins in 2022, and the final compliance period does not begin until 2030. Moreover, the compliance period for the interim requirements is eight years. This later applicability date and longer compliance period for existing sources accommodates a requirement that, on average, those sources have a lower nominal emission limit than the standards for new or modified sources, which those latter sources must comply with immediately.

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[620] ACC et al. (Associations) comments at 40, Luminant comments at 89.

In addition, the timetables for compliance with the CAA section 111(b) and 111(d) rules should be considered in light of the 8-year review schedule required for CAA section 111(b) rules under CAA section 111(b)(1)(B). Under CAA section 111(b)(1)(B), the EPA is required to "review and, if appropriate, revise" the CAA section 111(b) standards "at least every 8 years." This provision obligates the EPA to review the CAA section 111(b) rule for CO_2 emissions from new, modified, and reconstructed power plants by the year 2023. That mandatory review will reassess the BSER to determine the appropriate stringency for emission standards for new, modified, and reconstructed sources into the future. Therefore, for present purposes of comparing the stringency of the CAA section 111(b) and 111(d) rules, the year 2023 presents an important point of comparison.

Specifically, as noted above, the CAA section 111(b) standards apply to new, modified and reconstructed sources beginning in 2015, while the CAA section 111(d) rule does not take effect until 2022, which happens to fall on the cusp of the 8-year review for the CAA section 111(b) standards.

Even after the section 111(d) rule takes effect in 2022, the flexibility that this rule offers the states has important implications for its stringency and for any comparison to the CAA section 111(b) rule. Although the requirements for the CAA section 111(d) rule begin in 2022, they are phased in, in a flexible manner, over the 2022–2030 period. That is, states are required to meet interim goals for the 2022–2029 period by 2029, and the final goals by 2030, but states are not required to impose requirements on their sources that take effect in 2022. In fact, states may, if they prefer, impose business-as-usual emission standards on their sources that do not require emission reductions in 2022 and apply emission standards on their sources that do require emission reductions and that take effect no earlier than 2023. Moreover, because emission standards may have an annual compliance period, the states may allow their sources to delay having to comply with any emission reduction requirements until the end of 2023.[621]

Therefore, while the CAA section 111(b) standards apply to new, modified, and reconstructed sources beginning in 2015, the CAA section 111(d) standards may not apply to existing sources until 2023. As a result, by 2023—the year that the CAA section 111(b) standards are required to be reviewed for possible revision—affected EGUs subject to the CAA section 111(d) standards may remain uncontrolled. Under those circumstances, the CAA section 111(d) rule cannot be said to be more stringent than the CAA section 111(b) rule.[622]

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[621] A state that chooses to allow its sources to remain uncontrolled through 2023 would still be able to meet its interim goal by 2029, although it would need to impose more stringent requirements on its sources over the 2024–2029 period than it would if it had imposed requirements beginning in 2022. It should also be noted that in fact, most states could allow their sources to remain uncontrolled for 2022 and 2023, and require controls beginning in 2024, and still be able to meet their interim goal.

[622] In addition, because the section 111(d) requirements are phased in, states may choose to apply a gradual phase-in of the reductions. This means that the nominal emission rates for section 111(d) sources would be significantly less stringent for the first several years of the compliance period. We estimate that if states choose to impose the section 111(d) requirements in a

Another reason why the section 111(d) rule cannot be said to be more stringent than the section 111(b) rule is that for any individual source, the section 111(d) rule is applied more flexibly and includes more flexible means of compliance. Whereas the CAA section 111(b) rule entails an emission rate that each affected EGU must meet on a 12-month (rolling) basis, the CAA section 111(d) is more flexible. For example, states may adopt the state measures approach and refrain from imposing any requirements on their affected EGUs. In addition, under the CAA section 111(d) rule, sources have more flexible means of compliance. For an emission standards approach, depending on the form of the state requirements (mass-based or rate-based), the state may be expected to authorize trading of mass-based emission allowances or rate-based emission credits, and in addition, the purchase of ERCs. These flexibilities are not included in the CAA section 111(b) rule, rather, as noted, each new, modified, and reconstructed EGU must individually meet its emission standard on a 12-month (rolling) basis. The EPA has frequently required that sources meet a more stringent nominal limit when they are allowed compliance flexibility, particularly, the

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proportional amount each year, beginning in 2022, the requirements for steam generators by 2022 would result in an average emission performance rate of 1,741 lb. CO_2/MWh net and by 2023, an average emission rate of 1,681 lb. CO_2/MWh net (In 2030, the rate falls to 1,305 lb. CO_2/MWh net.) For existing NGCC units, if states choose to implement the section 111(d) requirements proportionally, in 2022, the average rate would be 898 lb. CO_2/MWh net, and in 2023 it would be 877 lb. CO_2/MWh net. (In 2030, this rate falls to 771 lb. CO_2/MWh net.)

opportunity to trade.[623] In addition, states have the discretion to allow their sources to meet emission standards over a longer time period. This distinction between the two rules is another reason why the CAA section 111(d) rule cannot be said to be more stringent in fact than the CAA section 111(b) rule.

There are other reasons why the CAA section 111(d) rule cannot be said to be more stringent. With respect to the CAA section 111(d) and 111(b) rules for existing and new NGCC units, we note the following: As explained in the CAA section 111(b) preamble, the standard for new NGCC units is designed to accommodate a wide range of unit types, including small units and rapid-start units, which are a small part of the expected new NGCC generation capacity. As such, the CAA section 111(b) standard (1,000 lb CO_2/MWh gross, which equates to 1,030 lb CO_2/MWh net) will not constrain the emissions of the great majority of expected new NGCC generation capacity,

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[623] *See, e.g.*, EPA, "Improving Air Quality with Economic Incentive Programs," EPA-452/R-01-001, at 82 (2001) (requiring that Economic Incentive Programs show an environmental benefit, such as "reducing emission reductions generated by program participants by at least 10 percent"), available at *http://www.epa.gov/airquality/advance/pdfs/eipfin.pdf*; "Economic Incentive Program Rules: Final Rule," 59 FR 16690 (April 7, 1994) (same); "Certification Programs for Banking and Trading of NO_X and PM Credits for Heavy-Duty Engines: Final Rule," 55 FR 30584 (July 26, 1990) (requiring that for programs for banking and trading of NO_X and PM credits for gasoline, diesel and methanol powered engines, all trading and banking of credits must be subject to a 20 percent discount "as an added assurance that the incentives created by the program will not only have no adverse environmental impact but also provide an environmental benefit.").

which is expected to consist of larger base load units (with a capacity of 100 MW or greater) that are not intended to cycle frequently. Their initial emissions are expected to be below 800 lb. CO_2/MWh gross, their emissions over time may be somewhat higher due to equipment deterioration, and as a result, their PSD permits are expected to include emission limits at approximately the 800 lb. CO_2/MWh gross level. A very small amount of the new NGCC generation is expected to be small units (with a capacity of approximately 25 MW) or rapid-start units. Their initial emissions are expected to be approximately 950 lb. CO_2/MWh gross, their emissions over time are expected to be somewhat higher due to equipment deterioration, and it these units that the standard of 1,000 lb. CO_2/MWh gross is designed to constrain.[624] As a result, the 1,000 lb. CO_2/MWh gross limit applies to all new NGCC units, including the great majority of the expected new capacity consisting of larger, non-rapid start units, even though, as just noted, the great majority of the units are expected to emit at significantly lower emission rates. The CAA section 111(d) standard for existing sources, in contrast, is generally expected to constrain existing NGCC units on average. Moreover, very little of the existing NGCC generation includes small units or, in particular, rapid-start units because the latter are a recently developed technology. To some extent, the same is true for the 111(b) standard for reconstructed NGCC units. The average NGCC rate was

[624] As explained in the 111(b) preamble, any attempt to subcategorize and assign a lower emission limit to larger, non-rapid start NGCC units could cause market distortions.

approximately 850 lb CO_2/MWh gross in 2014 and, as a result, most sources are emitting below the CAA section 111(b) standard for reconstructed sources. For these reasons, too, the CAA section 111(b) standards for new and reconstructed NGCC units cannot be compared to the 111(d) standards for existing NGCC units.[625]

Moreover, even if commenters were correct that the CAA section 111(d) requirements for existing sources are more stringent than the CAA section 111(b) requirements for new sources, that would not, by itself, call into question the reasonableness of either standard. The stringency of the requirements for each source subcategory is, of course, a direct function of the BSER identified for that source subcategory. In this rulemaking, we explain the basis for the BSER for existing sources, and why we do not include certain measures, such as CCS; and in the CAA section 111(b) rulemaking, we explain the basis for the BSER for new sources, and why we do not include certain measures, such as the building blocks. As long as the BSER determination is reasonable and the resulting emission limits meet other applicable requirements, those emission limits are valid, even if the one for new sources is less stringent than the one for existing sources. No provision in section 111, nor any statement in its legislative history, nor any of its case law, indicates that the standards for new sources must

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[625] The section 111(b) standards for modified and reconstructed steam generation units are generally lower than the emission rates of existing stream generation units, but for the reasons explained earlier, those standards cannot be compared to the section 111(d) standards for existing steam generation units.

be more stringent than the standards for existing sources.

C. Building Block 1—Efficiency Improvements at Affected Coal-Fired Steam EGUs

The first category of approaches to reducing CO_2 emissions at affected fossil fuel-fired EGUs consists of measures that improve heat rate at coal-fired steam EGUs. Heat rate improvements are changes implemented at an EGU that increase the efficiency with which the EGU converts fuel energy to electric energy, thereby reducing the amount of fuel needed to produce the same amount of electricity and consequently lowering the amount of CO_2 produced as a byproduct of fuel combustion. Heat rate improvements yield important economic benefits to affected EGUs by reducing their fuel costs.

An EGU's heat rate is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output.[626] In 2012, the generation-weighted average annual heat rate of the 884 coal-fired EGUs included in EPA's building block 1 analysis was approximately 9,732 Btu per gross kWh.[627] Because an EGU's CO_2 emissions are driven primarily by the amount of fuel consumed,

[626] Typically, the units of measure used for heat rate (*e.g.*, Btu/kWh-net) indicate whether a given value is based on the gross output or net output. Net heat rate is always higher than gross heat rate; in coal-steam units, net heat rate can be 5–10% higher than gross heat rate.

[627] Similarly, within each interconnection, the generation-weighted average annual heat rates for those coal-fired EGUs in our study population were 9,700 Btu per gross kWh (Eastern); 9,888 Btu per gross kWh (Western); and 9,789 Btu per gross kWh (Texas).

improving (*i.e.*, decreasing) heat rate at a coal-fired EGU inherently reduces the carbon-intensity of generation.

As discussed above in section V.A and in the June 2014 proposal,[628] it is critical to recognize that affected coal-fired EGUs operate in the context of the integrated electricity system. Because of this reality, applying building block 1 in isolation can result in a "rebound effect" that undermines the emissions reductions otherwise achieved by heat rate improvements. As already noted, the building block 1 measures described below cannot by themselves constitute the BSER because the quantity of emission reductions achieved—which is a factor that the courts have required EPA to consider in determining the BSER—would be of insufficient magnitude in the context of this pollutant and this industry. The potential rebound effect, if it occurred, would exacerbate the insufficiency of the emission reductions. However, applying building block 1 in combination with other building blocks can address this concern for the reasons stated in section V.A.4.

We conducted several analyses to assess the potential for heat rate improvements from the coal-fired EGU fleet. As in the proposal, we employed a unit-specific approach that compared each EGU's performance against its own historical performance in lieu of directly comparing an EGU's performance against other EGUs with similar characteristics. Accordingly, as described below, our method effectively controls for the characteristics and factors of an EGU that typically remain constant over time

[628] *See, e.g.*, 79 FR 34830, 34859 (June 18, 2014).

(*e.g.*, a unit is unlikely to dramatically increase or decrease in size). Our methodology for determining the amount of heat rate improvement appropriately included in the BSER as building block 1 is discussed in the next section, below.

1. Summary of Measures Comprising the BSER in Building Block 1

a. *Measures under building block 1—heat rate improvements.*

In finalizing the building block 1 portion of this rule, we considered over a thousand individual comments from the public, including individual EGUs and state agencies, on heat rate improvement, which are discussed below and also in the responses to comments document and the GHG Mitigation Measures TSD for the CPP Final Rule. Based on these public comments, we have refined the statistical analyses used in the proposal to identify the potential heat rate improvement that can be achieved on average by affected coal-fired EGUs.

In the proposal, we used two approaches to analyze the variability of an EGU's gross heat rate using a robust dataset comprised of 11 years of hourly gross heat rate data for 884 coal-fired EGUs—over 11 million hours of data collected between 2002 and 2012. The foundation of our first approach was an analysis of the variability of each EGU's gross heat rate, which was accomplished in large part by grouping each EGU's hourly data by similar ambient temperature and capacity factor (*i.e.*, hourly operating level as a percentage of nameplate capacity) conditions. The second approach analyzed the difference between an EGU's average gross heat rate and its best historical gross heat rate performance. We proposed that, on a nationwide basis, affected coal-fired EGUs should be able to achieve 6-percent heat rate improvement: 4-percent improvement from best practices, and an additional 2-percent improvement from equipment upgrades.

We received many comments asserting that the 11-year dataset we had used to determine the 4-percent best practices figure likely reflected some portion of the 2-percent equipment upgrades figure we had separately identified. Accordingly, these commenters claim that the EPA double-counted equipment upgrades in arriving at the full estimate of 6-percent heat rate improvement. Commenters also noted the difficulty, in some cases, of determining whether a heat rate improvement measure is an "equipment upgrade" or "best practice," such as optimizing soot blowing with intelligent systems, using CO monitors for optimizing combustion, or applying air heater and duct leakage controls.

As noted below in sections V.C.1.b and V.C.3, the EPA acknowledges that some equipment upgrades implemented by EGUs during the 11-year study period are reflected in the hourly heat rate data. Therefore, we made two refinements to our analyses of heat rate improvement potential. First, we refined our statistical approaches to use each EGU's gross heat rate from 2012—the final year of the 11-year study period—as the baseline for calculating heat rate improvement potential. By comparing each EGU's best historical gross heat rate with its 2012 gross heat rate, our analyses account for the enduring effects on heat rate of any equipment upgrades or best practices that an EGU implemented during the study period.

Heat rate improvement measures that an EGU maintains in 2012 are reflected in that baseline, and thus are not treated as evidence that the EGU can further improve heat rate. Additionally, in part because of limitations on the information available to us regarding which equipment upgrades have been or could be implemented at individual EGUs, as well concerns about double-counting, we have conservatively decided not to add a separate equipment upgrade component to our estimate of heat rate improvement potential. Nonetheless, we remain confident that additional equipment upgrades (including measures that are unambiguously equipment upgrades, such as turbine overhauls) are possible at many coal-fired EGUs, as supported by numerous commenters, the Sargent & Lundy study [629] (S&L) and other industry reports and studies. Many of these reports and studies are referenced in the TSD developed for the proposed rule, as well as in the GHG Mitigation Measures TSD supporting the final CPP.

Several commenters criticized the fact that the proposal assessed potential heat rate improvement on a nationwide basis. These commenters suggested instead that we narrow the geographic scope of our analysis, generally identifying a state-by-state approach as a preferred alternative. In light of commenters' concerns about using a single nationwide approach, as well as for reasons described in Section

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[629] Sargent and Lundy 2009, Coal-Fired Power Plant Heat Rate Reductions, SL-009597, Final Report, January 2009, *available at: http://www.epa.gov/airmarkets/documents/ipm/coalfired.pdf*.

V.A and elsewhere in this preamble, the final rule assesses potential heat rate improvement regionally, within the Eastern, Western and Texas Interconnections.[630]

For the final rule, we performed several analyses to determine what heat rate improvement was achievable in each interconnection from best practices and equipment upgrades. As in the proposal, these analyses used the 11-year dataset of EGU hourly gross heat rate data from 2002 to 2012. As discussed further in the GHG Mitigation Measures TSD, our reliance on these gross heat rate data was reasonable given that (1) these data are the only comprehensive data available to the EPA, and (2) heat rate is proportional to CO_2 emission rate.

As in the proposal, we used more than one analytical method to evaluate the opportunity for EGUs to reduce their CO_2 emissions through heat rate improvements. Our final methodology uses three different analytical approaches based on refinements of the two approaches described at the proposal stage. We call these final approaches: (1) The "efficiency and consistency improvements under similar conditions" approach; (2) the "best historical performance" approach; and (3) the "best historical performance under similar conditions" approach. As described below and in the GHG Mitigation Measures TSD, each approach provides an independently reasonable way

[630] The geographic area within the Texas Interconnection generally corresponds to the portion of the state of Texas covered by ERCOT (the Electric Reliability Council of Texas). Additional portions of the state of Texas are located within the Eastern and Western Interconnections.

to estimate the potential for heat rate improvements by EGUs in each region. However, rather than select a potential heat rate improvement value supported by one or only some of these independently reasonable analytical approaches, we conservatively based our final determination for each region on the value for that region supported by all three approaches.

The "efficiency and consistency improvements under similar conditions" approach is a slight refinement of an approach discussed at length in the proposal. As in the proposal, we distributed each hour of gross heat rate data for each EGU into a matrix comprised of 168 bins, based on the ambient temperature and hourly capacity factor of the EGU at the time that hour of gross heat rate data was generated. Each bin represented a 10-degree Fahrenheit (°F) range in ambient temperature (from -20 °F to greater than 110 °F), and a 10-percent range in capacity factor (from 0 percent to greater than 110 percent[631]). Thus, for example, one bin would contain all of an EGU's hourly gross heat rate data generated during the 11-year study period while that EGU was operating at 80- to 89-percent capacity while ambient temperatures were between 70 °F and 79 °F.

As we explained at proposal and as discussed further in the GHG Mitigation Measures TSD, ambient temperature and hourly capacity factor are important conditions that influence heat rate at individual EGUs. By separating the EGU-specific

[631] Because an EGU's rated nameplate capacity is based on a maximum continuous rating, EGUs may operate for periods of time "over" 100 percent of their capacity factor. The EPA's dataset of hourly operating data reflected some such instances.

data into bins based on these variables, and only directly comparing data within a bin, we were largely able to control for the influence of those variables on an EGU's heat rate. Accordingly, having controlled for these two external factors, and having already controlled for unit-specific factors affecting heat rate by analyzing the data for each EGU in isolation, we are confident that the remaining variation in each bin's data was primarily driven by factors under the EGU operator's control.

After allocating an individual EGU's data across the bins, we next established a benchmark for each bin based on the best hourly gross heat rate accounting for outliers (*i.e.*, we set the benchmark at the 10th percentile hourly gross heat rate value) during any consecutive two-year period.[632] We compared the hourly gross heat rate data within each bin to the EGU's benchmark value. Similar to the proposal, within each bin we assessed the effect on heat rate of improving the consistency of that EGU by reducing hourly gross heat rate values that were greater than the benchmark by a percentage of the distance between each of those higher hourly values and the benchmark.[633] We refer to this percentage improvement value as the "consistency factor," because applying it results in values for heat rate that

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[632] As described below, we also conducted this regionalized approach using a benchmark based on the best hourly gross heat rate accounting for outliers during any one-year period. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[633] In the proposal, we used heat input values rather than gross heat rate values. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

are more consistent with the EGU's benchmark for that bin. In our proposal we evaluated the heat rate improvement that would result from applying consistency factors of 10, 20, 30, 40 and 50 percent of the distance between those less-efficient hourly gross heat rate values and the benchmark; using engineering judgment, we selected a consistency factor of 30 percent, which produced results comparable to those obtained using other approaches for analyzing heat rate. For our final analysis under this approach, we refined the consistency factor based on a statistical assessment of the overall variability of heat rate in that EGU's region, as described in the GHG Mitigation Measures TSD.[634] As in the proposal, we applied the consistency factor to each bin of each EGU's hourly gross heat rate data, and averaged the result across all bins in that EGU's matrix. The net result was an improved gross heat rate reflecting what that EGU would have achieved between 2002 and 2012 if, under certain ambient temperature and capacity factor conditions, the EGU had improved its gross heat rate during less-efficient hours to be slightly more consistent with the relevant benchmark value. We then compared the improved gross heat rate for each EGU to its actual 2012 historical average gross heat

[634] For the Eastern Interconnection, the consistency factor is 38.1 percent. For the Western Interconnection, the consistency factor is 38.4 percent. For the Texas Interconnection, the consistency factor is 37.1 percent. Conducting this analysis on a nationwide basis would have resulted in application of a consistency factor of 38.2 percent. As described below, we also conducted this regionalized approach using consistency factors determined based on one-year figures. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

rate. We chose 2012 as the year of comparison because 2012 was the latest year for which the EPA had data at the time of the proposal, and because using the most recent data reflects the EGU's current operating level and accounts for improvements the EGU may have undertaken over the 11-year study period.

Applying this procedure to all units in our database and averaging the generation-weighted results, we determined that it would be reasonable to conclude that, through application of best practices and equipment upgrades, EGUs on average are at least capable of reducing their CO_2 emissions by improving heat rate 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection.[635]

In addition to the statistical approach described above, we employed a "best historical performance" approach refined from the proposal, which compared each EGU's best two-year rolling average gross heat rate to that EGU's 2012 average annual gross heat rate.[636] We then calculated the differences across all EGUs in a region to determine the potential heat rate improvement that would result if, in 2012, each EGU had performed at the best two-year rolling average

[635] Conducting this analysis on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.0 percent. See the table in this section and the GHG Mitigation Measures TSD for the results of this approach using benchmarks and consistency factors based on one-year averages.

[636] As described below, we also conducted this regionalized approach using each EGU's best one-year rolling average. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

gross heat rate that the EGU achieved between 2002 and 2012. Under this analysis of historical gross heat rate, we determined that it would be reasonable to conclude that the average heat rate improvement potential from best practices and equipment upgrades is at least 4.9 percent in the Eastern Interconnection, 2.6 percent in the Western Interconnection and 3.1 percent in the Texas Interconnection.[637]

Finally, we employed the "best historical performance under similar conditions" approach, which combines aspects of the other two approaches. First, as with the "efficiency and consistency improvements under similar conditions approach," we grouped hourly data for each EGU by ambient temperature conditions and hourly capacity factor. Next, we calculated each EGU's best two-year gross heat rate for each of the 168 ambient temperature-capacity factor bins.[638] Similar to the "best historical performance" approach, to calculate the potential heat rate improvement, the EPA then compared each EGU's 2012 gross heat rate for each of the ambient temperature-capacity factor bins to the EGU's best two-year gross heat rate for the corresponding bin.

[637] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 4.6 percent. As described below, we also conducted this regionalized approach using one-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

[638] As described below, we also conducted this approach using one-year averages for each EGU instead of two-year averages. See the GHG Mitigation Measures TSD supporting the final CPP for more details.

Accounting for differences in ambient temperature and capacity factor, we determined that under this analytical approach the average heat rate improvement potential from best practices and equipment upgrades was at least 5.3 percent in the Eastern Interconnection, 3.1 percent in the Western Interconnection and 3.5 percent in the Texas Interconnection.[639]

As in the proposal, we additionally analyzed the data with our analytical approaches using one-year averaging periods in place of the two-year averaging periods described above.[640] However, because our conservative overall methodology adopts the lowest value that is identified for a region by any of our reasonable analytical approaches, the inherently less conservative results obtained with one-year averaging periods (reproduced below) could not influence the outcome of our methodology as a whole. Overall, applying these three analytical approaches resulted in six heat rate improvement values generated for each region, each of which represents a reasonable estimate of the potential for heat rate improvements by EGUs in that region. Those values ranged from 4.3 to 6.9 percent in the Eastern Interconnection, from 2.1 to 4.7 percent in the Western Interconnection, and from 2.3 to 4.9 percent in the Texas Interconnection. In all three regions, the most conservative values were

[639] Conducting this approach on a nationwide basis would have resulted in a finding that EGUs nationwide are capable on average of reducing their CO_2 emissions by improving heat rate 5.0 percent.

[640] The GHG Mitigation Measures TSD describes in more detail our rationale for using one- and two-year averaging periods in our analytical approaches and methodology as a whole.

generated using the "efficiency and consistency improvements under similar conditions" approach with two-year averaging periods and consistency factors. As shown in Table 6, the values produced by that approach were the minimum values for each region produced by any of the three approaches:

TABLE 6—HEAT RATE IMPROVEMENT POTENTIAL BY REGION AND AVERAGING PERIOD

Analytical approach	Heat rate improvement potential (percent) by region and averaging period					
	Western		Texas		Eastern	
	1 year	2 year	1 year	2 year	1 year	2 year
Efficiency and consistency improvements under similar conditions	3.5	2.1	3.7	2.3	5.6	4.3
Best historical performance	4.1	2.6	4.2	3.1	6.3	4.9
Best historical performance under similar conditions	4.7	3.1	4.9	3.5	6.9	5.3