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Environmental Protection Agency

40 CFR Parts 60, 62, and 78
Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 62, and 78

[EPA–HQ–OAR–2015–0199; FRL 9930–67–OAR]

RIN 2060–AS47

Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing a federal plan to implement the greenhouse gas (GHG) emission guidelines (EGs) for existing fossil fuel-fired electric generating units (EGUs) under the Clean Air Act (CAA). The EGs were proposed in June 2014 and finalized on August 3, 2015 as the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (also known as the Clean Power Plan or EGs). This proposal presents two approaches to a federal plan for states and other jurisdictions that do not submit an approvable plan to the EPA: a rate-based emission trading program and a mass-based emission trading program. These proposals also constitute proposed model trading rules that states can adopt or tailor for implementation of the final EGs. The federal plan is an important measure to ensure that congressionally mandated emission standards under the authority of the CAA are implemented. The proposed federal plan is related to but separate from the final EGs. The final EGs establish the best system of emission reduction (BSER) for applicable fossil fuel-fired EGUs in the form of a carbon dioxide (CO_2) emission performance rate for steam-fired EGUs and a CO_2 emission performance rate for natural gas-fired combined cycle (NGCC) units, and provide guidance and criteria for the development of approvable state plans. The purpose of the proposed federal plan is to establish requirements directly applicable to a state's affected EGUs that meet these emission performance levels, or the equivalent statewide goal, in order to achieve reductions in CO_2 emissions in the case where a state or other jurisdiction does not submit an approvable plan. The stringency of the emission performance levels established in the final EGs will be the same whether implemented through a state plan or a federal plan. The EPA is also proposing enhancements to the CAA section 111(d) framework regulations related to the process and timing for state plan submissions and EPA actions. The EPA intends to finalize both the rate-based and mass-based model trading rules in summer 2016.

DATES: *Comments.* Comments must be received on or before January 21, 2016.

Public Hearing. The EPA will hold public hearings on the proposal. Details will be announced in a separate **Federal Register** document.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2015–0199, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

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

Docket: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2015–0199. The EPA has previously established a docket for the January 8, 2014, Clean Power Plan proposal under Docket ID No. EPA–HQ–OAR–2009–0559. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the EPA Docket Center EPA/DC, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

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

SUPPLEMENTARY INFORMATION:

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

ANSI American National Standards Institute
ARP Acid Rain Program

ATCS Allowance Tracking and Compliance System
BSER Best system of emission reduction
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CARB California Air Resources Board
CBI Confidential Business Information
CEIP Clean Energy Incentive Program
CEMS Continuous emissions monitoring system
CFCs Chlorofluorocarbons
CISWI Commercial Industrial Solid Waste Incinerators
CFR Code of Federal Regulations
CHP Combined heat and power
CO_2 Carbon dioxide
CO_2e Carbon dioxide equivalent
CSAPR Cross-state Air Pollution Rule
DOE U.S. Department of Energy
DOI U.S. Department of the Interior
DOL U.S. Department of Labor
DS–EE Demand-Side Energy Efficiency
EE Energy efficiency
EGs Emission Guidelines
EGU Electric generating unit
EIA Energy Information Administration
EJ Environmental justice
EM&V Evaluation, measurement, and verification
EPA Environmental Protection Agency
EO Executive Order
ERC Emission rate credit
FERC Federal Energy Regulatory Commission
FIP Federal implementation plan
FR Federal Register
GHG Greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GJ/h Gigajoule per hour
HAP Hazardous air pollutants
ICR Information collection request
IGCC Integrated gasification combined cycle facility
IPM Integrated Planning Model
IPCC Intergovernmental Panel on Climate Change
ISO/RTO Independent System Operator/ Regional Transmission Organization
lbs Pounds
LML Lowest measured $PM_{2.5}$ levels
MATS Mercury and Air Toxics Standards
M&V Measurement and verification
MMBtu/h Million British Thermal units per hour
MSW Municipal solid waste
MW Megawatts
MWh Megawatt-hours
NAAQS National Ambient Air Quality Standards
NAICS North American Industrial Classification System
NERC North American Electric Reliability Corporation
NGCC Natural gas combined cycle
NSPS New source performance standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
NODA Notice of data availability
NO_X Nitrogen oxides
OAP Office of Atmospheric Programs
OAQPS Office of Air Quality Planning and Standards
PRA Paperwork Reduction Act
PSD Prevention of significant deterioration
PUC Public Utility Commission
RCT Randomized control trials
RE Renewable energy
REC Renewable Energy Certificate
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory impact analysis
RPS Renewable Portfolio Standard
SCT Stationary combustion turbine
SGU Steam generating unit
SIP State implementation plan
SO_2 Sulfur dioxide
TRM Technical Reference Manual
TSD Technical support document
The Court U.S. Court of Appeals for the District of Columbia Circuit
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
UNFCCC United Nations Framework Convention on Climate Change
U.S. United States
WWW World Wide Web

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

I. General Information

A. Executive Summary

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

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

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

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

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

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

section I.B of this preamble. We invite comment on which approach, *i.e.,* either mass-based or rate-based trading, should be selected if we opt to finalize a single approach.

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

A state program that adheres to the model trading rule provisions specified in this rulemaking would be presumptively approvable. States may submit means of meeting the EGs' requirements that differ from the model trading rule provisions, so long as the state demonstrates to the EPA's satisfaction in the state plan submittal that such alternative means of addressing requirements are at least as stringent as the presumptively approvable approach described here.[2] Additionally, there are stand-alone portions of the model trading rules, such as the evaluation, measurement, and verification (EM&V) procedures, that would be approvable even if a state adopted an approach that differs from the federal plan. The model trading rules serve as a mechanism to facilitate larger trading markets since consistency with the federal plan allows trading across both the state and federal programs. The EPA expects a larger trading region is likely to result in lower overall costs. These and other aspects of the model trading rules and federal plan provide additional support for this rule as proposed. Thus, the proposed rule would ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented, either by the states in the first instance, or by the EPA where needed.

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

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

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

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

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

The EPA outlined and initiated the Clean Energy Incentive Program (CEIP) in the final EGs (see section VIII of the final EGs). The program is designed to

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

incentivize investment in certain types of renewable energy (RE) projects, as well as demand-side energy efficiency (EE) projects implemented in low-income communities, that generate MWh or reduce end-use energy demand during 2020 and/or 2021. The EPA proposes to apply the CEIP in all states subject to either a rate-based or mass-based federal plan.

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

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

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

B. Organization and Approach for This Proposed Rule

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

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

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

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

1. The Rate-Based Approach

In the first approach, the EPA would implement a rate-based emissions trading program. In a rate-based program, affected EGUs must meet an emission standard, derived from the EGs, expressed as a rate of pounds of CO_2 per megawatt hour (lbs/MWh). If sources emit above their assigned rate, they must acquire a sufficient number of emission rate credits (ERC), each representing a zero-emitting megawatt hour (MWh), to bring their rate of emissions into compliance. Emission rate credits (ERCs) may be generated by affected EGUs or by other entities that supply zero- or low-emitting electricity resources to the grid through an approval and recognition process that

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

the EPA will administer. ERCs may be bought and sold, or banked for use in later years. The rate-based approach is explained in greater detail in section IV of this preamble.

2. The Mass-Based Approach

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

3. Other Proposed Actions

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

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

C. Who does the Proposed Action apply to?

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

TABLE 1—EXAMPLES OF POTENTIALLY REGULATED ENTITIES[a]

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

[a] Includes NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).
[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a general guide for identifying entities likely to be affected by the proposed action. Whether an affected EGU is affected by this action is described in the applicability criteria in 40 CFR 60.5845 and 60.5850 of subpart UUUU. Questions regarding the applicability of this action to a particular entity should be directed to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

1. What is an affected electric utility generating unit?

For the federal plan, the definition of an affected EGU is identical to the definition in the final Clean Power Plan. Additionally, the applicability of the federal plan is consistent with the EGs, where an affected EGU subject to the federal plan is any steam generating unit (SGU), integrated gasification combined cycle (IGCC), or stationary combustion turbine (SCT) that was in operation or had commenced construction as of January 8, 2014,[5] and that meets certain criteria, which differ depending on the type of unit. The criteria to be an affected EGU are as follows: A unit, if it is a SGU or IGCC, must serve a generator capable of selling greater than 25 MW (Megawatts) to a utility power distribution system, have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel), and historically have supplied more than ⅓ of its potential electric output and 219,000 MWh as net-electric sales on any 3 calendar year basis. If a unit is a SCC, the unit must meet the definition of a combined cycle or combined heat and power (CHP) combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, have a base load rating of greater than 260 GJ/h (250 MMBtu/h), and historically have combusted more than 90 percent natural gas on a heat input basis on an annual basis.

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

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

2. How To Determine if a Unit Is Covered By an Approved and Effective State Plan

Section 111(d) of the CAA, as amended, 42 U.S.C. 7411(d), authorizes the EPA to develop and implement a federal plan for affected EGUs upon the EPA's action finding a failure to submit or disapproving a state plan.[6] The affected EGUs covered in EPA-approved state plans are not subject to the federal plan. If the federal plan has been put in place in a state, but is later replaced by an EPA-approved state plan, the affected EGUs would become subject to the state plan as of the effective date specified in a **Federal Register** notice regarding the EPA's approval of the state plan. The EPA is not expecting state plans to be submitted by the states that submit negative declarations. However, in the event that there are later determined to be affected EGUs located in these states, the final federal plan would be applied to such EGUs through a future action. Part 62 of title 40 of the CFR identifies the status of approval and promulgation of CAA section 111(d) state plans for designated facilities in each state. Recognizing the urgent need for actions to reduce GHG emissions, and in accordance with the Presidential Memorandum,[7] as well as the benefit of providing states with model trading rule options to consider as they prepare their state plans, the EPA is proposing this rulemaking concurrently with the Administrator's signing and promulgation of the final Clean Power Plan EGs. 40 CFR part 62 is updated only once per year. Thus, if 40 CFR part 62 does not indicate that your state has an approved and effective plan after the compliance date has passed requiring state plan submittal, you should contact your state environmental agency's Air Director or your EPA Regional Office (see Table 2 in section II.B of this preamble) to determine if approval occurred since publication of the most recent version of 40 CFR part 62.

D. What should I consider as I prepare my comments?

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

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

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

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

II. Background Information

A. What is the regulatory development background for this proposed rule?

On August 3, 2015, the EPA finalized the Clean Power Plan EGs for existing fossil fuel-fired EGUs (40 CFR part 60, subpart UUUU) under authority of section 111 of the CAA (79 FR 34950). The Guidelines apply to existing fossil fuel-fired EGUs, *i.e.,* those that were in operation or had commenced construction before January 8, 2014. States with existing EGUs subject to the EGs are required to submit to the EPA by September 6, 2016, a state plan that implements the EGs. States may also make initial plan submittals in lieu of a complete state plan, in which case extensions will be granted until September 6, 2018 (40 CFR part 60, subpart UUUU).[8] As discussed in section VI.D of this preamble, Indian Tribes may, but are not required to, submit tribal plans. Once the EPA finds that a state has failed to submit a plan, or disapproves a state plan,[9] section 111 of the CAA and 40 CFR 60.27 require the EPA to develop, implement, and enforce a federal plan for existing EGUs located in that state. In addition, CAA section 301(d)(2) authorizes the Administrator to treat an Indian Tribe in the same manner as a state for this EGU requirement. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). As discussed in section VI.D of this preamble, the agency in this action is proposing a necessary or appropriate finding for the affected EGUs in several areas of Indian country and is proposing the federal plan for these affected EGUs.

The agency believes it is appropriate to propose the federal plan at this time for any states that may ultimately be found to have failed to submit a plan, or had their plan disapproved by the EPA. For some states in this situation, the federal plan may be no more than an interim measure to ensure that congressionally mandated emission standards under authority of section 111 of the CAA are implemented until they can get an approved plan in place. Other states may choose to rely on the federal plan and would not need to develop their own plan. This proposal also serves as two proposed model trading rules which states can adopt or tailor for adoption as their state plan. The role of the model rules is discussed in section II.B of this preamble.

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

B. What is the purpose of this proposed rule?

The purpose of this action is two-fold: (1) To co-propose two approaches to a

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

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

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

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

federal plan to implement the Clean Power Plan EGs for affected EGUs operating in any state lacking an approved state plan by the relevant deadlines; and (2) to propose these same approaches as model trading rules for states to consider in developing their own plans.

1. Federal Plan

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

2. Model Trading Rule

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

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

In further support of state use of the model rules, we are drafting the model trading rule so that it can be adopted or incorporated by reference with a minimum of changes that would be necessary to make the rule appropriate for use by states. This way, a state may incorporate by reference the model rule as the state plan, or as the backstop to a state measures plan with few if any adjustments. States may make changes to the model trading rule, so long as they still meet the requirements of the EGs. If the state chooses to tailor or modify the model trading rule such as by expanding the scope of eligibility of projects that may generate ERCs in a rate-based trading program, the EPA may still approve the plan, but the EPA would conduct appropriate review of such provisions for consistency with the EGs and the state would have to demonstrate to the EPA's satisfaction that its alternative provisions are as stringent as the presumptively approvable approach described. We note here, and in the regulatory text of the model trading rule, that the scope of eligibility of proposed ''ERC resources'' for the federal plan is different than the scope of eligibility provided for in the model rule. Thus, all of the language and provisions in the regulatory text relevant to these other ERC resources is relevant only to the proposed model trading rule and not to the federal plan as such (*i.e.,* those ERC resources discussed in section IV.C.3 of this preamble are applicable to the model rule and only metered RE and applicable nuclear are applicable to the federal plan).

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

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

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

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

criteria set out in the final Clean Power Plan EGs.

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

The approach of proposing model trading rules that are identical in all key respects to proposed federal plans that may be promulgated later, is consistent with prior CAA section 111(d) and CAA section 110 rulemakings. For example, the NO_X state implementation plan (SIP) Call model rule at 40 CFR part 96 (63 FR 57356; October 27, 1998) was identical in all meaningful respects with the Federal NO_X Budget Trading Program at 40 CFR part 97 (65 FR 2674; January 18, 2000). And the CAIR model rule in 40 CFR part 96 (70 FR 25339; May 12, 2005) was identical in all meaningful respects with the federal CAIR in 40 CFR part 97 (71 FR 25396; April 28, 2006).[11] While these identical programs for model rules and Federal Implementation Plans (FIPs) were finalized in separate parts of the CFR, the EPA does not see any reason that it could not just as easily propose the federal plan as the model trading rule in the same section of the CFR.[12] If a federal plan were to be finalized for a given state at a later time, this would be reflected in 40 CFR part 62 by cross-reference, along with any modifications or adjustments that may be appropriate at the time of actual promulgation of a federal plan.

TABLE 2—REGIONAL OFFICE CONTACTS

Region	Regional contact	Phone	States and protectorates
Region I	Shutsu Wong, *wong.shutsu@epa.gov*	617–918–1078	Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, Vermont.
Region II	Gavin Lau, *lau.gavin@epa.gov*	212–637–3708	New York, New Jersey, Puerto Rico, Virgin Islands.
Region III	Mike Gordon, *gordon.mike@epa.gov*	215–814–2039	Virginia, Delaware, District of Columbia, Maryland, Pennsylvania, West Virginia.
Region IV	Ken Mitchell, *mitchell.ken@epa.gov*	404–562–9065	Florida, Georgia, North Carolina, Alabama, Kentucky, Mississippi, South Carolina, Tennessee.
Region V.	Alexis Cain, *cain.alexis@epa.gov*	312–886–7018	Minnesota, Wisconsin, Illinois, Indiana, Michigan, Ohio.
Region VI	Rob Lawrence, *lawrence.rob@epa.gov*	214–665–6580	Arkansas, Louisiana, New Mexico, Oklahoma, Texas.
Region VII	Ward Burns, *burns.ward@epa.gov*	913–551–7960	Iowa, Kansas, Missouri, Nebraska.
Region VIII	Laura Farris, *farris.laura@epa.gov*	303–312–6388	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming.
Region IX	Ray Saracino, *saracino.ray@epa.gov*	415–972–3361	Arizona, California, Hawaii, Nevada, American Samoa, Guam, Northern Mariana Islands.
Region X	Dan Brown, *brown.dan@epa.gov*	503–326–6823	Alaska, Idaho, Oregon, Washington.

C. Legal Authority

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

Further, states will remain free, and indeed are strongly encouraged, to submit an approvable state plan even after promulgation of the federal plan for their jurisdictions. The EPA will withdraw the federal plan for a state when that state submits, and the EPA approves, a final plan. *See* 40 CFR 60.5720.

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

This action co-proposes two approaches to the federal plan, both of which also constitute proposed model trading rules that states could adopt as state plans for EPA approval. The EPA currently intends to finalize one or both of the model trading rules by next summer so that they may be available to states as soon as possible to help inform their state plan development efforts prior to the initial submittal deadline of September 6, 2016, and 2 years before the states' final plan deadline of September 6, 2018.[14] If the EPA

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

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

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

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

finalizes the model trading rules in that timeframe, the only direct consequence will be to provide the states certainty as to one or two particular approaches to the design of their state plan that the EPA will approve if adopted in full. The finalization of a model trading rule will not constitute a final action with respect to a federal plan for the affected EGUs in any state. Rather, the proposed federal plan will remain just that, a proposal. The EPA will promulgate a final federal plan for any state only after it has made a finding on a state's failure to submit a plan, or fully or partially disapproved a submitted state plan. The EPA will go through a public notice and comment process before disapproving a submitted and complete state plan, in whole or part. The EPA invites comments on this staged approach to finalizing one or more model trading rules on the one hand (which we currently intend to do in summer 2016), and finalizing federal plans on the other (which we currently intend to do state-by-state upon our taking predicate action on states' plans).

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

Under the framework regulations as proposed to be amended, *see* section VII below, and the final EGs, at 40 CFR 60.27 and 60.5715 and 5760, respectively, the initial timelines for EPA action on state submittals and, potentially, the promulgation of a federal plan will be as follows: The EPA will have 12 months from the date of a state's submission to approve or disapprove that state's plan. The EPA will have 12 months from the date of its action on a state submission to promulgate the federal plan for the EGUs in that state. Under the completeness-criteria process proposed to be added to 40 CFR 60.27, *see* section VII.E below, the EPA would have 6 months from the deadline for a state's submission to notify a state that its submittal does not meet completeness criteria and constitutes a failure to submit a plan. In the case of initial submittals under 40 CFR 60.5765, the EPA will have 90 days from the date the EPA received the initial submittal to notify a state that its initial submittal does not meet the requirements of 40 CFR 60.5765(a). As with state plans, the EPA will have 12 months to promulgate a federal plan from the date of its finding that a state failed to submit a complete and approvable initial submittal. (Formally, such a finding would be that the state failed to submit a state plan.)

The timeframes stated in the previous paragraph reflect the maximum time allowed for EPA action. We note that under CAA section 111(d)(2) and CAA section 110(c), the EPA may promulgate a final federal plan for a state immediately upon making a finding of failure to submit a state plan or initial submittal, or upon making a finding of final disapproval of a state plan. Congress gave the EPA authority in CAA section 111(d)(2), as it did in CAA section 110(c), to promulgate a federal plan at any time after it disapproves or finds a failure to submit a state plan. The Supreme Court has recognized that under this authority, the EPA may promulgate a FIP ''at any time'' within the 2-year limit of CAA section 110(c) ''that begins the moment EPA determines a SIP to be inadequate.'' *EME Homer City* v. *EPA,* 134 S. Ct. 1584, 1601 (2014). ''EPA is not obliged to wait two years or postpone its action even a single day . . . .'' *Id.* It is essential to implement plans for the control of emissions of CO_2 expeditiously and avoid unnecessary delay. Among other reasons, this will provide affected EGUs regulatory certainty and will assist the regulated entities as well as those authorities with responsibility for ensuring grid reliability to have as much time as possible to plan for the 2022 compliance start date set in the EGs. Thus, it is reasonable to propose this federal plan now so that federal plans will be ready to be promulgated quickly in cases where states have failed to submit a plan or their plans are found unsatisfactory.

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

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

In this document, the EPA is proposing regulatory text setting out the substantive provisions for both of the proposed federal plans/model trading rules. The EPA is not providing specific regulatory text that would, if finalized, actually promulgate a federal plan for each state for which this proposed federal plan might be applied.[15] We currently envision that this language would be in the form of a new section to the state-specific subparts of part 62 and would be ministerial in nature. It would likely provide that the affected EGUs in each such state are subject to a federal plan and would then cross-reference or incorporate by reference the substantive provisions of one of the two subparts proposed in this action (if finalized), along with any applicable modifications or adjustments as may be necessary, either based on new information or in response to comments regarding the application of the federal plan to that particular state. This text may appear similar to the FIP language found in the final CSAPR rule (76 FR 48208, 48361–78; August 8, 2011).

E. Use of the Model Trading Rule as a Backstop

As discussed in the final EGs, the EPA believes that either a mass-based or rate-based model trading rule could function well as the federally enforceable ''backstop'' that the EGs require to be included in ''state measures'' type state plans.[16] (The proposed federal plan does not itself require a ''backstop'' because it relies on an ''emission standards'' approach, rather than a ''state measures'' approach, as delineated in the final EGs.) The conditions and requirements for the federally enforceable backstop in a state measures approach are discussed in

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

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

detail in the final EGs. *See* sections VIII.C.3.b and VIII.C.6.c of the final EGs. To summarize those provisions, without reopening them for comment, the federally enforceable backstop must fully achieve the CO_2 emission performance rates or the state's interim and final CO_2 emission goals if the state plan fails to achieve the intended level of CO_2 emission performance. The state plan submittal must identify the federally enforceable emission standards for affected EGUs that would be used in the backstop, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the EGs, and identify all necessary state administrative and technical procedures for implementing the backstop (*e.g.,* how and when the state would notify affected EGUs that the backstop has been triggered). In addition, the backstop emission standards must make up for any shortfall in CO_2 emission performance during a prior plan performance period that led to triggering of the backstop.

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

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

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

Applicability and Enforceability. If promulgated for the affected EGUs in a particular state, this federal plan will require affected EGUs to meet specific emission standards for CO_2 and related requirements. These enforceable compliance obligations will apply to the owners and operators of those affected EGUs. *See* 40 CFR 62.13. No obligation falls on states or state officials (except to the extent they may be owners and operators of affected EGUs).[17] In the event of noncompliance, the provisions in the federal plan are federally enforceable against an affected EGU, in the same manner as the provisions of an approved state plan under CAA section 111(d), and similar to a FIP or an approved SIP under CAA section 110. *See* CAA section 111(d)(2)(B), 42 U.S.C. 7411(d)(2)(B) (power to enforce state and federal plans), section 113(a)–(h), 42 U.S.C. 7413(a)–(h), and section 304, 42 U.S.C. 7604. This means that the Administrator has the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h), and states and other third parties maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA section 304.

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

III. Federal Plan Structure To Achieve Reductions

A. Overview

1. Interactions With State Plans and Scope of Trading

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

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

- The state plan must be approved.
- The state plan must implement the same type of trading program as the federal plan trading program in order to

be linked for interstate trading, *i.e.,* mass-based trading programs can link to mass-based trading programs only, and rate-based trading programs can link to rate-based trading programs only.

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

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

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

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

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

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

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

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

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

2. Addressing Potential Leakage and Interstate Effects

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

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

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

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

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

3. Provisions To Encourage Early Action

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

B. Inventory of Emissions

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

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

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

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

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

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

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Million metric tons carbon dioxide equivalent (MMT CO_2 Eq.)][22]

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

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[24] In 2013, fossil fuel combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[25] Table 4 of this preamble presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (MMT CO_2)[26]

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

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

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS (MMT CO_2e)[27]

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

C. Affected EGUs

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

When considering and understanding applicability, the following definitions may be helpful. Simple cycle

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

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

[24] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[25] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[26] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

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

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

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

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

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

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

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

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

D. Compliance Schedule

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

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

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, ''[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.'' *See e.g.,* June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

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

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

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

E. Addressing Reliability Concerns

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

There are many features of the electricity system that ensure that electric system reliability will be maintained. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, U.S. Department of Energy (DOE), state public utility commissions (PUCs), independent system operators and regional transmission organizations (ISOs/RTOs), and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

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

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

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

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

In the final Clean Power Plan EGs, the EPA laid out the availability of a reliability safety valve that could be used if an unanticipated catastrophic emergency caused a conflict between

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

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

[33] *Id.*

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

maintenance of electric reliability and inflexible requirements that a state plan might impose on an affected EGU or EGUs. Under the federal plan, inflexible requirements are not imposed on specific plants. Rather as explained earlier, the very nature of the federal plan, in which affected EGUs can obtain allowances or credits if needed, supports reliability. Therefore, a reliability safety valve for the federal plan is not needed. The EPA invites comments on this aspect of the proposed federal plan.

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

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

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

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

F. Worker Certification

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

G. Remaining Useful Lives and Potential for ''Stranded Assets''

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

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

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

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

limitation available to meet emission limits were pollution control technology.'' H. Report 94–1175, at 159 (1976) (emphasis added). This language is probative of the fact that Congress viewed ''remaining useful lives'' as a consideration for facilities with relatively little remaining useful life. We are confident the proposed federal plan will not force costly pollution control investments at older plants with short remaining useful lives.

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

This view also accords with past agency practice in implementing a similar provision. In the 1977 Amendments, Congress listed ''remaining useful life'' as a factor for consideration in the visibility program under section 169A. 42 U.S.C. 7491. The ''remaining useful life of the source'' is one of several enumerated factors that the state or the EPA is to consider in determining the best available retrofit technology (BART) for a particular source. Consistent with congressional purpose, the EPA has implemented this factor in the regional haze program for many years through the BART guidelines, in appendix Y to 40 CFR part 51. In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR part 51, appendix Y, section IV.D.4.k. In the agency's view, this approach to ''remaining useful life'' aligns with congressional intent and informs our view of how the ''remaining useful lives'' factor should be considered under this CAA section 111(d) federal plan. The key consideration is whether the time period associated with amortizable costs of compliance will exceed the remaining useful lives of the sources in question.

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

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

By relying on either rate- or mass-based emission trading, the proposed federal plan capitalizes on the inherent flexibility available through market-based techniques. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs or allowances than the second facility. Buying ERCs or allowances as a compliance method could avoid excessive up-front capital expenditures that might be unreasonable for facilities with short remaining useful lives, and therefore addresses the consideration of ''remaining useful lives.'' Buying ERCs or allowances as a compliance method also would reduce the potential for stranded assets.

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

Further, unlike state plans that can be more stringent under CAA section 116, the federal plan is no more stringent than the EGs, and, as explained in the EGs, the Guidelines reflect a reasonable, rather than a maximum possible, implementation level for each building block in order to establish overall goals that are achievable. As discussed in the

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

EGs, the BSER determined an average level of emissions achievable by groups of EGUs, rather than for an individual EGU. In considering the remaining useful lives of facilities under a federal plan, the EPA believes this approach to setting the emission standards, coupled with the ability to trade, adequately accounts for remaining useful lives of facilities. In essence, it allows the facilities to comply with the federal plan through the purchase or acquisition of ERCs or allowances, and to avoid the need to make costly investments in control technology for plants that have short remaining useful lives.[37] For these reasons, the federal plan adequately considers ''remaining useful lives.'' We invite comment on our consideration of facilities' ''remaining useful lives'' in the federal plan.

H. Implications for Other EPA Programs and Rules

1. Title V Permitting

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

The EPA anticipates that, given the nature of the units covered by the proposed federal plan, most of the sources at which they are located are already or will be subject to title V permitting requirements. For sources subject to title V, the requirements applicable to them under the proposed federal plan will be ''applicable requirements'' under title V and, therefore, will need to be addressed in the title V permits. For example, requirements under the proposed federal plan concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to either meet an emission rate (including through holding ERCs (rate-based approach)), or to hold allowances covering emissions (mass-based approach) will be ''applicable requirements'' to be addressed in the permits.

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

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

As a further example of flexibility under title V, and consistent with 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B), the EPA is proposing that any changes that may be required to an operating permit with respect to a trading program under the federal plan may be made using the minor permit modification procedures of the title V rules. The EPA proposes that such changes may include the initial changes needed to the title V permit to establish the applicability of the trading program to the source, specify the covered units, and to include other permit terms that may be needed for implementation, including the general approach for monitoring and reporting. The minor permit modification procedures could also be used for any subsequent changes

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

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

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

to permit terms that may be needed with respect to the trading program, although we expect such changes to be infrequent. As noted above, once a trading program has been established in the permit, there may be transactions, such as individual trades, that will require no formal permit modification procedures because such trading would be already addressed and allowed by the permit (''provided for in the permit'') provided the changes do not conflict with any existing terms of the permit. If a source wishes to make a change that would go against any express term of the permit, the permit must be revised to allow such a change before the source begins operation of the change. Under the implementation strategy described above, the EPA believes it would be unlikely that any change in trading allowances would violate a term of a permit, but this principle is important to keep in mind when deciding if a minor permit modification is appropriate with respect to operating a trading program in the context of a title V permit.

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

The EPA notes that the approach to title V permitting that is being proposed is somewhat similar to the approach adopted in the final CSAPR. *See* 76 FR 48299–48300 (August 8, 2011). The agency recently issued guidance to assist permitting authorities and sources subject to CSAPR in incorporating CSAPR requirements into title V permits.[40] The EPA invites comment on its proposed approach to permitting requirements for the federal plan, including whether it would be of use to develop guidance similar to the guidance developed for permitting under CSAPR. The EPA invites comment on its proposed approach to incorporating applicable requirements of the federal plan into title V permits and revising those requirements, including specifically seeking comment on whether all requirements should be eligible for incorporation into title V permits via minor modification procedures or if only a specified subset of such requirements should be eligible for such procedures.

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

2. Implications for New Source Review Program

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

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

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

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

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

3. Interactions With Other EPA Rules

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other rules recently finalized or proposed by the EPA.[41] These rules include the Mercury and Air Toxics Standards (MATS) (77 FR 9304; February 16, 2012);[42] the CSAPR; Requirements for Cooling Water Intake Structures at Power Plants (79 FR 48300; August 15, 2014); Disposal of Coal Combustion Residuals from Electric Utilities, promulgated on April 17, 2015 (80 FR 21302); and the

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

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

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

proposed Steam Electric Effluent Limitation Guidelines and Standards (78 FR 34432; June 7, 2013). These rules are discussed in more detail in the final EGs along with steps the EPA is taking to enable compliance with obligations under other power sector rules as efficiently as possible. We solicit comment on whether there are specific things the EPA can do in the design and implementation of the federal plan that further this objective.

I. Administrative Appeals Process

Under either a rate-based or mass-based trading program, the EPA anticipates that there may be situations in which individual parties are affected by decisions of the agency. For example, under a rate-based plan, a determination may be made that an eligibility application by an ERC provider is denied. And, for set-asides in the mass-based program, an affected EGU may believe that its allowance allocation amount was miscalculated. Similar to prior trading programs, the agency believes it would be efficient and potentially avoid the need for recourse to litigation to provide an administrative appeals process. Therefore we are proposing, and requesting comment on, the use of the regulations for appeals procedures set forth in 40 CFR part 78, to provide for the adjudication of certain disputes that may arise during the course of implementation of a federal plan under CAA section 111(d). We also propose to revise part 78 to accommodate such appeals. The part 78 procedures cover prior CAA emission trading programs and were specifically designed with these types of disputes in mind.

The persons eligible to file such appeals would be designated representatives as defined in this proposed rule and other ''interested persons'' as defined in part 78. The filing of an appeal and the exhaustion of administrative remedies under part 78 would be a prerequisite to seeking judicial review. For purposes of judicial review, final agency action would occur only when an agency decision under the federal plan listed as appealable under part 78 has been issued, and the procedures of part 78 for appealing the decision are exhausted.

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

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

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

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

J. Consistency of Program Structure With Clean Air Act Authority

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

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

Section 111(d)(2) provides that ''[t]he Administrator shall have the same authority [ ] to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title in the case of failure to submit an implementation plan . . .'' 42 U.S.C. 7411(d)(2)(A).[43]

The phrase ''same authority to prescribe'' indicates that Congress viewed the EPA's authority to issue a federal plan for designated pollutants under CAA section 111(d) as, in some sense, co-extensive with its authority to issue a FIP for National Ambient Air Quality Standards (NAAQS) pollutants under CAA section 110. This authority under CAA section 111, of course, must be understood in reference to the purpose of that section (*i.e.,* to achieve emission reductions for designated pollutants from designated facilities), rather than in reference to the purpose of CAA section 110 (*i.e.,* to attain and

[43] Section 111(d)(2) further provides that ''[i]n promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, the remaining useful lives of the sources in the category of sources to which such standard applies.'' The agency's interpretation of the ''remaining useful lives'' provision is discussed above in section III.G of this preamble.

maintain the NAAQS). However, it has been the agency's longstanding view that, in both procedural and substantive respects, Congress intended that the CAA section 110 authority be looked to under CAA section 111(d)(2). *See* 40 FR 53340, at 53342 (November 17, 1975) (''It is obvious that [the Administrator] could only prescribe standards on some substantive basis. The references to section 110 of the CAA suggest that (as in CAA section 110) [she] was intended to do generally what the states in such cases should have done, which in turn suggests that (as in CAA section 110) Congress intended the states to prescribe standards on some substantive basis. Thus, it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also [her] review of state plans.'').

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

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

Congress gave the EPA the same authority to prescribe a plan under CAA section 111(d)(2) as it possesses under CAA section 110(c). The EPA believes this authority is the ''same'' in the sense described above and in the case law.[44] The scope of the EPA's action to undertake a FIP under CAA section 110 is informed by the scope of the state's action to undertake a SIP; likewise, the scope of the EPA's action to undertake a federal plan under CAA section 111(d) is informed by the scope of the state's action to undertake a state plan.

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

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

2. Use of Market Techniques To Implement Standards of Performance Under the Clean Air Act

The use of market techniques such as emission trading is well-supported in the CAA and has many regulatory precedents. The EPA discussed this history, and the reason why trading is a supportable method of

[44] We interpret the cross-reference to be to the currently enacted version of CAA section 110(c), rather than to a prior version. As discussed in section VII of this preamble, below, the current version of CAA section 110, including subsection (c), reflects changes made in the 1990 Amendments based on experience gained in the first two decades of the CAA's implementation. The statute and legislative history do not expressly address the question, but there is no indication Congress would have intended to prevent these improvements from being available under CAA section 111 as well.

implementation of standards of performance under CAA section 111(d) in the EGs. See section V.A of the final EGs. Here we supplement that discussion with respect to the agency's own authority under CAA section 111(d)(2) to use trading as a method of implementation of a ''standard of performance'' in the federal plan.

The 1990 CAA Amendments added broad authorizations for the use of market techniques in several sections of the statute, including Title I. States were provided express authority to use such approaches in their NAAQS implementation plans under CAA section 110(a)(2)(A): ''Each [state] plan shall include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights) . . . .'' 42 U.S.C. 7410(a)(2)(A). The EPA was given similar authority in the definition of a ''Federal Implementation Plan'' in CAA section 302, which defines that term as an EPA-promulgated plan, which ''includes enforceable emissions limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.'' 42 U.S.C. 7602(y). Section 111(d)(2) of the CAA provides the EPA the same authority to prescribe a federal plan under CAA section 111 as it would have to promulgate a FIP under CAA section 110(c). Thus, the EPA believes the plain language of the statute authorizes the use of market techniques in CAA section 111(d) federal plans.

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

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

With the increasing recognition of the utility of trading, crediting, and averaging to meet emission reduction goals efficiently, the EPA set forth a comprehensive policy on trading in 1986. Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 FR 43814 (December 4, 1986) (hereinafter ''ERC Policy''). In the ERC Policy, the EPA stated that it ''endorses emissions trading and encourages its sound use by states and industry to help meet the goals of the CAA more quickly and inexpensively.'' At the same time, based on lessons learned from its earlier 1982 trading policy, the EPA took steps to tighten its policies on the use of ''bubbles'' to ensure environmental integrity of trading, particularly in nonattainment areas. The agency emphasized the requirements of enforceability, tracking (and preventing double-counting), determining the appropriate baseline from which to measure emissions, and demonstration of actual air quality benefits.

The use of an emissions trading system for CO_2 reductions for affected EGUs under CAA section 111(d) is also analogous to the trading system for chlorofluorocarbons (CFCs) under the pre-1990 CAA provision for control of stratospheric ozone depleting substances. This program was reviewed by the Office of Legal Counsel (OLC) within the Department of Justice in 1989. *See* Memorandum for Alan Raul, General Counsel, Office of Management and Budget, from the Office of the Assistant Attorney General (April 14, 1989) (hereinafter ''OLC Memo'').[46] The OLC was asked by OMB to opine whether a general grant of regulatory authority to the EPA to ''control'' CFCs was sufficient to authorize an emissions fee or a cap-and-trade system, including auction, of tradable allowances. The statute authorized the EPA to issue regulations ''for the control of any substance, practice, process, or activity (or any combination thereof) which in his judgment may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, if such effect in the stratosphere may reasonably be anticipated to endanger public health.'' Former CAA 157(b) (as enacted in the 1977 CAA amendments). The Office of Legal Counsel concluded that this language—which it characterized as ''plain,'' ''unambiguous,'' and ''sweeping''—was sufficient to authorize the EPA to establish a cap-and-trade program with auction for CFCs. *See id.* at 7 (''It cannot seriously be argued that the use of economic incentives to regulate pollution is a novel or strange idea that could not have been anticipated by the authors of the Clean Air Act Amendments [of 1977].'') (citing multiple examples from the policy literature as early as E. Mishan, *The Costs of Economic Growth* (1967)). The OLC noted that as of 1977, ''Congress was cognizant of economic forms of regulation, did not prohibit them, but instead used general language

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

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

permitting a wide scope of regulatory measures for the control of CFCs.'' To interpret the general authority of this section of the CAA as affirmatively prohibiting market incentives would be, in the OLC's words, to read into the statute the italicized clause ''regulations for the control [of CFCs] *by traditional command and control or specification standard methods,*'' *id.* at 9—a rewriting ''unwarranted in any case, but especially so where Congress was aware of economic methods of control and where such methods so ably serve the underlying purposes of the statute.'' *Id.*

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

Since the 1990 Amendments, the EPA has established three of its most robust trading programs—the Federal NO_X Budget Trading Program (65 FR 2674; January 18, 2000), the CAIR (71 FR 25328; April 28, 2006), and the CSAPR (76 FR 48208; August 8, 2011), under CAA section 110(a)(2)(D)(i)(I), relating to air pollution that causes nonattainment or interference with maintenance of air quality standards in downwind states.[48]

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

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

Finally, the Supreme Court has affirmed the breadth of the agency's discretion under CAA section 111(d) to select the method by which it would control CO_2 emissions from existing power plants. *See AEP* v. *Connecticut,* 131 S. Ct. 2527, 2538 (2011) (''Congress delegated to EPA the decision whether *and how* to regulate carbon-dioxide emissions from power plants.'') (emphasis added); *see also id.* at 2539 (''The appropriate amount of regulation in any particular GHG-producing sector cannot be prescribed in a vacuum: As with other questions of national or international policy, informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The CAA entrusts such complex balancing to the EPA in the first instance, in combination with state regulators.'').

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

IV. Rate-Based Implementation Approach

A. Overview

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

This section describes the proposed rate-based federal plan and model trading rule and how each would be designed and operated, consistent with the EGs. For the federal plan, the EPA is proposing to limit the issuance of ERCs to designated categories of affected EGUs and to RE resources and nuclear generation (from new capacity and incremental capacity uprates) that are

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

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

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

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

measured by a revenue quality meter, rather than the full suite of options discussed in the EGs. The EPA requests comment on whether to limit the scope of the federal plan in this manner, and if not, what other sources of low- or zero-emitting electricity in federal plan states should also be eligible to generate ERCs for compliance purposes. For both the proposed federal plan and model rule, the EPA requests comment on which EM&V plan, measurement and verification (M&V) report, and verification report requirements should apply for each eligible resource. Further discussion of non-BSER measures that may be eligible to generate ERCs can be found in the Clean Power Plan and section IV.C.3 of this preamble. (The EPA is not reopening its determination of the BSER.)

B. Rate Goals

In the Clean Power Plan the EPA identified a rate-based ''emission standards'' approach as an approvable method for state plans to implement the final EGs. In this approach the requirements for compliance rest solely on affected EGUs in the form of federally enforceable emission standards expressed as a rate of emissions of CO_2 per unit of energy output. In the Clean Power Plan, the EPA established, through application of the BSER, separate CO_2 emission performance rates for affected EGUs in two subcategories. The two subcategories are natural gas-fired stationary combustion turbines (*i.e.,* natural gas combined cycle units, or NGCC units) and fossil fuel-fired EGUs (*i.e.,* utility boilers and IGCC).[51] The CO_2 emission performance rates set in the Clean Power Plan are reflected below in Table 6 of this preamble. The EPA is proposing to apply these rates in the rate-based federal plan as the emission standards for NGCC units, and SGUs, respectively. For a thorough discussion of affected EGU category-specific CO_2 emission performance rates and rationale, see section VI of the final EGs. These calculated standards and the premises that these standards are based on are not within the scope of comment in this rulemaking as they were finalized in the Clean Power Plan.

As discussed in section III.D of this preamble above, the EPA proposes to implement a compliance schedule for the rate-based federal plan with multi-year compliance periods as follows: A 3-year period (2022 through 2024), followed by a 3-year period (2025 through 2027), followed by a 2-year period (2028 and 2029), for the Interim Period; and, commencing in 2030, successive 2-year compliance periods for the Final Period. In the Clean Power Plan, the EPA established CO_2 emission performance rates for the subcategories of affected EGUs for the performance periods. The EPA proposes to use those emission performance rates promulgated in the Clean Power Plan as the rate-based emission standard for the respective EGUs that would become subject to this proposed federal plan if finalized. The EPA is not opening for comment the determinations made in the Clean Power Plan of each subcategorized CO_2 emission performance rates. The rate-based emission standards for respective EGU types are provided for convenience in Table 6 of this preamble.

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

TABLE 6—GLIDE PATH INTERIM PERFORMANCE RATES (ADJUSTED OUTPUT-WEIGHTED-AVERAGE POUNDS OF CO_2 PER NET MWh FROM ALL AFFECTED FOSSIL FUEL-FIRED EGUS)

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

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

C. Crediting Mechanism

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

Under this proposed federal plan, ERCs will be issued by the EPA to four categories of entities: (1) Affected EGUs that perform at a rate below the applicable rate-based emission standard; (2) affected NGCC units for all generation (represents shifting generation from SGUs to NGCC units, as anticipated under Building Block 2); (3) new nuclear units and capacity uprates at existing nuclear units; and (4) RE providers that develop metered projects and programs whose results, in MWh, are quantified and verified according to

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

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

EM&V criteria as described below in section IV.D.8 of this preamble. We are also discussing in this preamble, requesting comment for the federal plan, and proposing for the model trading rule a potential fifth category: Other low- and zero-emitting non-BSER measures that are described in section IV.C.3 of this preamble. The concept of using an ERC as a crediting mechanism to meet compliance obligations is consistent with the Clean Power Plan EGs and is being adopted in this federal plan.[53]

Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with emission standards. The responsibility for the validity of the ERC rests with the affected EGU. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and EPA issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the EGs. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud. The EPA requests comment on ways that the EPA could safeguard the validity of an ERC.

1. ERCs Generated and Owed Against a Standard

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

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

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

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

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

2. Incremental NGCC ERCs

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

All affected NGCC generation will be credited, with ERCs, by a factor that represents the described emission reductions from incremental generation; ERCs credited in this way will be designated as Gas Shift ERCs (GS–ERCs) for clarity.[55] The collective sum of the GS–ERCs generated realizes the amount of emission reductions described in BB2 when 75 percent capacity is achieved. This incentive is not a requirement, however. If NGCC units do not collectively increase to 75 percent capacity or above, the lost opportunity for ERC generation simply will need to be achieved through other means (*e.g.,* emissions performance improvements at

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

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

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

affected EGUs or additional RE generation). The amount of GS–ERCs the EPA proposes to be generated for every MWh of NGCC operation is set at a factor relating the amount of electricity generation that NGCC units collectively would generate at the level described in BB2 (*i.e.,* reaching 75 percent capacity) and the associated emission reductions. This means that fractional GS–ERCs are generated for every NGCC MWh and when the interconnect region collectively reaches the level that would be generated if all NGGC units in the region operated at a 75 percent capacity factor there will be an amount of GS–ERCs that correlates to the emission reductions anticipated under BB2 of the BSER. NGCC units are expected to be incentivized to reach this level of generation in part due to market demand for GS–ERCs. Thus, GS–ERCs have the potential to play an important role in the sector meeting compliance obligations.

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

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

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

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

The Incremental Generation Factor is a factor that the EPA will calculate and will be calculated for every compliance period based on the least stingent region's Incremental Generation Factor based on increased utilization of RE and its replacement of fossil fuel-fired generation (based on Building Block 3 of the Clean Power Plan EGs).[57] For the calculation of this factor the EPA is using the least stringent region for each compliance period and applying it for all GS–ERC calculations subject to the federal plan. The calculations for determinating the least stringent regional Incremental Generation Factor can be found in the GS–ERC TSD. Table 7 of this preamble presents the proposed values that would apply for all NGCC units to calculate the amount of issued GS–ERCs.

TABLE 7—INCREMENTAL GENERATION FACTORS FOR INTERIM AND FINAL COMPLIANCE PERIODS

Corresponding incremental generation factor			
Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	2030–2031 and thereafter
0.22	0.32	0.28	0.26

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

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

The GS–ERC equation above gives the number of GS–ERCs that an NGCC unit will generate. The Incremental Generation Factor and GS–ERC Emission Factor combine to make the GS–ERC generating rate for the NGCC unit. This functions by the Incremental Generation Factor prorating all incremental NGCC generation and the GS–ERC Emission Factor designating the proportion of the incremental NGCC generation that will generate ERCs. The GS–ERC generating rate multiplied by the total NGCC Generation gives the total GS–ERCs generated by the NGCC unit for the year.

The EPA is proposing this approach, which provides GS–ERCs for all affected EGU NGCC generation but at a fractional, pro rated level, using the three factors above, for several reasons. This approach has the benefit of

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

[57] Note that per the discussion in section VI of the final EGs, if the EPA had measured incremental NGCC generation for reassignment to fossil steam rate as the difference from the post building block three levels and full utilization, the post building block three levels would be used in the numerator here, resulting in a higher ''incremental generation factor'' and more ERCs for the same amount of NGCC generation.

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

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

The EPA also requests comment on whether the GS–ERC Emission Factor should be calculated on a unit by unit basis (as currently proposed) or be calculated based on the least stringent region's baseline 2012 average emission rate. This will simplify the practice of calculating and distributing GS–ERC generation, but would not reward the better performing NGCC units within the subcategory. In the GS–ERC TSD, the EPA used the regions' average emission rate to calculate a factor that would credit GS–ERCs to all NGCC units subject to the federal plan. For 2030 and beyond, this value is based on the Eastern Interconnect and is 0.08 GS–ERCs/MWh. So for every MWh that an NGCC unit generates it would be issued 0.08 GS–ERCs and, if this were the approach the EPA proposed, this would apply to every NGCC unit that would be subject to the federal plan.

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

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

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

$$850{,}000{,}000 \text{ lbs } CO_2/[1{,}000{,}000 \text{ MWh} + \text{ERC MWh}] = 771 \text{ lbs } CO_2/\text{MWh}$$

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

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

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

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

0.45 * 0.26 * 1,000,000 = GS–ERC

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

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

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

$$\text{GS-ERC} = \frac{(\text{Steam Standard} - \text{NGCC Emission Rate})}{\text{Steam Standard}} * \text{Incremental NGCC Generation}$$

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

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

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

3. Eligible Emission Reduction Measures for ERC Generation

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

The EPA is proposing the inclusion of these measure types in the federal plan for the following reasons. These technologies, with the exception of nuclear, are part of the quantification of RE generation potential for the BSER. Thus, they are included in the quantification of CO_2 emission performance rates and should be available to affected EGUs to meet their CO_2 emission performance rate under the federal plan. See the final EGs for details on the treatment of these measures in BSER (see section V.E of the final EGs). These RE technologies are also expected to be able to deploy on an economic basis during the compliance period, as discussed in the final EGs (see section V.E.6 of the final EGs). These technologies also provide the simplest and most timely path for EM&V implementation under a federal plan, because they can use their existing metering infrastructure to quantify generation and submit it for ERC issuance. A concern unique to federal plan implementation is the need for an ERC issuance process that can be implemented in a streamlined manner across many jurisdictions in the time frame allowed by the federal plan while still assuring a rigorous EM&V process. By limiting eligibility to measures that can be directly metered, a feasible federal plan process for ERC issuance across a potentially large number of jurisdictions is ensured. This approach would allow for easier determinations of compliance with the requirements for EM&V proposed in section IV.D.8 of this preamble below (see also section VIII.K.3 of the final EGs).

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

The EPA requests comment on the inclusion of various types of demand-side EE as eligible measures for ERC issuance under the federal plan, such as state and utility EE programs, project-based demand-side EE, state building codes, state appliance standards, and conservation voltage reduction. The agency also requests comment on the inclusion of CHP as an eligible measure under the federal plan. Later in this section, the agency has provided detailed requirements for the issuance of ERCs for CHP, and we request comment on these requirements for inclusion in the federal plan.

The EPA requests comment on the inclusion as eligible for ERC issuance under the federal plan of any other

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

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

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

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

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

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

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

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

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

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

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

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

comment on whether to include a provision that allows sources to seek approval for other types of biomass to be added to the pre-approved list and what that process would entail. For example, this process could include consideration of the production, processing and use of forest- and agriculture-derived biomass fuels and related CO_2 benefits.

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

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

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

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

The electrical generation from a non-affected CHP unit that can be used to adjust the CO_2 emission rate of an affected EGU must be calculated in accordance with the method specified in this section. The CHP unit's electrical output is prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's ''incremental CO_2 emission rate'') compared to a reference CO_2 emission rate.[64] This ''incremental CO_2 emission rate'' related to the electric generation from the CHP unit would be relative to the applicable CO_2 rate-based emission standard for affected EGUs in the state and would be limited to values between 0 and 1. The CHP unit's electrical output is prorated as follows:

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

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

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

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

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

This accounting approach takes into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. To generate ERCs for CHP, the CHP Electrical CO_2 Emission Rate that is calculated (from above) is applied against the applicable affected EGU standards in the same fashion as described in section IV.C.1 of this preamble. The low CO_2 emission rate for electrical generation from a non-affected CHP unit is a product of both the fact that CHP units are typically very thermally efficient and the fact that a portion of the CO_2 emissions from a non-affected CHP unit would have occurred anyway from an industrial boiler used to meet the thermal load in the absence of the CHP unit. In contrast, the CHP unit also provides the benefit of electricity generation while resulting in very low incremental CO_2 emissions beyond what would have been emitted by an industrial boiler. As a result, the accounting method does not presume that emission reductions occur outside the electric power sector, but instead only accounts for the CO_2 emissions related to the electrical production from a CHP unit that is used to substitute for electrical generation from affected EGUs.

The EPA is proposing with respect to the rate-based model rule that WHP units are eligible to generate ERCs. With respect to the federal plan, the EPA requests comment on the incorporation of non-affected WHP units. WHP units that meet the eligibility criteria under section VIII.K.1 of the Clean Power Plan preamble may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat

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

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

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

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

from that process is then used to generate electricity.[67] There are also WHP units where the waste heat from the initial combustion process is used to generate additional power. Under both configurations, unless the WHP unit supplements waste heat with fossil fuel use, there is no additional fossil fuel used to generate this additional power. As a result, there are no incremental CO_2 emissions associated with that additional power generation. As a result, the incremental electric generation output from the WHP units could be considered non-emitting, for the purposes of meeting the EGs, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU.[68] The MWh of electrical output from a WHP unit that can be recognized may not exceed the MWh of industrial or other thermal load that is being met by the WHP unit, prior to the generation of electricity.[69] In addition, where fossil fuel is used to supplement waste heat in a WHP application, the EPA requests comment on what provisions to include in the final model rule to prorate the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity. The EPA also solicits comments on other potential accounting mechanisms for WHP. As noted above, the EPA requests comment incorporating WHP as an ERC generating resource for the federal plan.

D. ERC Tracking and Compliance Operations

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

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

1. Designated Representatives and Alternate Designated Representatives

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

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

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

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

In addition to the flexibility provided by allowing an alternate to act for the designated representative (*e.g.,* in circumstances where the designated representative might be unavailable), additional flexibility would be provided by allowing the designated representative and alternate to delegate authority to make electronic submissions on his or her behalf. The designated representative and alternate could designate agents to submit

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

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

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

electronically certain specified documents. The previously-described requirements for designated representatives and alternates would provide regulated entities with flexibility in assigning responsibilities under the rate-based trading program, while ensuring accountability by owners and operators and simplifying the administration of the proposed rate-based trading program.

2. ERC Tracking and Compliance System

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

3. Tracking System Requirements

This federal plan and model rule's proposed tracking system and tracking systems that will be presumptively approvable for state plans fufill the criteria set forth in the final EGs. The EPA's tracking system includes provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are ''surrendered'' by the owner or operator of an affected EGU and ''retired'' or ''cancelled'' by the Administrator or administering state regulatory body), to ensure they are used only once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[70] and an accompanying tracking system infrastructure design. Each issued ERC will have a unique identifier (*i.e.,* serial number) and the tracking system will provide traceability of issued ERCs back to the program or project for which they were issued.

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

4. Compliance and General Accounts

This section describes two types of ATCS accounts: Compliance accounts, which would be established by the Administrator for each affected EGU upon receipt of the certificate of representation for the source; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any ERCs used by the affected EGU for compliance with the emissions limitations would have to be held until retired for compliance.

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

5. Compliance Demonstration

The EPA proposes that affected EGUs subject to this federal plan are required to meet compliance obligations by November 1 of the year following the end of the compliance period. For an affected EGU to meet its compliance obligations its average stack emission rate over the compliance period must be at or below its applicable rate standard, or the affected EGU must use ERCs to adjust its average stack emission rate to be at or below its applicable rate standard. An EGU's average emission rate over the compliance period will be calculated based on submitted data to ATCS. The compliance period average would be calculated by taking the measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU and dividing it by the total net energy output over the compliance period for that affected EGU in units of MWh.[71] This averaged emission rate will be compared to the emissions standards that the affected EGU is subject to during the corresponding compliance period. Accordingly, and if necessary, the appropriate number of ERCs will be retired from the affected EGU's compliance account to adjust the emission rate of the affected EGU to be equal to the emission standard. The discussion of using ERCs for compliance is found in section IV.D.10 of this preamble.

6. Recordation of ERC Generation and ERC Issuance

The EPA proposes to issue ERCs for ERC generating entities once per year. Thus, in a 3-year compliance period, for instance, there would be three points at which the agency issues ERCs. After

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

[71] Note that affected EGUs will submit these values to the EPA and the values will go through a transparent review process.

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

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

b. *Issuance of ERCs for Measures Used to Adjust an Emission Rate.* In the final EGs, the EPA has specified requirements for an ERC issuance process for the quantification and verification of measures used to adjust an emission rate that provide the necessary rigor and transparency while being efficient and streamlined. This is the intent of the federal plan as well, where there is a particular concern with implementing a streamlined and efficient federal process for ERC issuance across federal plan states. As required in the final EGs, we are proposing a two-step application process to the federal plan tracking systems for ERCs that allows for project approval to take place prior to the performance period, and makes the issuance of ERCs as quick and efficient as possible after generation has been quantified and verified, while still assuring a rigorous approval process. For the first step in the ERC issuance application process, the EPA proposes that RE and nuclear generation providers submit to the EPA or its designated agent an eligibility application for EPA approval, demonstrating that the project is eligible for the issuance of credits, including an EM&V plan that meets EPA requirements. The EPA requests comment on all aspects of the proposed ERC issuance process. The EPA also requests comment on how an ERC issuance process would apply to emission reduction measures for which we are requesting comment regarding their eligibility for ERC issuance under the federal plan, including types of RE not covered by the federal plan, demand-side EE, CHP, WHP, biomass, and any other measure that could be considered eligible under the final guidelines.

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

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

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

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

(4) There are special conditions if the provider is located in a state with a mass-based plan. For eligible RE capacity, the provider can only be credited in a rate-based state or rate-based multi-state system if the provider can demonstrate that the generation was produced to meet electricity load in a state with a rate-based plan. The EPA is proposing that an RE provider can make this demonstration by providing documentation of a power purchase agreement or delivery contract from the rate-based state and show that the measure was treated as a generation resource used to serve regional load that included the rate-based state. For incremental nuclear capacity, no provider in a state with a mass-based plan can be eligible for ERC issuance in a rate-based state. This requirement and the justification for its inclusion is further discussed in section III.A of this preamble on Interstate Effects and also discussed in the Interstate Effects section of the final EGs (see sections VIII.K.1 and VIII.L). The EPA is proposing that there would be no other geographic limitation on the location of the providers of RE and incremental nuclear generation submitted for ERC issuance under the rate-based federal plan approach.

(5) This application must include an independent third-party verifier's review and approval of the eligibility requirements, as is reflected in EM&V requirements for the final guidelines, and specified as part of the proposed federal plan EM&V requirements in section IV.D.8 of this preamble.

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

The EPA is proposing that ERCs would be tracked in the ATCS. Additionally, the EPA is proposing that the agency would establish a complementary tracking system for the ERC issuance process. It would provide for transparent access to RE project and program eligibility applications and regulatory approvals as well as information on the activities of accredited third party verifiers (third party verifiers are further discussed in section IV.D.7 of this preamble), as well for the public to be able to generate reports based on this information.

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

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

may designate an agent to coordinate the project application process and assist with review of applications.

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

The following are proposed required components of the M&V Report:

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

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

(3) Documentation that the MWh resulted from RE or incremental nuclear capacity eligible for crediting under the federal plan requirements and in accordance with final EGs. This documentation should note if the MWh are from an RE project located in a state with a mass-based plan, and show if the generation is approved to be eligible for ERC issuance under the federal plan. See above geographic eligibility discussion and section III.A of this preamble for specifics on the required demonstration for this type of RE generation. As discussed in that section, this option is proposed to not be available to incremental nuclear capacity located in a state with a mass-based plan.

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

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

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

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

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

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

The EPA proposes the following framework to implement the CEIP in the rate-based federal plan. First, the EPA proposes to implement a mechanism for issuing early action ERCs for eligible RE projects that commence construction and eligeible EE projects that commence implementation after September 6, 2018 and that generate zero-emitting MWh or reduce end-use energy demand during 2020 and/or 2021. These projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan. The EPA proposes to design this mechanism in a manner that would have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods. The EPA requests comment on the structure of this mechanism, which could include adjusting the stringency of the emission standards during the compliance periods to account for the issuance of early action ERCs for MWh

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

generated or avoided in 2020 and/or 2021. For example, during the interim performance period, a number of ERCs could be retired in an amount equivalent to the number of early action ERCs that were awarded for MWh generated or avoided in 2020 and/or 2021. As another option, the EPA, or a state under the model trading rule, could adjust their targets to achieve the same stringency, taking into account the additional borrowed ERCs. The EPA requests comments on all potential methods to adjust state targets, including modeling-based approaches, and on what information the state must present to demonstrate that the new targets preserve the needed stringency. More generally, the EPA requests comments on these ideas, as well as on alternatives for maintaining the stringency of a rate-based plan implementing the CEIP so as to have no impact on the aggregate emission performance of sources required to meet rate-based emission standards during the compliance periods.

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

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

7. Independent Verifiers

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

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

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

In addition, verifiers must have sufficient knowledge of the rate-based emission trading program rules, technical expertise, and knowledge of auditing, accounting, and information management practices, in order to perform verifcation services related to the Clean Power Plan. Accredited verifiers must be independent. Accredited verifiers may not provide verification services for any eligible resource for which they have a financial, management, or other interest.[75] Such relationships constitute a conflict of interest (COI). COI situations may also arise as a result of personal relationships among individuals representing an ERC provider and an accredited verifier. A verification report would not be

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

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

accepted as part of an eligibility application or M&V report where the accredited verification body or any individual verifier has a COI. Accredited verification bodies must have management protocols in place to identify and remedy any COI prior to provision of verification services. The proposed federal plan and model rule provide that failure of an accredited verifier to identify and adequately address any COI prior to provision of verification services is grounds for revocation of accreditation. The EPA would perform periodic reviews of accredited verifiers, to ensure that verifiers are maintaining necessary technical and professional qualifications and are meeting program requirements for provision of verification services. The EPA may recognize, in part, accreditation by an outside organization where such outside accreditation demonstrates that federal plan requirements are met.[76] The EPA requests comment on the proposed necessary requirements for an independent verifier to perform verification services in connection with the federal plan, including those requirements specifically detailed in this section of the preamble and the related language in the proposed model rule, and including whether there are any requirements that are not included in this proposal that should be included in the final rule. We further request comment on the level of detail that we should include in the final model rule regarding all requirements for indepenent verifiers, and all aspects of verification.

8. Evaluation, Measurement, and Verification Plans, Monitoring and Verification Reports, and Verification Reports

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

Only a subset of the potentially creditable ERC resources discussed in this section are actually being proposed as part of the federal plan. The remainder, and their associated requirements, are provided as part of the proposed model trading rule. Thus, all provisions of this subsection relating to such resources are presented only for the purpose of comment in the context of the federal plan, but are actually proposed for inclusion in the model trading rule. The ERC resources proposed in the federal plan must meet the following criteria: (1) They are in the following categories of measures: On-shore wind, solar, geothermal power, hydropower, or new nuclear units and capacity uprates at existing nuclear units; and (2) they can provide quantified generation data from a revenue quality meter. The language pertaining to all other measures (*e.g.,* demand-side EE) is proposed only for the model rule. While they are currently being proposed as part of the model rule and not the federal plan, the EPA requests comment on the inclusion of other RE measures, demand-side EE measures, and any other measures that may be eligible under the final guidelines as eligible measures under the federal plan. For stakeholders that are submitting comments on the inclusion of such additional measures, the EPA requests comment on how the EPA could implement across applicable jurisdictions a rigorous, straightforward, and widely demonstrated set of EM&V methods, procedures, and approaches that could be implemented in the time frame allowed by the federal plan and that also meet the requirements outlined in the final guidelines. To the extent they are proposed for inclusion in the model trading rule, we also invite comment on these requirements in the context of state implementation as part of a state plan. Thus, commenters on this aspect of the proposal should consider whether and how these provisions could be implemented at the state level. Comments that suggest an approach not authorized by the EGs will likely be considered outside the scope of this proposed rule.

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

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

a. *Overall Approach and Measure-Specific Requirements.* The proposed Clean Power Plan stated that the EPA would establish EM&V requirements and procedures to help states, sources, and resource providers quantify and verify MWh savings and generation resulting from zero-emitting RE and demand-side EE efforts. This action proposes those requirements that the EPA committed to establish. The Clean Power Plan proposal and associated ''State Plans Considerations'' TSD[80] suggested that such EM&V requirements would leverage existing industry practices, protocols, and tracking mechanisms currently utilized by the majority of states implementing RE and demand-side EE. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining, and enhancing their evaluation and quality assurance approaches for over 30 years, particularly with regard to the quantification and verification of energy savings resulting from utility-administered EE programs. The EPA also observed that the majority of RE generation is typically quantified and verified using readily available, reliable, and transparent methods such as direct metering of MWh. The EPA is proposing EM&V methods, procedures, and approaches, described herein, that are intended to be consistent with and leverage prevailing industry best-practices.

In addition, the EPA's proposed EM&V methods, procedures, and

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

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

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

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

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

approaches reflect several overarching objectives and principles offered by states, private organizations, and the public during the comment period of the Clean Power Plan EGs. One of these is the importance of balancing the accuracy and reliability of results with the associated costs of EM&V. Another objective for the EPA's proposed EM&V is to avoid excessive interference with existing practices that are already robust, transparent and effective.

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

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

Each M&V report submitted in support of the issuance of ERCs to a specific eligible resource must include specific criteria described here and in the proposed model rule. For the first M&V report submitted, a key component is documentation that the electricity-generating resources or electricity-saving measures were installed or implemented consistent with the description in the approved eligibility application. Each following M&V report must then identify the time period covered by the M&V report, describe how the methods specified in the EM&V plan were applied during the reporting period, and document the quantity (in MWh) of energy generation and/or electricity savings quantified and verified for the period covered by the M&V report. Any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report must also be included in the M&V report, along with the date on which the change occurred, and information sufficient to demonstrate whether the eligible resource continued to meet all eligibility requirements during the period covered by the M&V report. Any change should also be specified in the report. The EPA requests broad comment on each of these criteria, as described here and in the proposed model rule. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided and whether more or less detail (and what detail) should be included in the final model rule, and whether the criteria should differ for each eligible resource.

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

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

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

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

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

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

An additional consideration regarding distributed RE units that directly serve on-site end-use electricity loads is that avoided transmission and distribution (T&D) system losses can be quantified, as is commonly practiced with demand-side EE. If such T&D losses are quantified, the requirements for demand-side EE would be applicable.

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

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

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

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

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

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

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

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

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

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

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

The EPA requests comment on all metering, measurement, verification, and other requirements included in this subsection with respect to CHP, including the appropriateness of their use for CHP (including with respect to the size of the CHP resource). We request comment on whether a CHP unit should be subject to the same EM&V requirements as RE resources, and we request comment on any additional EM&V requirements to which CHP units should be subject. Specifically, we request comment on specifying in the final model rule that if a CHP unit has an electric generating capacity greater than 25 MW, its EM&V plan must specify that it will meet the requirements that apply to an affected EGU under 40 CFR 62.16540. We also request comment on specifying in the final model rule that if a CHP unit has an electric generating capacity less than or equal to 25 MW, the EM&V plan must specify that it will meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75. We request comment on any alternatives to these measurement methodologies that should be specified in the final model rule. We request comment on any other requirements that should be included in the final model rule regarding EM&V of CHP.

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

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

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

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

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

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

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

(1) Common Practice Baseline

Based on public input and assessments of industry best-practice protocols and procedures, the EPA is proposing that it is presumptively approvable to quantify EE savings as the difference between actual metered electricity usage after an EE program, project, or measure is implemented, and a ''common practice baseline'' (CPB). A

[81] When a CHP unit uses biomass fuel, it must report both total CO_2 emissions and biogenic CO_2 emissions. Proposed requirements for reporting biogenic CO_2 emissions are discussed below in the subsection titled Biomass *EM&V requirements.*

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

CPB is the equipment that would most frequently be installed at the time an existing piece of equipment fails or is replaced at the end of its effective useful life—or that a typical consumer or building owner would have continued using for the remainder of the equipment's effective useful life—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. It defines what would commonly have happened in the absence of the EE program, project, or measure.

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

(2) Methods Used To Quantify Savings From Energy Efficiency Programs and Projects

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

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

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

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

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

(3) Quantifying Savings

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

- How major changes in independent variable conditions (weather, occupancy, production rates, etc.) that affect energy consumption and savings estimates will be accounted for. The EPA is proposing that the effects of these changes must be calculated using industry best-practices such as real-time conditions or normalized conditions that are reasonably expected to occur throughout the lifetime of the EE project or measure.
- How the initial installation of EE will be verified for EE program categories that involve the installation of identifiable measures (*e.g.,* most utility consumer-funded EE programs and project-based EE are evaluated site-by-site). The EPA is proposing that verification is required within the first year of program implementation and that all verification activities must be performed using industry best-practice techniques (*e.g.,* phone or mail surveys, document review, site inspections, spot or short-term metering). For projects implemented as part of a larger program, the EPA is proposing that verification can be performed using a sample of projects to represent the full program population.
- How avoided T&D system losses [83] will be quantified and applied to EE savings determined at the customer facility or premises. The EPA is proposing that demand-side EE programs (other than T&D efficiency measures such as *conservation voltage regulation or reduction* (CVR) and volt/VAR optimization [84]) may adjust

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

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

reported savings by using a T&D adder. If such an adder is applied, the presumptively approvable approach is to use the smaller of 6 percent or the calculated statewide annual average T&D loss rate (expressed as a percentage) calculated using the most recent data published by the U.S. EIA State Electricity Profile.[85]

- How the duration of EE program or project electricity savings will be determined. This must be determined using industry best-practice protocols and procedures involving annual verification assessments, industry-standard persistence studies, deemed estimates of effective useful life (EUL), or a combination of all three.
- How the accuracy and reliability of quantifying MWh savings values will be assessed, and the rigor[86] of the methods used to control the types of bias or error inherent to the applied EM&V methods. Sampling of populations is appropriate, provided that the quantified MWh derived from sampling have at least 90 percent confidence intervals whose end points are no more than +/−10 percent of the estimate.
- How double counting will be avoided through the use of tracking and accounting procedures to ensure that the same MWh of electricity savings is not claimed more than one time (for example, two EGUs claiming savings from the same lighting retrofit). The types of double counting that may arise are discussed in the EPA's draft EM&V guidance.

(4) Use of Energy Efficiency EM&V Protocols

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

(5) Eligible Demand-Side Energy Efficiency (DS–EE) Programs and Projects

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

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

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

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

We request broad comment on each EE EM&V criterion described herein and in the proposed rule text, for each type of EE activity, project, program, or measure. Specifically, we seek comment on the substantive content of the criteria, and we seek comment on the level of detail provided regarding these criteria and whether more or less detail (and what detail) should be included in the final model rule. In addition, we seek comment on whether some of the EE EM&V criteria (and if so, which criteria) included in the draft guidance document released simultaneously with this proposed rulemaking should instead be included in the final model rule, instead of in guidance. Similarly, we seek comment on whether some of the EE EM&V criteria (and if so, which criteria) included in the proposed model rule should instead be addressed in the final EM&V guidance. More generally, we seek comment on what EE criteria the EPA should described in guidance versus what criteria the EPA should specify in the final model rule, whether or not those criteria are already included in the draft guidance or proposed model rule.

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

We request broad comment on whether, when, and how common practice baselines should and should not be used in calculating electricity savings from EE activities, projects, programs, and measures, including comment on which common practice baselines should be used in which circumstances. We also request comment on whether some alternative metric should be used in lieu of the common practice baseline and, if so, what that metric should be.

We request broad comment on the appropriateness of quantifying electricity savings by applying one or more of the following methods and comment on all aspects of each method: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings. We take further comment on circumstances in which it is appropriate (or inappropriate) to use each of these methods, including when it is appropriate to use RCT and quasi-experimental methods, and the circumstances in which they can be encouraged and applied in practice (*e.g.,* when a suitable control or comparison group can be identified and applied in a cost-effective manner). In addition, we request comment on whether the general suitability and applicaton of quantification methods, such as RCT,

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

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

quasi-experimental techniques or other comparison group approaches when they are available at reasonable cost for purposes of quantifying MWh savings for particular EE programs, projects, or measures.

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

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

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

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

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

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

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

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

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

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

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

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

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

9. ERC Transfers and Trading

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

Non-EGU ERC generating sources are required to submit generation data annually (see section IV.C.3 of this preamble for a comprehensive discussion of non-EGU ERC generating sources). The data must follow the EM&V procedures delineated in section IV.D.8 of this preamble. Because of the required rigor of the EM&V process, the EPA provides a time frame of January 1 to June 1 of the year that follows the data's inception to complete all EM&V processes (*e.g,* 2024 RE data must go through the EM&V process and be submitted to the EPA no later than June 1, 2025). After receiving all emission and generation data from ERC generating sources and affected EGUs, the EPA will issue ERCs through a NODA as described in section IV.D.6 of this preamble. The EPA is proposing to issue ERCs annually. ERCs are acquired and traded throughout the compliance period. An affected EGU is responsible to hold sufficient ERCs that qualify for Clean Power Plan compliance in its ATCS compliance account by November 1 at midnight of the year following the conclusion of the compliance period.[88]

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

10. Compliance With Emissions Standards

Once the compliance period has ended, affected EGUs would have a window of opportunity to evaluate their reported emissions and obtain any ERCs that they might need to cover their emissions during the compliance period. The agency proposes to require sources to demonstrate compliance, *i.e.,* ERC true-up, on November 1 of the year after the last year in the compliance period. For example, if the first compliance period comprises the three years 2022, 2023, and 2024, then the ERC transfer deadline[89] for that first compliance period (after which point the EPA would evaluate compliance) would be on November 1, 2025. The agency also requests comment on an earlier ERC transfer deadline, such as June 1 or March 1, of the year after the last year in the compliance period. Each ERC issued in the proposed rate-based trading program would, if applied, be averaged into the compliance rate as one MWh of energy with zero CO_2 emissions deemed associated with it for the compliance period that includes the year for which the ERC was issued or be averaged into a later compliance period. Consequently, each affected EGU would need, as of the ERC transfer deadline, to have in its compliance account enough ERCs usable for its compliance obligations for the compliance period. The authorized account representative could identify specific ERCs to be applied, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. The ERCs that are used to meet compliance obligations are moved from the compliance account to the EPA's retirement account. ERCs that are deducted for compliance will remain in the system in an EPA account, which ensures they will not be used again.

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

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

This equation can be rearranged to:

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

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

[88] This true-up process is further described in section IV.D.10 of this preamble.

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

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

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

11. Other ERC Tracking and Compliance Operations Provisions

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

12. Banking of ERCs

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

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

13. Emissions Monitoring and Reporting

The EPA would require that emission and generation data be reported to the EPA quarterly starting on April 30, 2022, and continuing every 3 months thereafter (*i.e.,* the 30th of April, July, October, and January). The EPA proposes that affected EGUs subject to the rate-based federal plan trading program would monitor and report CO_2 emissions in accordance with 40 CFR part 75. The EPA is proposing to require affected EGUs in all states covered by the rate-based federal plan trading program to monitor and report CO_2 emissions by and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many affected EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 (approximately 10 of these affected EGUs are coal fired with the remainder being gas and oil fired that will qualify for an excepted monitoring methodology) affected EGUs, that would not otherwise be subject to the ARP, will have to purchase and install additional continuous emissions monitoring system (CEMS) and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program. Several of the affected EGUs not otherwise subject to the ARP are subject to the MATS program and therefore will have already installed stack flow rate and/or CO_2 monitors in order to comply with the MATS rule which are also necessary to comply with this rule. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. The Regional Greenhouse Gas Initiative (RGGI), ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs. The majority of the affected EGUs covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

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

E. Federal Plan and State Plan Interactions

1. Interstate Trading

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

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

2. Treatment of States Entering or Exiting the Trading Program

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

V. Mass-Based Implementation Approach

A. Trading Program Overview

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

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

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

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

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

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

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

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

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

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

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

B. Statewide Mass-Based Emissions Goals

In the Clean Power Plan EGs the EPA established statewide mass-based emission goals (''mass goals'') for all states that are equivalent to the rate-based goals. As discussed in section V.C of this preamble, below, the EPA proposes to implement the mass-based trading program with multi-year compliance periods that are consistent with the compliance timing provisions in the Clean Power Plan EGs, *i.e.,* two 3-year compliance periods followed by a 2-year compliance period in the Interim Period, and successive 2-year periods in the Final Period. In the Clean Power Plan EGs, the EPA established mass goals for all states for this pattern of compliance periods. The EPA proposes to use those mass goals promulgated in the Clean Power Plan EGs as the mass limits (*i.e.,* emissions budgets) for any state covered by the mass-based trading program (or, if implementing interstate trading, then the EPA would use the sum of a covered group of states' mass goals as the aggregate mass limit). The EPA is not opening for comment the determinations, made in the Clean Power Plan EGs, of each state's mass goals. The mass goals are provided for convenience in Table 8 of this preamble.

TABLE 8—STATEWIDE MASS-BASED EMISSION GOALS (''MASS GOALS'')

[Short tons]

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona *	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846

TABLE 8—STATEWIDE MASS-BASED EMISSION GOALS ("MASS GOALS")—Continued

[Short tons]

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico *	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah *	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

* Excludes EGUs located in Indian country within the state.

C. Compliance Timing and Allowance Banking

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

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

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

The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, ''[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month.'' *See e.g.,* June 13, 1989 Guidance on Limiting Potential to Emit in New Source Permitting and January 25, 1995 Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits. The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

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

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

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

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

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

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

The EPA proposes to evaluate compliance (*i.e.,* allowance true-up) at the facility level, not at the individual affected-EGU level, in the mass-based trading program. Facility-level compliance may ease implementation compared to unit-level compliance; each facility has a single compliance account in which to hold allowances to cover emissions from all its affected EGUs rather than having individual unit-level compliance accounts. Fewer accounts may make it easier for the designated representatives to manage their allowances. The EPA has adopted facility-level compliance in previous emissions budget-trading programs including the ARP, *see* 70 FR 25162, at 25296–98 (May 12, 2005); the CAIR FIP, *see* 71 FR 25328, at 25365 (April 28, 2006); and the CSAPR, *see* 75 FR 45210, at 45323 (August 2, 2010). The EPA

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

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

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

would continue to track unit-level emissions—while evaluating compliance at the facility level—allowing us to track increases and decreases of pollutants at individual EGUs.

D. Initial Distribution of Allowances

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

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

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

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

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

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

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

The following sections discuss and request comment on the EPA's proposed approach to allocate CO_2 allowances to affected EGUs based on shares of historical generation, the proposed timing of allowance recordation, three proposed allowance set-asides, allocations to units that change status, and the proposed approach for states to replace federal plan allocation provisions with their own allowance-distribution approaches. In addition, we

[93] As detailed in section V.E in this preamble, we propose that a state that chooses to determine its own allowance-distribution approach under the proposed federal plan must address leakage through its allocation strategy (such as the set-aside approaches in section V.D.3 of this preamble). We request comment on whether a state may make a justification regarding leakage as detailed in section V.E of this preamble.

request comment on alternative allowance distribution approaches—such as auctioning or allocations to load-serving entities—that the EPA or states might adopt. The EPA requests comment on all of these aspects of allowance distribution.

1. Proposed Allocation Approach and Alternatives

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

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

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

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

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

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

(1) For each unit in the list of likely affected EGUs in each state, identify annual net generation values for the historical period of 2010 through 2012 (reflecting affected-EGU-specific generation assumptions incorporated in the data adjustments, *e.g.,* assumed capacity factor for ''under construction'' units). For a year for which an affected EGU has no generation data (*e.g.,* a year before the year when a unit started operating), assign the affected EGU a value of zero.[95] (See step 2, below, for how zero values would be treated in the calculations.)

The EPA proposes to use a 3-year historical period (*i.e.,* 2010 through 2012) to reflect unit-level operations over time. In the Clean Power Plan EGs, the EPA identified a reasonable basis for using aggregate data at the regional level largely based on the most recent data year (in that case, 2012) to inform the establishment of category-wide EGs (as opposed to individual, unit-specific parameters). As a distinct matter, in this context the EPA is considering data at the unit level to inform unit-specific initial allowance allocations; notwithstanding that these allowance allocations do not impose any unit-level compliance requirements in and of themselves, the EPA finds it reasonable to consider a multi-year data period to inform unit-level initial allocations in order to consider a broader range of unit-specific operations over time.

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

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

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

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

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

- The agency believes that the proposed historical-generation-based approach maximizes transparency and clarity of allowance allocations. The EPA has placed in the docket the historical generation data and the calculations used to determine the proposed affected-EGU-level allocations. The agency also placed the proposed affected-EGU-level allocations, resulting from these calculations, into the docket. These calculations can be relatively easily replicated.
- To calculate allocations, the EPA proposes to use historical affected-EGU-level net generation data compiled using a methodology similar to the Emissions & Generation Resource Integrated Database methodology. The proposed calculation approach is described further below and in the Allowance Allocation Proposed Rule TSD in the docket. The historical-data methodology is described in the CO_2 Emission Performance Rate and Goal Computation TSD for Clean Power Plan Final Rule. The majority of the generation-unit-level data in this approach are from reports that emissions sources submit to the EPA under 40 CFR part 75 and to the EIA on forms EIA–860 and EIA–923. The EPA believes these are the best data available to the agency at the time of this proposed rule for calculating affected-EGU-level allocations.
- Allocating based on historical data (as opposed to data not yet reported)

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

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

allows for the distribution of allowances prior to the start of the program, which can facilitate compliance planning.

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

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

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

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

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

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

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

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

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

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

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

Allocation to LSEs can help mitigate bill impacts on electricity consumers when applied in concert with certain additional design features. In particular, if LSEs commit and/or are required to pass through to ratepayers the value from their selling of the allocated allowances, this approach can mitigate the impact of electricity bill increases on consumers that might otherwise result from application of the federal plan. As described in the Allowance Allocation TSD, this type of approach can also help to avoid or mitigate the potential for windfall profits for affected EGUs. The EPA could apply this approach by conditioning the receipt of allowances by LSEs on the pass through to consumers of any allowance value if necessary.

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

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

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

2. Timing of Allowance Recordation

The proposed historical-data-based allocation approach—which the EPA proposes to use to allocate all of the allowances in each state except for the set-aside allowances—is a one-time determination that is not updated. The allocations resulting from this approach would be determined prior to the start of the program. The EPA proposes to record the historical-data-based allowances for each compliance period in source accounts prior to the start of each compliance period, and to record allowances for one compliance period at a time. Recording allowances prior to the start of a compliance period provides certainty to affected EGUs of their allocations in advance of when the allowances are needed for compliance and can facilitate long-term planning.

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

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

Recording allowances for one compliance period at a time provides flexibility for a state to replace the federal plan with its own plan in a timely way. As discussed in section V.F of this preamble, the EPA proposes to allow a state to replace the federal plan with its own approved state plan, for a compliance period for which allowances have not yet been recorded (the proposed schedule for allowance recordation is detailed below). The EPA also proposes that a state could choose to replace the federal plan allocations to its affected EGUs (and other entities) with its own allocations approach, for a compliance period for which allowances have not yet been recorded as detailed in section V.E of this preamble.

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

3. Allowance Set-Asides To Address Leakage to New Sources

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

The final EGs specify the concern of leakage, which is defined in section VII.D of the final EGs preamble as the potential of an alternative form of implementation of the BSER (*e.g.,* the rate-based and mass-based state goals) to create a larger incentive for affected EGUs to shift generation to new fossil fuel-fired EGUs relative to what would occur when the implementation of the BSER took the form of standards of performance incorporating the subcategory-specific emission performance rates representing the BSER. The final EGs specified that mass-based plan approaches must address leakage, because the form of the mass goals may ultimately impact the relative incentives to generate and emit at affected EGUs as opposed to shifting generation to new sources, with potential implications for whether the mass goal implements or is consistent with the BSER and overall emissions from the sector. These circumstances are much less likely to be present under a rate-based plan approach, where the form of the goal ensures sufficient incentive to affected existing EGUs to generate and thus avoid leakage, similar to the CO_2 emission performance rates. By requiring mass-based plan components that address leakage, the final EGs ensure that mass goals are equivalent to the CO_2 emission performance rates and are thus an equivalent expression of the BSER. Section VII.D of the final EGs details the requirement for addressing leakage and why it is needed, and section VIII.J of the final EGs specifies options for mass-based state plan components that address leakage. We are proposing, as part of the mass-based approach under the federal plan and model rule, to implement allowance allocation approaches to address leakage, specifically through establishing an output-based allocation set-aside and a set-aside that encourages the installation of RE.

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

Section VIII.J of the final EGs provides a discussion of how set-asides can effectively address leakage in a mass-based plan approach. That section of the final EGs also describes why the allowance allocation alternative for addressing leakage must be chosen for the federal plan instead of the option to regulate new non-affected fossil fuel-fired EGUs. This is because the EPA does not have authority to extend regulation of and federal enforceability to new fossil fuel-fired sources under CAA section 111(d), and therefore we cannot include new sources under a federal mass-based plan approach.

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

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

The EPA is aware of the successful use of set-asides and similar programs in other emissions trading programs. The following are examples of set-asides and similar programs used in other federal air quality rules.

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

As part of the ARP under Title IV of the 1990 CAA Amendments, Congress established a ''conservation and renewable energy reserve'' account. *See* CAA section 404(f), 42 U.S.C. 7651c(f). This is in essence a set-aside account of

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

[99] In designing a federal plan under CAA section 111(d), the EPA recognizes its authority as being, in some sense, the same as that available under CAA section 110(c), where the use of economic incentives is authorized. *See* CAA section 302(y), 42 U.S.C. 7602(y) (authorizing use of ''economic incentives'' in FIPs).

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

SO_2 allowances which the regulated utilities could earn by undertaking ''qualified energy conservation measures'' and ''qualified renewable energy'' projects. The size of the reserve was set at 300,000 allowances, and utilities could earn one SO_2 allowance for every 500 MWh of energy saved through demand-side EE savings or RE generation. In the first years of the program, utilities received bonus allowances equivalent to close to 3,000 tons of avoided SO_2 emissions, while achieving co-benefits from reductions in other pollutants, and, in the words of one industry representative, ''creating a culture change where utilities are looking for opportunities everywhere.''[101] The reserve program was nonetheless undersubscribed, and the EPA and other parties have learned from this case and made adjustments to similar programs to promote participation. This proposal seeks to minimize the administrative burden associated with participation in this rule's proposed set-asides.

In the NO_X SIP Call, the EPA encouraged states to consider including energy efficiency and renewables as a strategy in meeting their emission budgets through the use of set-asides. *See* 63 FR 57356, 57438 (October 27, 1998). A number of states created RE and demand-side EE set-asides in their SIPs in response, and later, for the implementation of CAIR. A ''roundtable'' meeting with 25 states in 2006 indicated that states that had established these programs were generally having success with them, and provided a forum for exchanges of ideas on how to handle a variety of implementation issues, such as over- and under-subscription, application issues, compliance and verification, the appropriate size of a set-aside account, how to garner public input on which projects are selected, and other issues.[102] In general, the EPA believes its experience and those of the states with these set-aside programs support the view that they are an effective means to spur clean energy projects, which in turn we believe can help to reduce the risk of leakage in this instance.[103]

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

a. Set-Asides for Output-Based Allocation

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

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

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

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

The EPA also requests comment on extending output-based allocation from this set-aside to affected SGUs. Output-based allocation for SGUs may increase generation subject to the mass limit, leading to reduced generation and emissions from new emitting sources. However, the EPA does not propose this approach because it is not as effective as output-based allocation to NGCC units.

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

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

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

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

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

The EPA also solicits comment on the timing of the output-based allocation set-aside's allocation procedure, which involves the relationship between the time at which eligible generation occurs and the vintage year(s) of the allowances allocated from this set-aside to recognize that generation. The EPA is proposing a lagged accounting procedure for this set-aside, where eligible generation that occurs during a given compliance period would receive allowances through this set-aside taken from vintage years in the subsequent compliance period. In keeping with this lagged accounting procedure, the EPA is proposing not to reserve any allowances of vintage years during the first compliance period (2022–2024) for allocation through this set-aside; eligible generation that occurs during the first compliance period would be recognized through this set-aside with allowances of vintage years from the second compliance period (2025–2027).

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

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

The EPA proposes to calculate an NGCC unit's capacity factor based on the previous compliance period's net generation and the net summer capacity of the unit. The EPA is proposing to require affected EGUs to report net generation to the agency.[106] The EPA proposes to use net summer capacity as reported to EIA. In the alternative, the EPA proposes to require that NGCC units report net summer capacity directly to the EPA by adding it as a required data field in the certificate of representation that a unit's owner or operator would submit to the agency (see section V.G of this preamble). The EPA notes that the EIA net summer capacity data is reported at the generator level; if we add this data point to the certificate of representation it would be reported at the affected-EGU level, which would facilitate calculation of capacity factors. The EPA also requests comment on whether the ''maximum load value,'' which is a parameter that EGUs report to the EPA in their monitoring plans, is a reasonable proxy for EGU-level net summer capacity for these calculations. The EPA also requests comment on an alternative approach of basing the capacity-factor calculation on nameplate capacity instead of net summer capacity, or other approaches to the calculation.

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

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

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

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

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

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

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

The set-asides resulting from this proposed approach are shown in Table 9 of this preamble. The set-asides in the table would apply to every compliance period except for the first compliance period for which there would be no output-based set-aside. Although the size of the set-aside would remain the same for each compliance period, as the mass goals decrease with each step in the Interim Period and to the Final Period, the set-asides would constitute an increasing share of a state's mass goal. The Allowance Allocation Proposed Rule TSD further details the proposed approach to determine the size of the set-aside. The EPA requests comment on a potential limit for the size of the set-aside in a compliance period based on a percentage of the state's total allowances for the compliance period.

TABLE 9—PROPOSED SIZE OF OUTPUT-BASED SET-ASIDE FOR THE SECOND COMPLIANCE PERIOD AND LATER

[Short tons]

State	Allowances in output-based set-aside
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671
Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167
Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

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

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

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

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

b. Set-Asides for Renewable Energy Projects

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

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

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

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

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

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

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

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

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

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

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

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

After each generation year, RE providers receiving allowances will have to provide an M&V report with the MWhs of RE generation actually produced, to assure that they have met the projected level of generation. These M&V reports need to document that the generation was by an approved project, and the report should be approved by a third party verifier. As discussed in section IV.D.8 of this preamble (EM&V section for the rate-based approach), these data should be readily available from existing metering. The EPA requests comment on the process for submitting M&V reports with actual generation.

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

The EPA is proposing that once allowances have been distributed to all approved providers, any remaining allowances in the set-aside, such as set-aside allowances designated for projects that no longer exist, will be redistributed to affected EGUs in the state in a pro rata fashion on the same distribution basis as their initial allocations were made. It is proposed that this will occur immediately after the distribution of set-aside allowances to eligible RE providers on December 1 of the year prior to the generation year in question. The EPA requests comment on this approach.

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

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

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

4. Provisions To Encourage Early Action

For purposes of the proposed mass-based federal plan, the EPA proposes to implement the Clean Energy Incentive Program (CEIP) on behalf of a state by issuing early action allowances for eligible actions located in or benefitting the state. Eligible projects must commence construction in the case of RE or commence operations in the case of low-income EE after September 6, 2018, and will receive incentives based on the zero-emitting MWh they generate, or the energy savings they achieve, during 2020 and/or 2021.[109] These early action allowances would be drawn from a third set-aside of allowances from the general distribution methodology. The EPA believes it is reasonable to establish the total amount of the early action set-aside in an amount equal to the pool of matching allowances. Thus, the EPA proposes that the total early action set-aside would be of an amount equal to the pool of matching allowances: No more than 300 million CO_2 allowances, depending on how many states are subject to a federal plan.

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

For the purposes of the mass-based federal plan, the EPA is proposing to award early action allowances to two types of eligible projects that are located in or benefit the state for which the EPA is implementing a federal plan:

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

Eligible RE projects must commence construction, and eligible EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. These projects will receive incentives for the MWh they generate or the end-use energy demand reductions they achieve during 2020 and/or 2021.

The EPA proposes the following framework to implement the CEIP in the mass-based federal plan. First, the EPA proposes to create a set-aside of early action allowances for all federal plan states, as described above. Second, the agency proposes to create an account of "matching" allowances for each state participating in the CEIP—regardless of whether a state is implementing a state plan or the agency is implementing a federal plan on its behalf. This distribution would reflect each state's pro rata share of a federal pool of additional allowances—based on the amount of the reductions from 2012 levels the affected EGUs in the state are required to achieve relative to those in the other participating states[111]—which would be limited to the equivalent of 300 million short tons of CO_2 emissions. Thus, states whose EGUs have greater reduction obligations will be eligible to secure a larger proportion of the federal allocation upon demonstration of quantified and verified MWh of RE generation or demand side-EE savings from eligible projects realized in 2020 and/or 2021. The EPA intends that a portion of these matching allowances would be reserved for eligible wind and solar projects, and a portion would be reserved for eligible EE projects implemented in low-income communities. The agency recognizes that there have been historical economic, logistical and information barriers to implementing EE programs in these communities, and therefore believes it is appropriate to reserve a portion of the federal pool to incentivize investment in these programs. The EPA requests comment on the size of reserve of matching allowances for eligible low-income EE programs as well as for eligible wind and solar projects. The EPA is proposing that unused allowances in either reserve would be redistributed among participating states. This redistribution could be executed according to the pro-rata method discussed above. Alternatively, unused matching EE or RE allowances could be swept back into a federal pool and distributed to project providers on a first-come, first served basis. The EPA requests comment on these ideas as well as alternative proposals regarding the method for redistributing matching allowances, as well as the appropriate timing for such a redistribution.

Following the effective date of a federal plan for a state, the agency will create an account of matching allowances for the state that reflects the pro rata share of the 300 million short ton CO_2 emissions-equivalent matching pool that the state is eligible to receive. Any matching allowances that remain undistributed after September 6, 2018[112] will be distributed to those states with approved state plans that include requirements for CEIP participation, as well as to those states on whose behalf the EPA is implementing a federal plan. These allowances will be distributed according to the pro rata method outlined above. Unused matching allowances that remain in the accounts of states participating in the CEIP on January 1, 2023, will be retired by the EPA. The EPA seeks comment on whether the number of matching allowances available to a state under the mass-based federal plan should be limited to a number equal to the number of early action allowances included in each federal plan state's early action set-aside.

Third, for any state subject to a federal plan, the EPA proposes to award early action allowances and matching allowances to eligible projects as

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

[110] The 2012 baseline is from the CO_2 Emission Performance Rate and Goal Computation TSD for the Clean Power Plan Final Rule. Where a state's relative share of the reductions from 2012 levels would yield a set-aside of less than zero, the EPA proposes to assign such a state a set-aside equal to one percent of the state's 2030 mass goal and adjust the remaining state set-asides accordingly.

[111] This is the same distribution method proposed above for the allocation of early action set-aside allowances to mass-based federal plan states.

[112] This may occur because not all states may elect to include requirements for CEIP participation in their state plans.

follows, based upon the quantified and verified MWh of generation or savings achieved by the projects in 2020 and/or 2021:

- For RE projects that generate metered MWh from any type of wind or solar resources: For every two MWh generated, the project will receive a number of allowances equivalent to one MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to one MWh from the EPA.
- For EE projects implemented in low-income communities: For every two MWh in end-use demand savings achieved, the project will receive a number of allowances equivalent to two MWh from the state early action allowance set-aside, and a number of matching allowances equivalent to two MWh from the EPA.

The EPA will address implementation details of the CEIP in a subsequent action. Allowances awarded by the EPA pursuant to the CEIP may be used for compliance by an affected EGU with its emission standards in any compliance period and are fully transferrable prior to such use. The EPA proposes to distribute any remaining early action set-aside allowances in a state—after distribution to all eligible projects in the state—to the affected EGUs in the state on a pro-rata basis in proportion to the initial allocations made to those EGUs under the mass-based federal plan.

As discussed in section V.E of this preamble, the EPA proposes to allow any state where a federal plan is being implemented to take responsibility for distributing allowances. This will allow a state to tailor its allowance-distribution approach to the characteristics and preferences of the state. The EPA proposes that a state that chooses to replace the federal plan allocations with a state-determined approach must include a CEIP set-aside, as authorized in section VIII.B.2 of the final EGs. The EPA intends that such a state would have the same flexibilities as a state implementing a full state plan with respect to implementation of the CEIP. That is, the state would not be required to implement a set-aside of the same size as proposed in Table 10 of this preamble, but rather could choose how many of its allowances to set-aside for the CEIP.

The EPA requests comment on all aspects of implementing the CEIP under a mass-based federal plan approach, including (1) The size of the early action allowance set-aside; (2) the approach for distributing the early action allowance set-aside among states; (3) the timing of distribution of set-aside and matching allowances; (4) the amount of allowances awarded per eligible MWh generated or avoided; (5) the criteria for eligible projects, including criteria for awards to EE projects implemented in low-income communities; (6) the mechanism for reviewing project submittals and issuing early action allowances; (7) EM&V requirements for eligible projects; and, (8) the number of early action and matching allowances that should be awarded for each ton of emissions reduced from eligible generation or low-income efficiency projects to ensure a robust response to the program. The EPA also seeks comment on how states, tribes and territories for whom goals have not yet been established in the final EGs may be able to participate in the CEIP in the future.

The EPA also requests comment on the proposed approach of requiring states to implement this program as a condition of a state choosing to determine its own allocation approach via a partial state plan or a delegation of the federal plan.

TABLE 10—PROPOSED CLEAN ENERGY INCENTIVE PROGRAM EARLY ACTION ALLOWANCE SET-ASIDE IN THE MASS-BASED FEDERAL PLAN

[Short tons]

State	Set-aside 2022 through 2024
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929
Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183
Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

5. Allocations to Units That Change Status

Units that retire. The EPA proposes that, if an affected EGU does not operate for 2 consecutive calendar years, the unit would continue to receive allocations for a limited number of years after it ceases operation, after which the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside for the state in which the retired unit is located.[113] Continuing allocations to non-operating units for a period of time reduces the incentive to keep a unit operating simply to avoid losing the allowance allocations for that unit (*e.g.,* a unit that would otherwise be retired due to age and inefficiency). On the other hand, non-operating units are no longer emitting and so do not need allowances. The EPA believes that the proposed approach of allocating allowances for a specified, but limited, period after a unit ceases operating is a reasonable middle ground approach. The proposed approach also allows the RE set-asides to grow over time.

The EPA proposes to record allowances for each year of a multi-year compliance period at once, 7 months prior to the start of each compliance period, as discussed above. The agency proposes that, if an affected EGU does not operate for 2 full calendar years, then starting with the next compliance

[113] This is similar to the approach taken in CSAPR of continuing allocations to retired units for four years and then allocating the allowances to a set-aside; in CSAPR the set-aside is for new units.

period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. As a result, the number of years of non-operation for which a retired unit would receive allocations would vary depending on when a unit retires. For example, if an affected EGU does not operate for the first two calendar years of a 3-year compliance period, then starting with the next compliance period the allowances that would otherwise have been allocated to that unit would be allocated to the RE set-aside—in other words the unit would receive allocations for 3 years of non-operation. As a further example, if an affected EGU does not operate for both calendar years of a 2-year compliance period, then starting with the compliance period after the next compliance period the allowances would be allocated to the RE set-aside—in other words the unit would receive allocations for 4 years of non-operation.

The agency requests comment on this approach for treatment of allocations to affected EGUs that retire, including on the number of years of non-operation for which a unit would continue to receive allocations. The EPA also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state's RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the retired units. The EPA also requests comment on treatment of allocations to units that are in long-term cold storage.

Units that are modified or reconstructed. Similar to the approach for an affected EGU that retires, the EPA proposes that, if a unit is modified or reconstructed such that it is no longer an affected EGU, then starting with the next compliance period for which allowances have not yet been recorded, the allowances that would otherwise have been allocated to the unit would be allocated to the RE set-aside. The EPA requests comment on this proposed approach, including on the number of years for which a unit would continue to receive allocations. The agency also requests comment on an alternative of distributing such allowances to the set-aside for output-based allocations, or to the remaining affected EGUs in the state in a pro-rata fashion (on the same distribution basis as the initial allocations were made), instead of allocating such allowances to the state's RE set-aside. The agency requests comment on a further alternative approach, which would be to continue allocations to the modified or reconstructed units.

E. State-Determined Allowance Distribution

The EPA proposes to allow any state to replace the EPA-determined federal plan allowance-distribution provisions in the mass-based trading program with state-developed allowance-distribution provisions. In this way, a state could choose how to distribute initial allowance allocations among its affected EGUs (and other entities).

The EPA believes that this option may offer significant appeal, because it will allow a state to tailor its allocation approach to the characteristics and preferences of the state. A state would be able to design its allocation approach to address its particular state priorities, whether they are protecting low-income consumers, supporting local industries, or other goals. The EPA anticipates that a state would have great flexibility in its allowance distribution approach and could take advantage of allocation options discussed in this proposal as well as other allocation options a state might prefer. States could auction allowances and rebate the revenue to consumers, or allocate all allowances to load-serving entities, while mandating that the value be passed through to vulnerable consumers. The EPA believes that the state-determined allocation approach offers significant advantages and solicits comment on how to ease its application by states. This is similar to the approach taken in CSAPR and CAIR where the EPA adopted rules allowing states to submit SIPs with provisions replacing the allowance-distribution provisions in the CSAPR or CAIR FIPs, respectively, while remaining in the trading programs under those FIPs (76 FR 48208; August 8, 2011, 71 FR 25328; April 28, 2006). In both CSAPR and CAIR, some states have chosen to determine their own allocations under the FIPs. This form of SIP that can replace the allowance-distribution provisions in CSAPR or CAIR is termed an ''abbreviated SIP revision.'' In this proposed mass-based trading federal plan, the EPA proposes that a state may choose to submit a ''state allowance-distribution methodology'' (analogous to an abbreviated SIP revision) to replace the federal plan allowance-distribution provisions with allowance-distribution provisions of its choosing.

The mechanism the agency envisions is in the nature of a partial state plan or (for any future changes in a state's allocation methodology) a partial state plan revision. (We request comment below on the advantages and disadvantages of allowing a state to handle allocations via a delegation of federal plan authority.) In general, under the proposed approach, the procedural requirements states and the agency must follow, including public notice requirements, for the submission and approval of state plans, would be required here.

The EPA intends to provide the states with substantial flexibility in choosing approaches to distribute their allowances in a state allowance-distribution methodology. The EPA proposes that a state may choose any approach, including auctions or other methods the EPA is not proposing here, provided the state's approach addresses leakage and also implements the Clean Energy Incentive Program. The EPA is also requesting comment on any other appropriate constraints to impose on state allowance-distribution methodologies.

The Clean Power Plan EGs require mass-based state plans to include a demonstration that they have addressed the risk of leakage, and the EGs provide several options for doing so (*see* sections VII.D and VIII.J of the final EGs). One of the options provided in the EGs is to address leakage through an allowance distribution approach that provides incentive to counteract leakage. In the mass-based trading federal plan, the EPA's proposed approach to allocate allowances would address leakage using two allowance set-asides, one for output based allocation and one for RE projects, as detailed in section V.D.3 of this preamble. The EPA believes that a state allowance-distribution methodology, which would replace the federal plan allocation provisions, must also address leakage. The EPA proposes that a state allowance-distribution methodology must address leakage by providing incentive to counteract leakage, *e.g.,* by including allowance set-asides like the output-based allocation and RE set-asides detailed in section V.D.3 of this preamble, or other allocation approaches designed to counteract leakage. The EPA requests comment on this proposed approach for addressing leakage in a state allowance-distribution methodology and on any other approaches for doing so. The EGs provide an additional option for state plans to address leakage, where a state would provide a demonstration that leakage will not occur (without implementing any of the strategies specified in the EGs) due to specified characteristics of the state (section VIII.J of the final EGs). In this federal plan proposal, the EPA requests comment on an alternative option where a state that chooses to submit a state allowance-distribution methodology could provide a demonstration that leakage will not occur (without implementing the allocation strategies specified here) due to specific characteristics of the state; the EPA proposes that such demonstration must meet the requirements in the final EGs, including support by credible analysis, for such a demonstration (*see* final EGs section VII.D). The EPA notes that a state's allowance-distribution methodology may also include other set-aside approaches that are not designed to counteract leakage.

The Clean Power Plan EGs established a Clean Energy Incentive Program (section VIII of the final EGs). The EPA proposes that a state allowance-distribution methodology, which would replace the federal plan allocation provisions, must also include a Clean Energy Incentive Program, as detailed in section V.D.4 of this preamble.

Under the proposed approach of providing for states to determine their allowance distribution approaches in the federal plan mass-based trading program, the affected EGUs in a state that submitted a state allowance-distribution methodology, which the EPA approved, would participate in the federal plan mass-based trading program, but with allowance distribution determined by the state instead of by the EPA.

The EPA proposes that a state must submit to the Administrator tables specifying the unit-level allowances in an electronic format specified by the Administrator and by the specified deadlines applicable to each compliance period (*see* Table 11 of this preamble for proposed submission deadlines).

The EPA proposes that a state may submit a state allocation methodology for any compliance period, including the first compliance period, which would comprise the years 2022, 2023, and 2024. The EPA proposes that a state submitting a state allowance-distribution methodology to modify the federal plan allowance-distribution provisions must do so for all years within a compliance period (*e.g.,* for all 3 years in a 3-year compliance period).

The EPA proposes that, if the state's allowance-distribution provisions meet certain requirements and the state allowance-distribution methodology does not change any other provisions in the proposed mass-based trading program, then the agency would likely approve the state allowance-distribution methodology. In the state allowance-distribution methodology, the state could distribute allowances to affected EGUs or other entities (such as RE facilities) or could auction some or all of the allowances. The agency proposes that for EPA approval, the state allowance-distribution methodology provisions would have to meet the following requirements. The provisions would have to address leakage as discussed above. The provisions would have to provide that, for each year for which the state allowance-distribution provisions would apply, the total amount of allowances distributed could not exceed the applicable mass goal for that state for that year. A state's methodology under this proposed approach could provide that the total amount of allowances distributed is less than the applicable mass goal.[114] The EPA proposes that a state's allowance-distribution provisions would replace the EPA's allocation provisions completely—a state would not have the option of implementing only a portion of its allocations (*e.g.,* only set-asides) and having the EPA implement the remainder of its allocations. Additionally, the EPA proposes that a state allowance-distribution methodology must provide for allowances to be issued in short tons.

The allocation (or auction) of allowances would be final and could not be subject to modification. Additionally, the state's provisions could not change any other provisions of the proposed mass-based trading program with regard to the allowances (*e.g.,* the deadlines for allocation recordation, or requirements for transfer or use of allowances) or any other aspect of such trading programs.

In order for a state allowance-distribution methodology's provisions to replace the EPA's allowance-distribution provisions for a given compliance period, a state would have to submit the state allowance-distribution methodology by a deadline that would provide the agency sufficient time to review and approve it, and to submit the allowance table meeting the specified electronic format by a deadline that would provide sufficient time to record the unit-by-unit allowances in source accounts. The EPA believes that about 12 months—starting from the date of receipt of a state allowance-distribution methodology—is sufficient to complete the agency's review and approval process, which would have to provide an opportunity for public comment on the approval (or disapproval) action. Thus, the EPA proposes the following deadlines, in Table 11 of this preamble, for submission to the agency of state allowance-distribution methodologies and unit-level allowances, and for the EPA's recordation of allowances, for each compliance period. The EPA would review and approve state allowance-distribution methodologies in the 12 months between the proposed deadline for states to submit their methodologies and the proposed deadline for states to submit unit-level allowance tables. The proposed deadline for submission of allowance tables is 3 months before the proposed deadline for the agency to record allowances in source accounts. The EPA proposes to record allowances in source accounts by the recordation deadlines.

TABLE 11—PROPOSED DEADLINES FOR SUBMISSION OF STATE ALLOWANCE-DISTRIBUTION METHODOLOGIES AND UNIT-LEVEL ALLOWANCES AND FOR RECORDATION

First compliance period for which allowances would be distributed	Deadline for submittal of state allowance-distribution methodologies	Deadline for submittal of unit-level allowance table	Deadline for the EPA to record allowances
2022, 2023, 2024	March 1, 2020	March 1, 2021	June 1, 2021.
2025, 2026, 2027	March 1, 2023	March 1, 2024	June 1, 2024.
2028, 2029	March 1, 2026	March 1, 2027	June 1, 2027.
2030, 2031 *	March 1, 2028 *	March 1, 2029.*	June 1, 2029 *

* This pattern of deadlines would hold for successive 2-year compliance periods.

[114] A state allowance-distribution methodology under this proposed approach, which is analogous to an abbreviated SIP revision, could provide that the total amount of allowances distributed is less than the applicable mass goal, pursuant to the reserved authority to states to set emission standards more stringent than federal standards under CAA section 116.

The proposed deadlines for submission of state allowance-distribution methodologies are later than the state plan submission deadlines promulgated in the Clean Power Plan EGs. The agency anticipates that it can complete the approval process relatively quickly for a state allowance-distribution methodology due to its narrow scope.

The agency proposes to record the EPA-determined federal plan allocations *only* in the absence of an approved state plan or approved state allowance-distribution methodology. The EPA proposes to record in source accounts allowances that are determined by any state as soon as feasible after approval of a state allowance-distribution methodology and submission of the unit-level allowance table, and not to wait until the allowance recordation deadline to do so.

In section V.D.2 of this preamble, the EPA proposes that the allowance recordation deadline be 7 months prior to the start of the compliance period (*i.e.,* June 1 of the prior year) and also requests comment on a recordation deadline 13 months prior to the start of the compliance period (*i.e.,* December 1 of the year, 2 years before the compliance period starts). If the EPA adopted the earlier recordation deadline on which it requests comment or any other deadline, then we would adjust the deadlines for submission of state allowance-distribution methodologies and submission of unit-level allowance tables accordingly.

The EPA proposes that a state may not replace EPA-determined allocations for a compliance period for which federal plan allocations have already been recorded, for the same reasons that the agency proposes that a state may not replace a mass-based trading federal plan with a state plan for a future compliance period for which allowances have already been recorded, as discussed below in section V.F of this preamble.

The agency requests comment on the proposed approach to allow states to determine allocations via state allowance-distribution methodologies and replace the federal plan allowance-distribution provisions. The EPA requests comment on the proposed schedule for submitting state allowance distribution methodologies to the agency, for submitting the resulting unit-level allowance tables to the agency, and for the agency to record allowances. The EPA requests comment on its proposed approach of not replacing EPA-determined allocations for a compliance period for which allowances have already been recorded. The agency also requests comment on an alternative approach where a state could notify the EPA of its intent to submit a state allowance-distribution methodology in advance, in which case the agency would hold off on recording EPA-determined allocations to allow more time for state-determined allowances to be recorded, similar to the alternative timing approach discussed in section V.F of this preamble.

The EPA is also requesting comment on an alternative approach to provide the opportunity for a state to determine its allowance-distribution provisions in the federal plan mass-based trading program. The alternative approach on which the agency requests comment is to provide for a partial delegation of the federal plan—limited to the allowance-distribution provisions—to a state that wishes to determine its allowance-distribution provisions. The EPA requests comment on the relative efficiency and ease of implementation of the two approaches (the state allowance-distribution methodology described above, or the partial delegation). The agency requests comment on whether the partial delegation approach would provide sufficient flexibility for a state to choose any method to distribute its allowances including approaches that the EPA is not proposing here. See further discussion of delegations in section VI of this preamble.

F. Treatment of States Entering or Exiting the Trading Program

If the EPA implements a mass-based trading program federal plan for any state, the agency will work with a state that wishes to replace the federal plan with an approved state plan to provide a smooth transition. The EPA proposes that a mass-based trading federal plan could only be replaced by a state plan for a future compliance period for which allowances have not yet been recorded. For example, if a 3-year compliance period comprises 2022, 2023, and 2024, the EPA would record allowances in source accounts for 2022, 2023, and 2024 prior to 2022. Once 2022, 2023, and 2024 allowances had been recorded, the first compliance period for which a state could replace the federal plan with its own plan would be for the period commencing in 2025. The EPA is proposing this stipulation for the timing of replacing a federal plan with a state plan due to the need to avoid disruption to sources already subject to the mass-based trading federal plan. Without this stipulation, a state might withdraw from the mass-based trading program in the middle of a compliance period even though allowances that authorize emissions throughout that entire compliance period would already be in circulation. In that circumstance, the EPA would then need to address whether and how to remove those allowances from circulation to prevent inflation of the allowable emissions at affected EGUs in the remaining states subject to the federal plans beyond the levels specified in the Clean Power Plan EGs. The EPA believes it is more reasonable to avoid this potential disruption by requiring that the replacement of a federal plan with a state plan be scheduled to coincide with the conclusion of the last compliance period for which allowances under the federal plan have already been recorded for that state. The EPA requests comment on other approaches to provide a smooth transition from federal plan implementation to implementation by state plans, and on its proposed approach of not replacing a federal plan for any compliance period for which allowances were already recorded.

The agency requests comment on an alternative of providing for a state to give notice to the EPA of its intent to submit a state plan to replace the federal plan (or a state allowance-distribution methodology to replace federal plan allocations), and for the agency to delay recording federal plan allocations for sources in that state until a later date than proposed. The EPA requests comment on whether this alternative would help smooth the transition from federal plan implementation to state plan implementation, and on the trade-off between recording allowances in a timely way and providing this increased timing flexibility.

G. Allowance Tracking, Compliance Operations, and Penalties

The EPA proposes that the mass-based trading program use an ATCS operated essentially the same way as the existing systems that are currently in use for CSAPR and the ARP under Title IV. Under the proposed mass-based trading program, the CO_2 program would be a separate trading program maintained in the EPA's existing data system. ATCS would be used to track the trading of CO_2 allowances held by covered affected EGUs in facility level compliance accounts, as well as such allowances held by other entities or individuals. Specifically, ATCS would track the allocation of all CO_2 allowances, holdings of CO_2 allowances in compliance accounts (*i.e.,* a facility level account for all affected EGUs at the facility) and general accounts (*i.e.,* accounts for other entities such as companies and brokers), deduction of CO_2 allowances for compliance purposes, and transfers of allowances between accounts. The primary role of ATCS is to provide an efficient, automated means for affected EGUs to comply, and for the EPA to determine whether affected EGUs are complying, with the emissions limitations and any other requirements of the mass-based trading program. ATCS would also provide data to the allowance market and the public, including a record of ownership of allowances, dates of allowance allocations, allowance transfers, buyer and seller information, serial numbers of allowances transferred, emissions, and compliance information. This information would be publicly available on the EPA's Web site and in annual progress reports.

1. Designated Representatives and Alternate Designated Representatives

The EPA proposes to establish procedures for certifying and authorizing the designated representative, and alternate designated representative, of the owners and operators of an affected EGU and for changing the designated representative and alternate designated representative. The proposed provisions describe the designated representative's and alternate designated representative's responsibilities and the process through which he or she could delegate to an agent the authority to make electronic submissions to the Administrator. These provisions are patterned after the provisions concerning designated representatives and alternates in prior EPA-administered trading programs.

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

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

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

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

2. Allowance Tracking and Compliance System

The proposed mass-based trading program rules include procedures and requirements for using and operating the ATCS (which is the electronic data system through which the Administrator would handle allowance allocation, holding, transfer, and deduction), and for determining compliance with the allowance-holding requirements in an efficient and transparent manner. Under the proposed rules, the ATCS would also provide the allowance markets with a record of ownership of allowances, dates of allowance transfers, buyer and seller information, and the serial numbers of allowances transferred. Consistent with the approach in prior EPA-administered trading programs, allowance price information would not be included in the ATCS. The EPA's experience is that private parties (*e.g.,* brokers) are in a better position to obtain and disseminate timely, accurate allowance price information than is the EPA. For example, because not all allowance transfers are immediately reported to the Administrator for recordation, the Administrator would not be able to ensure that any reported price information associated with the transfers would reflect current market prices.

3. Compliance and General Accounts

The proposed provisions addressing compliance and general accounts describe two types of ATCS accounts: Compliance accounts, one of which the Administrator would establish for each facility with an affected EGU upon receipt of the certificate of representation for the facility; and general accounts, which could be established by any entity upon receipt by the Administrator of an application for a general account. A compliance account would be the account in which any allowances used by an affected EGU for compliance with the emissions limitations would have to be held. The designated representative and alternate for the affected EGU would also be the authorized account representative and alternate for the compliance account. Using facility-level, rather than EGU-level accounts, would provide owners and operators more flexibility in managing their allowances for compliance, without jeopardizing the environmental goals of the mass-based trading program, because the facility-level approach would avoid situations where an EGU would hold insufficient allowances and would be in violation of allowance-holding requirements even though EGUs at the same facility had more than enough allowances to meet these requirements for the entire facility. Facility-level compliance would also be consistent with other EPA-administered mass-based trading programs.

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

4. Recordation of Allowance Allocations and Transfers

The EPA proposes to establish the following schedule and procedures for recordation of allowance allocations and transfers. By June 1, 2021, the Administrator would record allowance allocations for EGUs for 2022 through 2024. Then, by June 1 of the year prior to the beginning of each compliance period, the Administrator would record the allowance allocations for the proposed mass-based trading program for each year within that next compliance period, *e.g.,* for 2025, 2026, and 2027 by June 1, 2024. Recording these allowance allocations in advance of the first year for which they could be used for compliance would facilitate compliance planning by owners and operators and promote robust allowance markets, including futures markets for allowances.

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

5. Compliance With Emissions Limitations

The EPA proposes to include the following provisions regarding compliance with emission limitations. Under the proposed provisions, once the compliance period has ended (*e.g.,* at midnight on December 31, 2024 for the first compliance period), facilities with affected EGUs would have a window of opportunity following the compliance period to evaluate their reported emissions and obtain any allowances that they might need to cover their emissions during the compliance period. For example, the allowance transfer deadline for the first compliance period would be midnight on May 1, 2025 (the EPA is also requesting comment on earlier or later allowance transfer deadlines). Each allowance issued in the proposed mass-based trading program would authorize emission of one ton of CO_2 and so would be usable for compliance, for the compliance period that includes the year for which the allowance was allocated or a later compliance period. Consequently, each affected EGU would need, as of the allowance transfer deadline, to have in its facility compliance account, or to have a properly submitted transfer that would move into its compliance account, enough allowances usable for compliance to authorize its total emissions for the compliance period. The authorized account representative could identify specific allowances to be deducted, but, in the absence of such identification or in the case of a partial identification, the Administrator would deduct on a first-in, first-out basis. Deducting allowances may have tax and accounting implications, so having a default deduction method provides the representatives with certainty regarding which allowances will be deducted for compliance. Allowances that are deducted for compliance will remain in the system in an EPA account, which ensures they will not be used again. If a facility were to fail to hold sufficient allowances for compliance by all affected EGUs at the facility, then the owners and operators of the facility and each affected EGU at the facility would have to provide, for deduction by the Administrator, two allowances allocated for the compliance period in the next year for every allowance that the owners and operators failed to hold as required to cover emissions. This submittal of two times the allowances required for the prior period is an ongoing obligation until compliance is achieved, and there is an ongoing obligation to comply in the current period. In addition, these owners and operators would be subject to civil penalties for each violation in accordance with the CAA, with each ton of unauthorized emissions and each day of the compliance period involved constituting a violation of the CAA.

The EPA believes that it is important to include a requirement for an automatic deduction of allowances. The deduction of one allowance per allowance that the owners and operators failed to hold would offset this failure. The automatic deduction of another allowance per allowance that the owners and operators failed to hold that could not be avoided, regardless of any explanation provided by the owners and operators for their failure, would provide a strong incentive for compliance with the allowance-holding requirement by ensuring that non-compliance would be a significantly more expensive option than compliance. Such automatic deductions have been successfully used in prior programs including the CAIR, achieving compliance rates close to 100 percent.

6. Other Allowance Tracking and Compliance Operations Provisions

The proposed provisions regarding allowance tracking and compliance also provide that the Administrator could, at his or her discretion and on his or her own motion, correct any type of error that he or she finds in an account in the ATCS. In addition, the Administrator could review any submission under the mass-based trading program, make adjustments to the information in the submission, and deduct or transfer allowances based on such adjusted information. These provisions are a standard part of other trading programs administered by the EPA including the ARP and Cross State Air Pollution Rule (*see* 40 CFR 72.96, 73.37, 97.427, and 97.428).

H. Emissions Monitoring and Reporting Requirements

The EPA proposes that units subject to the mass-based federal plan trading program would monitor and report CO_2 mass emissions in accordance with 40 CFR part 75.

The EPA is proposing to require affected EGUs in all states covered by the mass-based federal plan trading program to monitor and report CO_2 emissions and output data by January 1, 2022. Quarterly reporting would be required, with each quarterly report due to the Administrator 30 days after the last day in the quarter. The reporting would be in accordance with 40 CFR 75.60. The use of 40 CFR part 75 certified monitoring methodologies would be required. Many EGUs that might be covered by the proposed federal plans will generally have no changes to their monitoring and reporting requirements and will continue to monitor and submit reports under 40 CFR part 75 as they have under existing programs. The EPA anticipates fewer than 50 affected EGUs that would not otherwise be subject to the ARP will have to purchase and install additional CEMS and data handling systems or upgrade existing equipment in order to meet the monitoring and reporting requirements of this program (the EPA anticipates approximately 10 coal fired units and approximately 40 gas and oil fired units will qualify for an excepted monitoring methodology). Several of the units not otherwise subject to the ARP are subject to the MATS program and, therefore, will have already installed stack flow rate and/or CO_2 monitors necessary to comply with this rule in order to comply with the MATS. The CEMS used to comply and report data for MATS will be used for this rule to generate and report CO_2 emissions data without having to install duplicative monitors. The same CO_2 and stack gas flow rate monitored data used in conjunction with mercury and other CEMS to calculate a toxic pollutant emission rate may be used to calculate a CO_2 mass or CO_2 emission rate for this program. RGGI, ARP, MATS and this rule all refer to CEMS installed and certified in accordance with 40 CFR part 75. RGGI and ARP currently require the reporting of CO_2 mass emissions on an hourly basis and cumulative totals at the end of each calendar quarter. The same monitors and data collected may be used for multiple purposes for RGGI, ARP, MATS and this rule. Relying on the same monitors that are certified and quality ensured in accordance with 40 CFR part 75 ensures cost efficient, consistent, and accurate data that may be used for different purposes for multiple regulatory programs.

The majority of the units covered by this rule are already affected by the Acid Rain and/or RGGI programs and will have minimal additional monitoring and reporting requirements.

The EPA also requests comment on requiring monitoring and reporting of CO_2 mass and net generation for the year before the initial compliance period begins, *i.e.,* to commence January 1, 2021. Only the monitoring and reporting would be required in 2021—compliance with the requirement to hold allowances would commence on the compliance period schedule that is detailed in section V.C of this preamble.

VI. Implementation of the Federal Plan and Delegation

Under section 111(d) of the CAA, the EPA adopts EGs that are then implemented when the EPA approves a state or tribal [115] plan or promulgates a federal plan that implements and enforces the EGs for affected EGUs in states or areas of Indian country [116] without an approved state or tribal plan. Congress has determined that the primary responsibility for air pollution prevention and control rests with state and local agencies, while also recognizing that federal leadership is essential for the development of cooperative federal, state, regional, and local programs to prevent and control air pollution. *See* CAA section 101(a)(3) and (4). Congress has also provided for Indian Tribes meeting specified eligibility criteria to implement the CAA within the exterior boundaries of their reservations or other areas within the tribe's jurisdiction. *See* CAA section 301(d)(1) and (2). Even in the event that it becomes necessary for the EPA to directly regulate affected EGUs under CAA section 111(d), states and eligible tribes may still seek a delegation of authority from the EPA to implement a federal plan, similar to the ability to take delegated authority under other CAA programs. The EPA encourages states and eligible tribes that do not submit approvable plans to request delegation of the federal plan if they wish to have primary responsibility for implementing the EGs. Approved and effective state or tribal plans or delegation of the federal plan is the EPA's preferred outcome in many circumstances where the EPA believes that state and local, or tribal, agencies have practical knowledge and enforcement resources critical to achieving the highest rate of compliance. Delegation of a standard or requirement generally means that obligations a source may have to the EPA under a federally promulgated standard become obligations to a state or tribe in the first instance (except for functions that the EPA retains for itself) upon delegation.[117] [118]

A. Delegation of the Federal Plan and Retained Authorities

If a state or tribe [119] intends to take delegation of the federal plan, the state or tribe should submit to the appropriate EPA Regional Office a written request for delegation of authority. The state or tribe should explain how it meets the criteria for delegation. These criteria are explainedgenerally in the ''Good Practices Manual for Delegation of NSPS and NESHAP'' (EPA, February 1983). The letter requesting delegation of authority to implement the federal plan should: (1) Demonstrate that the state or tribe has adequate resources, as well as the legal and enforcement authority to administer and enforce the program; (2) include an inventory of affected EGUs, which includes those that have ceased operation but have not been dismantled, an inventory of the affected units' air emissions, and a provision for state or tribal progress reports to the EPA; (3) certify that a public hearing has been held on the state or tribal delegation request; and (4) include a memorandum of agreement between the state or tribe and the EPA that sets forth the terms and conditions of the delegation, the effective date of the agreement and the mechanism to transfer authority. Upon signature of the agreement, the appropriate EPA Regional Office would publish an approval documentin the **Federal Register**, thereby incorporating the delegation of authority into the appropriate subpart of 40 CFR part 62. *See also* EPA's Delegations Manual, Delegation 7–139, ''Implementation and Enforcement of 111(d)(2) and 111(d)(2)/129(b)(3) federal plans.'' (A copy of this delegation has been placed in the docket for this action.)

If authority is not delegated to a state or tribe, the EPA will implement the federal plan. Also, if a state or tribe fails to properly implement a delegated portion of the federal plan, the EPA will assume direct implementation and

[115] As discussed in section VI.D of this preamble, tribes with affected EGUs in their areas of Indian country can apply for TAS for the purpose of developing and seeking EPA approval of a tribal implementation plan (TIP) implementing the EG, but are not required to do so.

[116] As discussed in section VI.D of this preamble, in adopting a federal plan implementing the EGs in areas of Indian country containing affected EGUs, the EPA must determine that such a plan is ''necessary or appropriate'' to protect air quality. *See* 40 CFR 49.11(a).

[117] If the Administrator chooses to retain certain authorities under a standard, those authorities cannot be delegated, *e.g.,* the authority to allow alternative methods of demonstrating compliance.

[118] We note that issuance of a title V permit is not equivalent to the approval of a state plan or delegation of a federal plan. This has been discussed in prior rulemakings, *see, e.g.,* Proposed Federal Plan for Commercial Industrial Solid Waste Incinerators (CISWI) (67 FR 70640, 70652; November 25, 2002); Final Federal Plan for CISWI (68 FR 57518, 57535; October 3, 2003).

[119] A tribe interested in taking delegation of the federal plan must also apply, and be approved by the EPA, for TAS eligibility for that purpose. *See* 40 CFR part 49.

enforcement of that portion. The EPA will continue to hold inspection, information gathering, enforcement, and other parallel authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. In all cases where the federal plan is delegated, the EPA may retain and not transfer authority to a state or tribe to approve certain items promulgated in the 2015 CAA section 111(d) Clean Power Plan.

This proposed federal plan also specifies that EGU owners or operators who wish to petition the agency for any alternative requirement should submit a request to the Regional Administrator with a copy sent to the appropriate state.

B. Mechanisms for Transferring Authority

There are two mechanisms for transferring implementation authority to state and local agencies and tribes: (1) EPA approval of a state or tribal plan after the federal plan is in effect; and (2) if a state or tribe does not submit or obtain approval of its own plan, EPA delegation to a state or tribe of the authority to implement certain portions of this federal plan to the extent appropriate and if allowed by state or tribal law. Both of these options are described in more detail below.

1. Federal Plan Becomes Effective Prior To Approval of a State or Tribal Plan

After EGUs in a state or area of Indian country become subject to the federal plan, the state or local agency or tribe may still adopt and submit a plan to the EPA. If the EPA determines that the state or tribal plan is satisfactory and approvable pursuant to the EGs, the EPA will approve the state or tribal plan. If the EPA, on review of the submitted state or tribal plan, determines that this is not the case, the EPA will disapprove the plan and the EGUs covered in the state or tribal plan would remain subject to the federal plan until a state or tribal plan covering those EGUs is approved and effective. Prior to disapproval, the EPA will work with states and eligible tribes to attempt to reconcile areas of the plan that are unapprovable.

Upon the effective date of an approved state or tribal plan, the federal plan would no longer apply to EGUs covered by such a plan and the state or local agency, or the tribe, would implement and enforce the state or tribal plan in lieu of the federal plan. The timing of effectiveness of an approved state or tribal plan in this circumstance may depend in part on the need to ensure a smooth transition and maintain regulatory certainty. Thus, for example, under a mass-based federal plan, we propose to handle these transitions so that they coincide with the compliance periods. The approval of a state or tribal plan would also involve a public comment process, which would give interested stakeholders including any affected EGUs, the opportunity to comment. This will assist in ensuring that compliance, program integrity, electric reliability, and other critical factors are maintained. When an EPA Regional Office approves a state or tribal plan, it will amend the appropriate subpart of 40 CFR part 62 or 40 CFR part 49, respectively, to indicate such approval, as well as the timing of its effectiveness.

As discussed elsewhere in this document, the EPA may also in certain circumstances approve a partial state or tribal plan (sometimes called an ''abbreviated state plan'') that may modify certain limited provisions in the federal plan trading program. For example, this could occur if a state or tribe wishes to handle the initial allocation of allowances in a mass-based trading program, as discussed in section V.E of this preamble. The partial state or tribal plan would allow for the state or tribe to assume direct authority for administering and implementing this aspect of the trading program, while the remainder of the federal plan remains in place. The procedural and submission requirements set forth in the framework regulations of 40 CFR part 60, subpart B and the EGs would generally apply to a partial state or tribal plan, just as they would a full state or tribal plan. The scope of the requirement, however, would be commensurate with the scope of the partial plan. For instance, if a state or tribe seeks approval of a partial plan solely to handle allowance allocations, then the required statement of legal authority would be limited to those legal authorities the state or tribe must have to implement and enforce this component of the trading program.

2. State or Tribe Takes Delegation of the Federal Plan

The EPA, in its discretion, may delegate to state or tribal air agencies the authority to implement this federal plan. As discussed above, the EPA believes that it is advantageous and the best use of resources for state or local agencies or tribes to agree to undertake, on the EPA's behalf, administrative and substantive roles in implementing the federal plan to the extent appropriate and where authorized by state or tribal law. If a state or tribe requests delegation, the EPA will generally delegate the entire federal plan to the state or tribal agency, thereby providing authority to the state or tribe for things such as administration and oversight of compliance reporting and recordkeeping requirements, inspections of its affected EGUs, and enforcement. The EPA will continue to hold inspection, information gathering, enforcement, and other authorities along with the state or tribe even when a state or tribe has received delegation of the federal plan. The delegation will not include any authorities retained by the EPA.

C. Implementing Authority

The EPA Regional Administrators have been delegated the authority for implementing the federal plan. All reports required by the federal plan should be submitted to the appropriate Regional Administrator. Section II.B of this preamble includes Table 2 that lists names and addresses of the EPA Regional Office contacts and the states they cover.

With respect to the administration of a federal trading program in any final federal plan for a state or tribe, group of states or combined group of states and tribes, the Office of Air and Radiation within the Headquarters of the EPA is proposed to be the primary office within the agency with delegated CAA section 111(d)(2) authority. *See* Delegation 7–139, section 3(c).

D. Necessary or Appropriate Finding for Affected EGUs in Indian Country

Indian Tribes may, but are not required to, submit tribal plans to implement the EGs. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing the EGs. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). We invite tribes with EGU in their area of Indian country to comment on the level of their interest, if any, in developing their own plans.

The EPA is proposing in this action to find that it is necessary or appropriate to regulate affected EGUs in each of the three areas of Indian country that have affected EGUs under the proposed federal plan. The EPA is authorized to directly implement the EGs in Indian country when it finds, consistent with the authority of CAA section 301 which the EPA has exercised in 40 CFR 49.11, that it is necessary or appropriate to do so. In the final EGs, the EPA establishes emission performance rates for the four EGUs located in Indian country and mass- and rate-based emission goals for each of the three affected areas of Indian country. These areas include lands of the Navajo Nation's reservation, lands of the Ute Tribe of the Uintah and Ouray Reservation, and lands of the Fort Mojave Tribe's reservation. The EPA proposed carbon pollution EGs for EGUs in these areas and U.S. Territories in a Supplemental Notice of Proposed Rulemaking. *See* 79 FR 65482 (November 4, 2014). The four facilities with affected EGUs located in Indian country that the EPA identified in the Supplemental Notice are: The South Point Energy Center, on the Fort Mojave Reservation geographically located within Arizona; the Navajo Generating Station, on the Navajo Indian Reservation geographically located within Arizona; the Four Corners Power Plant, on the Navajo Indian Reservation geographically located within New Mexico; and the Bonanza Power Plant, on the Uintah and Ouray Indian Reservation geographically located within Utah. The emission performance targets for these areas were finalized along with those for EGUs located in the rest of the country in the final EGs.

In this action, we are proposing to find that it is necessary or appropriate, in each of the three areas of Indian country that have affected EGUs, to establish a federal plan that applies to the four power plants located on the Navajo Nation, the Fort Mojave Indian Reservation, and the Uintah and Ouray Reservation of the Ute Tribe. The affected EGUs located on the Navajo Nation are in an area of Indian country located within the continental United States, are interconnected with the western electricity grid, and are owned and operated by entities that generate and provide electricity to customers in several states. The affected EGU located on the Uintah and Ouray Reservation of the Ute Tribe is in an area of Indian country located within the continental United States, is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. The affected EGU located on the Fort Mojave Indian Reservation is in an area of Indian country located within the continental United States, is interconnected with the western electricity grid, and is owned and operated by an entity that generates and provides electricity to customers in several states. To date, none of the three tribes on whose areas of Indian country the four power plants are located have expressed a clear intent to develop and seek approval of a tribal implementation plan. Thus, absent a federal plan, the significant emissions from these four power plants could go unregulated by the Clean Power Plan.

Because the agency has finalized emission performance targets for these power plants in the EGs, there is, in our view, little benefit to be had by not proposing to include them in a federal plan now and a potentially significant downside to not doing so; the reductions the EPA has determined are achievable in the EGs would become more difficult and costly for these power plants to achieve if they are delayed in entering into the trading program the agency intends to establish. In order to meet the performance targets, we are anticipating that the affected EGUs may need to secure allowances or ERCs (depending on the approach ultimately finalized) during the compliance periods. They may also be able to generate and sell compliance instruments by participating in the trading program. Thus, proposing a finding that it is necessary or appropriate to establish one or more federal plans providing the ability to participate in a rate- or mass-based trading program is in the interest of these four power plants located in areas of Indian country. We believe that this together with the facts that, as indicated above, all four EGU are interconnected with the western electricity grid and are owned and operated by an entity that generates and provides electricity to customers in several states thereby making it potentially disruptive and inequitable not to include them in one or more federal plans on the same schedule as other affected EGU strongly supports proposing to find that it is necessary or appropriate to establish one or more applicable federal plans at this time.

We recognize that the governments of these tribes may still choose to seek TAS to develop a tribal plan, and this proposed determination does not preclude the tribes from taking such actions. We also note that this proposed determination does not preclude these tribes from seeking TAS and receiving delegation to administer aspects of any applicable federal plan that is ultimately promulgated. In the event a federal plan is needed, proposing a necessary or appropriate finding at this time will allow the EPA to expeditiously promulgate a final federal plan for one or all of these power plants in the future to allow trading to occur. We will continue to consult with the governments of the Navajo Nation, Fort Mojave Indian Tribe, and the Ute Tribe of the Uintah and Ouray Reservation during the comment period for this proposal, and prior to taking any action to finalize a necessary or appropriate finding and/or a federal plan. Comments on the appropriateness of the proposed finding should be submitted within the comment period specified in the **DATES** section of this preamble.

VII. Amendments To Process for Submittal and Approval of State Plans and EPA Actions

As indicated in the final rulemaking action for the CAA section 111(d) guideline, ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,'' in this action, in addition to the proposed federal plans and model trading rules, the EPA is also proposing to amend the framework regulations and update the process for acting on CAA section 111(d) state plans under 40 CFR part 60, subpart B. These changes would be applicable to any future CAA section 111(d) rules going forward, not just the Clean Power Plan EGs. The EPA proposes six changes to the CAA section 111(d) process in the framework regulations to include: (1) Partial approval/disapproval mechanisms similar to CAA section 110(k)(3); (2) a conditional approval mechanism similar to CAA section 110(k)(4); (3) a mechanism for the EPA to make calls for plan revisions similar to the ''SIP-call'' provisions of CAA section 110(k)(5); (4) an error correction mechanism similar to CAA section 110(k)(6); (5) completeness criteria and a process for determining completeness of state plans and submittals similar to CAA section 110(k)(1) and (2); and (6) updates to the deadlines for the EPA action. In addition, in this section, the agency is proposing an interpretation regarding the effect under section 111 if an existing facility subject to CAA section 111(d) modifies or reconstructs. We believe these changes will significantly streamline the state plan review and approval process, be more respectful of state processes, and generally enhance the administration of the CAA section 111(d) program.

CAA section 111(d)(1) provides that the EPA ''shall establish a procedure similar to that provided by CAA section [110] of this title under which each state shall submit to the Administrator a [111(d)] plan. . . .'' 42 U.S.C. 7411(d)(1). Thus, the CAA directs the EPA to look to the structure of the SIP program when designing the procedures the states and agency will use to develop CAA section 111(d) plans. Notably, the CAA does not require the CAA section 111(d) procedures to be identical to those the EPA uses under

CAA section 110 for SIPs.[120] Therefore, the EPA interprets CAA section 111(d) to provide the EPA flexibility in designing procedures that reflect the structure of those used under CAA section 110 for implementation plans, without requiring the EPA to exactly track SIP procedures when acting on section 111(d) plans.

As a general matter these proposed changes would simply update the CAA section 111(d) framework regulations to include several new, more flexible procedural tools that Congress introduced into section 110 in the 1990 CAA Amendments. The basic procedures in the CAA section 111(d) framework regulations were promulgated in 1975 based on the structure of CAA section 110 as Congress designed it in the 1970 CAA. *See* 40 FR 53340–49 (November 17, 1975). Over the years since 1970, the EPA and the states learned a great deal about the procedural limitations of the original SIP review process. The 1970 CAA only allowed the EPA two choices—to approve or disapprove SIP submittals. The agency struggled to deal responsively to situations where the EPA wanted to work with states to get state programs approved to the extent possible, while maintaining consistency with CAA requirements. Congress responded in 1990 and enhanced the procedural mechanisms the EPA has to act on SIPs. The EPA is proposing correspondingly to update the CAA section 111(d) regulations in a similar fashion. Currently, the EPA's framework regulations for submittal and adoption of CAA section 111(d) state plans do not explicitly provide for the EPA to use some of the same procedures for approving or disapproving state plans Congress introduced into the SIP program in the 1990 CAA Amendments. The EPA is proposing to amend the procedures for approval or disapproval of CAA section 111(d) state plans to reflect the enhancements Congress included in CAA section 110 for agency actions on SIPs. These proposed amendments are discussed in more detail below.

A. Partial Approvals/Disapprovals

First, the EPA proposes to add authority similar to that under CAA section 110(k)(3) to partially approve or disapprove a plan.[121] This is a particularly useful function when much of a state plan is approvable and the EPA and the state cannot reach resolution on only a small, severable portion of the state plan. In this case, the EPA prefers not to be in a position where it must disapprove the full plan, but rather to allow the state to move forward with those portions of the plan that are approvable. This approach would also address those situations where the state wishes to take over a discrete part of a federal plan. For instance, in this proposal, states will be able to seek approval of a partial state plan that will give them the ability to handle the allocation of allowances under a mass-based federal plan.

In cases where elements of a plan are functionally severable from each other, and one element is approvable while another is not, this provision will authorize the EPA to approve one part of a plan and disapprove the other. It will also authorize the EPA to accept and review a state plan that is only partial in nature, if identified by the state as such, so long as the other applicable submission requirements are met (such as demonstration of legal authority and completion of the public process). When the state submits what it intends to be a full state plan (rather than just a partial plan), the EPA proposes that the approvable portion of a plan must be functionally severable from the rest of the plan. This will be the case when the following conditions are met. First, the approvable portion of the plan must not depend on the rest of the plan. In other words, the disapproval of the remaining portion of the plan must not affect the portion that is approved. Second, approval of the approvable portion must not alter the function of the submittal in a way that is contrary to the state's intent.

The partial disapproval would be a disapproval for the purposes of CAA section 111(d)(2)(A) and would trigger the EPA's authority to issue a federal plan for the state, at least for that part of the plan that was disapproved. Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to implement as much of its program as is consistent with a CAA section 111(d) guideline and may reduce the scope of any federal plan that would be necessary.

B. Conditional Approvals

The second mechanism is the authority under CAA section 110(k)(4) to conditionally approve a plan. Where a state has submitted a plan that substantially meets the requirements of a CAA section 111(d) emission guideline, but requires some specific amendments to make it fully approvable, this provision authorizes the EPA to conditionally approve the plan. The Governor or his/her designee must submit to the EPA a commitment that specifies the amendments to be adopted and submitted to the EPA by no later than 1 year from the effective date of the conditional approval. If the state fails to meet its commitment, the conditional approval is treated as a disapproval. Incorporating this mechanism under the framework regulations for CAA section 111(d) will enable the EPA to approve a state to begin to administer a substantially complete program that requires only specific changes to be fully approvable. This provision is designed to authorize a state with a substantially complete and approvable program to begin implementing it, while promptly amending the program to ensure it fully complies with CAA section 111(d).

C. Calls for Plan Revisions

CAA section 110(k)(5) authorizes the EPA to find that a SIP does not comply with the requirements of the CAA. To date, the EPA has not considered using a similar procedure pursuant to the authority under CAA section 111(d). We now propose to do so. The ability to call for plan revisions is fundamental to a program that will be implemented over many years or multiple decades. Under the Clean Power Plan EGs, states have more than a decade to fully implement emissions standards or state measures in order to ensure affected EGUs achieve the emission goals of the EGs. Throughout this period, the EPA and the states will be monitoring their programs to ensure they are achieving the intended results. It is possible that design assumptions about the effect of control measures the states incorporate into their plans could prove inaccurate in retrospect and could result over time in the plan not meeting the emission reductions required by the EGs. In that case, having a procedural mechanism available under CAA section 111(d) similar to the so-called ''SIP call'' mechanism in CAA section 110(k)(5) will allow the agency to initiate a process with the state to make necessary

[120] *See* Webster's II New Riverside University Dictionary (Riverside 1988) (defining ''similar'' to mean ''resembling though not completely identical'').

[121] We recognize that the regulations appear to already contemplate partial approval/disapprovals to some extent. *See* 40 CFR 60.27(a) (''The Administrator may . . . extend the period for submission of any plan . . . or *portion* thereof.'') (emphasis added). We note that this language only allows for extensions of time with respect to portions of state plan submissions and may not sufficiently authorize a permanent partial approval. The proposed enhancement will resolve any ambiguity that partial approvals/disapprovals are an acceptable mechanism under CAA section 111(d).

revisions to ensure the plan functions properly.

Accordingly, the EPA is proposing to amend the framework regulations to include a provision similar to CAA section 110(k)(5) under which the EPA may find that a state's CAA section 111(d) plan is substantially inadequate to comply with the requirements of the CAA and require the state to revise the plan as necessary to correct such inadequacies. Consistent with CAA section 110(k)(5), the EPA shall notify the state of any inadequacies and establish a reasonable deadline for the state to submit required plan revisions. That deadline will not exceed 18 months after the date of the action. The EPA will make its finding and notice to the state available to the public.[122]

The effect of such a finding is that either the state submits the program corrections by the date the EPA sets in the document, or pursuant to CAA section 111(d)(2)(A), the EPA has authority to issue a federal plan for a state that misses its deadline to correct its plan. In effect, the finding of plan inadequacy establishes a plan submittal deadline subject to the provisions of CAA section 111(d)(2)(A). A finding of failure to meet that new deadline triggers the EPA's authority to issue a federal plan for the state. The EPA may promulgate a federal plan at any time following the state's failure to timely submit an adequate plan that addresses the EPA's finding.

While these authorities are important, the intention of having a mechanism to call for plan revisions is to have a way to initiate an orderly process to improve plans when they are not meeting program objectives. It is the EPA's hope that a call for plan revision leads to a constructive dialogue with a state or states, and ultimately, an improved and more effective CAA section 111(d) plan.

The EPA is also proposing that the agency can call for a plan revision in circumstances where a state is not implementing its approved state plan and, therefore, the state plan is substantially inadequate to provide for the implementation of CAA section 111(d) standards of performance. As discussed above, the CAA directs the EPA to develop a procedure for state plans under CAA section 111(d) similar to CAA section 110 SIP procedures. Calling a plan that is substantially inadequate to provide for implementation of standards of performance (*i.e.,* there is a failure to implement a state plan) is one area where the EPA proposes it is appropriate to adapt the procedural mechanisms available in the SIP program to provide a similar process that assures effective state plan implementation under CAA section 111(d). Under CAA section 110(k)(5), the EPA may call for a revision of a state plan ''[w]henever the Administrator finds that the . . . plan . . . is substantially inadequate to . . . comply with any requirement of [the Act].'' If the state does not submit a plan revision in response to the call to cure the failure to provide for implementation, the EPA would have the authority to promulgate the federal plan being proposed.

One critical requirement of CAA section 111(d)(1)(B) is that a state must submit a plan that ''provides for the *implementation and enforcement* of such standards of performance'' (emphasis added). If, after the EPA has approved a plan, a state fails to implement that plan, the plan has become substantially inadequate to comply with this requirement of the CAA. Under this proposal, the EPA's remedy would be to find the plan is substantially inadequate, which triggers the state's obligation to cure, and failing that, the EPA's authority to promulgate the federal plan.

In the alternative, the EPA proposes that this authority to call a plan for failure to implement is anchored in the authority provided under CAA section 110(k)(5) to call a SIP when the agency finds that it is ''substantially inadequate to attain or maintain the relevant national ambient air quality standard.'' In the context of CAA section 111, this authority translates into the EPA calling a state plan when the agency finds that it is substantially inadequate to achieve the emission reductions required under the EGs. If a state has failed to implement its plan, and that failure is pervasive enough to render the requirements of the plan ineffective, it is reasonable for the EPA to find that the state plan is substantially inadequate to achieve the emission reductions required under the EGs. The state's failure to implement has revised the effect of the plan so that it is no longer adequate to meet the CAA's requirements.

D. Error Corrections

The fourth mechanism is the error correction authority under CAA section 110(k)(6). Where the EPA concludes that it has erroneously approved, disapproved, or promulgated a plan or plan revision (or part thereof), this section authorizes the agency to revise its action, in the same manner as the original action, without requiring any further submission from the state. Prior to the 1990 CAA Amendments, there was some question whether the EPA could unilaterally correct a previous action on a SIP submittal without the state having to submit a new SIP. This limitation imposed unnecessary burdens on states to fix even obvious errors, because CAA section 110(a)(2) requires the state to provide notice and a public hearing on each new SIP submittal. Incorporating this mechanism into the CAA section 111(d) framework regulations will allow the EPA to fix errors in its prior actions on state plans without imposing on the states the corresponding burden of providing notice and a public hearing as required under the CAA section 111(d) framework regulations. *See* 40 CFR 60.23.

E. Completeness Criteria

Completeness criteria provide the agency with a means to determine whether a submission by a state includes the minimum elements that must be met before the EPA is required to act on such submission. When submittals do not contain the necessary minimum elements, then the EPA may, without further action, find that a state has failed to submit a plan. This determination is ministerial in nature and requires no exercise of discretion or judgment on the agency's part, nor does it reflect a judgment on the sufficiency or adequacy of the submitted portions of a state plan. The task is accomplished by simply comparing the materials provided by the state as its submittal against the required criteria to determine whether the plan is complete or not. In the case of SIPs under CAA section 110(k)(1), the EPA promulgated completeness criteria in 1990 at Appendix V to 40 CFR part 51 (55 FR 5830; February 16, 1990). The EPA proposes to adopt criteria similar to the criteria set out at section 2.0 of Appendix V for determining the completeness of submissions under CAA section 111(d). The completeness criteria can be grouped into: (1) Administrative materials; and (2) technical support. The EPA proposes that both groups would apply to all CAA section 111(d) rules going forward. The agency notes that the addition of completeness criteria in the framework regulations does not alter any of the submission requirements states already have under the EGs.

For administrative materials, the EPA is proposing completeness criteria that mirror the existing administrative criteria for SIP submittals because the two programs have similar

[122] Consistent with the agency's practice under CAA section 110(k)(5), the EPA anticipates that a call for plan revisions under CAA section 111(d) will be done via notice and comment rulemaking.

administrative processes. The EPA proposes that a complete final state plan submittal under CAA section 111(d) must include: (1) A formal letter of submittal from the Governor or his/her designee requesting EPA approval of the plan or revision thereof; (2) evidence that the state has adopted the plan in the state code or body of regulations (That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date.); (3) evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) a copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation/document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the state (The effective date of the regulation/document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan.); (5) evidence that the state followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption/issuance of the plan; (6) evidence that public notice was given of the proposed change with procedures consistent with the requirements of 40 CFR 60.23, including the date of publication of such notice; (7) certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23; and (8) compilation of public comments and the state's response thereto.

These criteria, as proposed, are intended to be generic to all CAA section 111(d) plans going forward, with the proviso that specific EGs may provide otherwise. The technical support completeness criteria that the EPA proposes will also be generic to all CAA section 111(d) rules, with the same proviso. The EPA proposes that the technical support required for all plans must include each of the following: (1) Description of the plan approach and geographic scope; (2) identification of each designated facility, identification of emission standards for each designated facility, and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) identification of compliance schedules and/or increments of progress; (4) demonstration that the state plan submittal is projected to achieve emissions performance under the applicable EGs; (5) documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

The EPA proposes a process similar, though not identical, to that set forth in 40 CFR 51.103 and Appendix V to 40 CFR part 51 to make completeness determinations. Similar to CAA section 110(k)(1)(C), under this proposal, where the EPA determines that a state submission required under CAA section 111(d) does not meet the minimum completeness criteria we are proposing to establish, the state will be considered to have not made the submission. The EPA further proposes that, similar to CAA section 110(k)(1)(B), within 60 days of the EPA's receipt of a state submission, but no later than 6 months after the date, if any, by which a state is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria have been met. Any plan or plan revision that a state submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. In cases where a state does not submit anything to the agency, however, the Administrator must make a finding of failure to submit no later than 6 months after the date, if any, by which a state is required to submit the plan or revision. (In other words, ''completeness by operation of law'' is only available where the state has actually submitted a plan to the agency.)

As with the completeness determination process for SIP submissions, the EPA's determination that a submittal is complete is not a finding that the submittal meets the substantive requirements of CAA section 111(d) or the guideline. That must be done via the process for approval or disapproval of a state plan, which would be done through notice and comment rulemaking. In the completeness process, the EPA will confirm that a state's submittal appears to have addressed the criteria for a complete submittal and, therefore, the submittal is sufficient to trigger the EPA's obligation to act on it. But in the completeness process the agency will not assess the content of those submissions to determine if they are approvable. Accordingly, even when the EPA affirmatively determines that a submittal is complete, it does not prevent the agency from later finding that the state plan does not meet the requirements of the EGs, including finding that the submittal failed to address a required element and must be disapproved.

Similarly, when a submittal is determined to be complete by operation of law after 6 months without the EPA's affirmative determination of completeness, the only legal consequence is that the EPA now has an obligation to act on that submittal. Completeness by operation of law means that the submittal is deemed complete and requires the EPA's review, whether or not the state has actually addressed all the required elements. Accordingly, if the agency determines that a state has failed to address a required element in its submittal once the EPA begins review of the state plan that is complete by operation of law, the agency must go through the process of disapproving (or partially disapproving or conditionally approving, as discussed below) that plan, unless the state and the EPA work together to cure the deficiency. In other words, the EPA cannot simply find the plan incomplete and return it to the state at that point. But the finding of completeness by operation of law in no way prevents the EPA from subsequently concluding that the state's submission is missing a required element of the program and making that finding as part of a disapproval of the plan.

As described in the final rulemaking action for the CAA section 111(d) EGs, a state will submit all CAA section 111(d) plans electronically. If the EPA determines that any submission fails to meet the completeness criteria, the agency may return the plan to the state and request corrections, identifying the components that are absent or insufficient to allow the EPA to perform a review of the plan. The state will not have met its obligation to submit a final plan until it resubmits a revised state plan or supporting materials addressing the corrections the EPA identified in its incompleteness determination.

The EPA is also proposing to include an exception to the criteria for complete administrative materials in cases where a state and the EPA are ''parallel processing'' the final plan. Parallel processing allows a state to submit the plan prior to final adoption by the state and provides an opportunity for the state to consider the EPA's comments prior to submission of a final plan for final review and action. The EPA would propose to take action on a state plan based on a proposed state regulation. The EPA would only finalize the action if the state adopts a final plan that is legally effective under state law. The EPA would only approve the plan if the state addressed any corrections that the EPA identified in its proposed action on the state plan without any other material change to the plan. Note that a plan submitted for parallel processing must still meet all the criteria for technical completeness so that the EPA and the public have a sufficient basis on which to evaluate and comment on the EPA's proposed action.

F. Update to Deadlines for EPA Actions

The EPA proposes to update the deadlines for acting on state submittals and promulgating a federal plan under 40 CFR 60.27(b), (c), and (d) to more closely track the current versions of CAA sections 110(c) and 110(k) adopted in 1990. The framework regulations for CAA section 111(d) state plans currently are parallel to the prior version of CAA section 110. They require the EPA to act on a state plan or plan revision submittal within 4 months after the date required for submission of a plan or plan revision. *See* 40 CFR 60.27(b). The regulations then require the EPA to issue a proposed federal plan in certain circumstances after consideration of any state hearing record, *see* 40 CFR 60.27(c), and require the EPA to promulgate the proposed federal plan within 6 months after the date required for plan submissions, *see* 40 CFR 60.27(d).

The final CO_2 EGs for affected EGUs have already adjusted the deadline in 40 CFR 60.27(b) to require the EPA to act on a state plan under those EGs within 12 months (rather than 4 months) after the date required for submission of a plan. *See* 40 CFR 60.5715. However, the Clean Power Plan EGs did not modify the 6-month deadline for a federal plan in 40 CFR 60.27(d).

The EPA is proposing to amend 40 CFR 60.27(b) to allow the EPA 12 months to approve or disapprove submittals of all plans or plan revisions under CAA section 111(d), not just those related to the Clean Power Plan under 40 CFR 60.5715. This change would provide the EPA with sufficient time for the steps required to approve or disapprove the submittal, which include proposing the EPA's approval or disapproval of the plan or plan revision, a public comment period on the EPA's proposal, time for the EPA to review and respond to public comments, and the issuance of a final rule approving or disapproving the plan or plan revision.

The EPA is also proposing to amend 40 CFR 60.27(b) to specify that the deadline for the EPA to act on a plan or plan revision is 12 months after receipt of a complete plan or plan revision, rather than 12 months after the deadline for submittal of a plan or plan revision. This amendment will allow the EPA to have the full 12 months to act on submittals of complete plans or plan revisions.

The EPA also proposes slight modifications to the provision related to issuing a proposed federal plan in 40 CFR 60.27(c); changing the 6-month deadline for issuing a final federal plan in 40 CFR 60.27(d) to 1 year;[123] and, similar to the change in timing for 40 CFR 60.27(b) above, setting the deadline for promulgation of a federal plan to run from the date of the EPA's action on a state submittal, rather than from the original deadline for a state submittal.

The EPA believes it is appropriate to modify these timing requirements for several reasons. First, the EPA notes that under CAA section 111(d)(2), Congress gave the EPA the ''same'' authority to prescribe a federal plan under CAA section 111(d) as it would have under CAA section 110(c) in the case of a state failure to submit a SIP. The term ''same'' stands in contrast to the term ''similar'' in CAA section 111(d)(1) (discussed above). As with the use of the term ''similar,'' the EPA believes it is authorized by this language to follow the timing provisions of CAA section 110(c) as currently enacted. Second, as a general matter, the timing requirements of current 40 CFR 60.27(c) and (d), which effectively require the EPA to propose and finalize a federal plan within 6 months of the deadline for state submittals, may be outdated and unrealistic with respect to the timelines for review of state plans and the time periods for action, particularly as informed by the agency's experience with CAA section 110 SIPs (which led to the extension of the timelines and other changes to CAA section 110 in the 1990 Amendments discussed above). Third, in the Clean Power Plan EGs, the EPA has finalized a timing requirement that gives the agency a year to approve or disapprove a state plan or revision. The existing requirement in 40 CFR 60.27(d) that the EPA must promulgate a federal plan within 6 months of the initial deadline for state plans is therefore inconsistent with this provision. Fourth, existing 40 CFR 60.27(c) tracks the prior version of CAA section 110(c) with respect to the issuance of a proposed federal plan. This relatively prescriptive language is no longer present in CAA section 110(c). The procedural requirements for rulemakings under both CAA section 110 and 111(d) are set out in section 307(d) of the CAA, and the EPA believes those provisions are appropriate and adequate to guide its rulemaking process for CAA section 111(d) federal plans.

The EPA invites comment on all of these proposed changes to the framework regulations. The EPA notes that the addition of these mechanisms to the framework regulations will make them available for all CAA section 111(d) regulations, not just those under the Clean Power Plan at 40 CFR part 60, subpart UUUU.

G. Proposed Interpretation Regarding Existing Sources That Modify or Reconstruct

In the proposed rulemaking for the Clean Power Plan, the EPA proposed the interpretation that if an existing source is subject to a CAA section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. *See* 79 FR 34830, 34903–4 (June 18, 2014). The EPA did not finalize a position on this issue in the final EGs rule, but indicated that it would re-propose and request comment on this issue through this federal plan rulemaking. The EPA also stated deferral of action on this issue does not impact states' and affected EGUs' pending obligations under the final Emission Guidelines relating to plan submission deadlines, as this issue concerns potential obligations or impacts after an existing source has already become subject to the requirements of a state plan. The EPA intends to finalize its position on this issue through this rulemaking, which will be well in advance of the plan performance period beginning in 2022, at which point state plan obligations on existing sources are effectuated.

We noted in the Clean Power Plan proposal that CAA section 111(d) is arguably silent as to this issue. Thus, we

[123] As under CAA section 110, the EPA believes that, should it fail for whatever reason to meet a deadline by which it was to take action, such as issue a federal plan, under CAA section 111(d), that failure does not thereby obviate or in any way remove the EPA's authority or obligation to take that action. *See Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1224 (10th Cir. 2013) (''Although the statute undoubtedly requires that the EPA promulgate a FIP within two years, it does not stand to reason that it loses its ability to do so after this two-year period expires. Rather, the appropriate remedy when the EPA violates the statute is an order compelling agency action.'').

took this to grant the agency the authority to provide a reasonable interpretation to fill in the gaps where the statute is silent. In the proposal for the Clean Power Plan, we proposed to disallow existing sources to leave the CAA section 111(d) program through modification or reconstruction. We did this for two reasons. First, if a source did so, that could prove disruptive to the state plan. Second, allowing sources to do so could provide them an incentive that would be contrary to the purposes of CAA section 111(d). We then asked for comment on ''whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute.''

We received many comments disagreeing with this approach. After reviewing these comments, the agency believes an alternative interpretation is more appropriate in the particular context here. In order to give the public an opportunity to comment on this, we are proposing this interpretation here. That is, when CAA section 111(d) EGs are initially promulgated for existing stationary sources in response to corresponding CAA section 111(b) standards of performance for the same pollutant, the statute prevents new, modified, or reconstructed sources (including under those particular CAA section 111(b) standards of performance and as those terms are applied in the relevant new source performance standards (NSPS)) from simultaneously being subject to state plans under those particular CAA section 111(d) EGs. This interpretation gives meaning to the definition of ''existing source'' in CAA section 111(a)(6) and is consistent with the definition of ''new source'' in CAA section 111(a)(2). Further, it is consistent with the historical treatment of modified and reconstructed sources in the CAA section 111 program.

The EPA notes the concerns it noted in the proposal supporting why the originally proposed interpretation was reasonable are being addressed in other ways in the final EGs, and in the proposed federal plan. In other words, there will be other ways to minimize disruption to state plans if such a modification or reconstruction were to take place. We invite comment on the agency's proposed interpretation that when an existing source modifies or reconstructs in such a way that it meets the definition of a new source, for purposes of a particular NSPS and emission guideline, it becomes a new source under the statute and is no longer subject to the CAA section 111(d) program

H. Separate Finalization of These Changes

The agency intends to finalize these procedural changes and interpretation sooner than it finalizes the rest of this proposed action. The EPA believes these changes generally enhance and improve the framework regulations in a way that will be of benefit to the states, the EPA, and other stakeholders, and will improve the overall efficacy of the program. We believe it is important to finalize these changes to the framework regulations relatively quickly in order to provide states and other stakeholders predictability in how the EPA intends to process state plans and submissions under CAA section 111(d). If the EPA does finalize these changes sooner than the model trading rules or the federal plan, it will do so after the close of the comment period, and after consideration and response to any comments on these changes.

VIII. Impacts of This Action

A. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. *See* 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. *See* 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. *See* 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. *See* 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[124] Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. *Id.* To trigger a consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and if the effect is indirect, it must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of ESA section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are, like the EGs that it implements, positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (sulfur oxides and NO_X), for EGUs that will be covered by the federal plan. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation. The EPA has considered various types of potential effects in considering whether ESA consultation is required for this rule.

With respect to the projected GHG emission reductions, the EPA does not believe that such reductions trigger ESA consultation requirements under ESA section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection

[124] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25 (March 1998) (providing examples of direct effects: *e.g.*, driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

between GHG emissions and effects on the species in its habitat.[125] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the ESA section 7 regulations and, thus, are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2). In the final EGs, the agency noted that, although the GHG emission reductions projected for the EGs are large (estimated reductions of about 415 million short tons of CO_2 in 2030 relative to the base case), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected emission reductions over the lifetimes of the model years in question,[126] which are roughly five to six times those projected above and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements from the fuel efficiency rule relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact [of the specific federal action] on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).'' *Id. See also, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004). The EPA similarly proposes to determine that the likelihood of jeopardy to a species from this proposed action is extremely remote, and ESA does not require consultation. The EPA's proposed conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SO_2 and NO_X as a collateral consequence of this proposal (which will be, as stated above, only a subset of the total reductions from the EGs). However, CAA section 111(d) cannot directly control emissions of criteria pollutants. And furthermore, a federal plan under CAA section 111(d)(2) does no more than prescribe emissions standards of the same stringency as the corresponding EGs. *See* 40 CFR 60.27(e)(1). Consequently, CAA section 111(d) provides no discretion to set a standard in a federal plan based on potential impacts to endangered species of reduced criteria pollutant emissions. ESA section 7(a)(2) consultation is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also WildEarth Guardians* v. *U.S. Envt'l Protection Agency,* 759 F.3d 1196, 1207–10 (10th Cir. 2014) (the EPA has no duty to consult under section 7 of the ESA regarding HAP controls that it did not require—and likely lacked authority to require—in a FIP for regional haze controls under section 169A of the CAA.).

Finally, the EPA has also considered other potential effects of the rule (beyond reductions in air pollutants) and whether any such effects are ''caused by'' the rule and ''reasonably certain to occur'' within the meaning of the ESA regulatory definition of the effects of an action. *See* 50 CFR 402.02. The EPA recognizes, for instance, that questions may exist whether decisions such as increased utilization of solar or wind power could have effects on listed species. The EPA received comments on the EGs asserting that because potential increased reliance on wind or solar power may be an element of Building Block 3, and because wind and solar facilities may in some cases have effects on listed species, the EPA must consult under the ESA on this aspect of the rule.

The EPA has carefully considered the comments and the correspondence from Congress as well as the case law and other materials cited in those documents. The EPA does not believe that the effects of potential future changes in the energy sector—including increased reliance on wind or solar power as a result of future potential actions by states or other implementing entities—or any potential alterations in the operations of any particular facility would, at the time of promulgation of a federal plan, be sufficiently certain to occur so as to require ESA consultation on the rule. The EPA appreciates that the ESA regulations call for consultation where actions authorized, funded, or carried out by federal agencies may have indirect effects on listed species or designated critical habitat. However, as noted above, indirect effects must be caused by the action at issue and must be reasonably certain to occur.

Under a federal plan, it is the EPA that would implement a CAA section 111(d) plan. The EPA believes that even with this proposed federal plan, any effects on listed species or designated habitat are too uncertain to require consultation under ESA section 7. This is so for at least two reasons: (1) The EPA cannot know with any certainty at this stage which states will actually become subject to a finally promulgated federal plan. Which affected EGUs, in which states, will be covered by this plan can only be known after states have failed to submit a plan, or have had their plans disapproved by the EPA; and (2) the federal plan as proposed will be implemented through some form of emissions trading. Emissions trading inherently provides maximum flexibility to individual affected EGUs to choose their method of compliance, including continuing to emit the relevant pollutant at historical rates so long as the affected EGU holds sufficient credits or allowances. At this point, the EPA has no meaningful information to express in any more than the broadest terms how any particular affected EGU may choose to comply with the federal plan, should it be promulgated for them based on their location in an area not covered by an approved state plan. The Services have explained that ESA section 7(a)(2) was not intended to preclude federal actions based on potential future speculative effects.[127]

[125] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (October 3, 2008).

[126] *See* 75 FR 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (October 15, 2012).

[127] *See* 51 FR 19933 (describing effects that are ''reasonably certain to occur'' in the context of consideration of cumulative effects and distinguishing broader consideration that may be appropriate in applying a procedural statute such as the National Environmental Policy Act, as opposed to a substantive provision such as ESA section 7(a)(2) that may prohibit certain federal actions); Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–30 (March 1998) (in the same context, describing indicators that an activity is reasonably certain to occur as including governmental approvals of the action or indications that such approval is imminent, project sponsors' assurance that the action will proceed, obligation of venture capital, or initiation of contracts; and noting that the more governmental

These are precisely the types of speculative future activities and effects currently at issue here. The EPA requests comment on its proposed conclusion that ESA section 7 consultation is not required for this action. The EPA will continue to evaluate the scope and potential effects of federal planning activities for this source category to the extent federal plans are needed and implemented in specific areas and over specific sources.

B. What are the air impacts?

The EPA anticipates significant emission reductions under this proposed action for the utility power sector. Specifically, the EPA is proposing approaches in the form of mass- and rate-based trading options that provide flexibility in implementing emission standards for a state's affected EGUs. Both proposed approaches to the federal plan would require affected EGUs to meet emission standards set using the CO_2 emission performance rates in the Clean Power Plan EGs.

However, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan or will adopt a model rule. Because of this lack of information, in the Regulatory Impact Analysis (RIA) for this proposal, the EPA chose to examine a scenario where all states of the contiguous United States will be regulated under a federal plan or will adopt the model rule. Additionally, we examine two alternative federal plan approach scenarios. The first federal plan approach assumes all states in the contiguous United States are regulated under a rate-based federal plan. The second federal plan approach assumes all contiguous states are regulated under a mass-based federal plan.[128]

Under the rate-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 22 percent in 2020, 28 percent in 2025, and 32 percent in 2030. Under the mass-based approach, when compared to 2005, CO_2 emissions are projected to be reduced by approximately 23 percent in 2020, 29 percent in 2025, and 32 percent in 2030. The proposal is projected to result in substantial co-benefits through reductions of SO_2, NO_X, and $PM_{2.5}$ that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Table 12 and Table 13 of this preamble show expected CO_2 and other air pollutant emissions in the base case and reductions under the proposal for 2020, 2025, and 2030 for both rate-based and mass-based approaches.

TABLE 12—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER RATE-BASED FEDERAL PLAN APPROACH

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Rate-based Federal Plan Approach	2,085	1,297	1,282
Emission Reductions	69	14	50
2025			
Base Case	2,165	1,275	1,302
Rate-based Federal Plan Approach	1,933	1,097	1,138
Emission Reductions	232	178	165
2030			
Base Case	2,227	1,314	1,293
Rate-based Federal Plan Approach	1,812	996	1,011
Emission Reductions	415	318	282

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

TABLE 13—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED FEDERAL PLAN APPROACH

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
2020			
Base Case	2,155	1,311	1,333
Mass-based Federal Plan Approach	2,073	1,257	1,272
Emission Reductions	81	54	60
2025			
Base Case	2,165	1,275	1,302
Mass-based Federal Plan Approach	1,901	1,090	1,100

administrative discretion remains to be exercised, the less there is reasonable certainty the action will proceed).

[128] It is important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented may not be indicative of likely differences between the approaches. If one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

TABLE 13—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS FROM THE BASE CASE UNDER MASS-BASED FEDERAL PLAN APPROACH—Continued

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
Emission Reductions	265	185	203
2030			
Base Case	2,227	1,314	1,293
Mass-based Federal Plan Approach	1,814	1,034	1,015
Emission Reductions	413	280	278

Source: Integrated Planning Model, 2015.
Note: Emissions may not sum due to rounding.

The reductions in Tables 12 and 13 of this preamble do not account for reductions in HAP that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

C. What are the energy impacts?

The proposed action may have important energy market implications. Table 14 of this preamble presents a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in section VIII.B of this preamble and presented in the RIA for this proposal.

TABLE 14—SUMMARY TABLE OF IMPORTANT ENERGY MARKET IMPACTS FOR RATE-BASED AND MASS-BASED FEDERAL PLAN APPROACHES

[Percent change from base case]

	Rate-Based			Mass-Based		
	2020	2025	2030	2020	2025	2030
Retail electricity prices	3%	1%	1%	3%	2%	0%
Average electricity bills	3	−4	−7	2	−3	−8
Price of coal at minemouth	−1	−5	−4	−1	−5	−3
Coal production for power sector use	−5	−14	−25	−7	−17	−24
Price of natural gas delivered to power sector	5	−8	2	4	−3	−2
Natural gas use for electricity generation	3	−1	−1	5	0	−4

These figures reflect the EPA's modeling that presumes policies that lead to generation shifts and growing use of DS–EE and renewable electricity generation out to 2029. If different implementation choices are made than those modeled, impacts could be different.

D. What are the compliance costs?

The compliance costs of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and modeled federal plan approaches described in section VIII.B of this preamble and presented in the RIA for this proposal. The incremental cost is the projected additional cost of complying with the proposed action in the year analyzed and includes the amortized cost of capital investment, needed new capacity, shifts between or among various fuels, deployment of DS–EE programs, and other actions associated with compliance. These important dynamics are discussed in more detail in the RIA in the rulemaking docket.

The EPA estimates the annual incremental compliance cost for the rate-based federal plan approach to be $2.5 billion in 2020, $1.0 billion in 2025 and $8.4 billion in 2030. The EPA estimates the annual incremental compliance cost for the mass-based federal plan approach to be $1.4 billion in 2020, $3.0 billion in 2025, and $5.1 billion in 2030. More detailed cost estimates are available in the RIA in the rulemaking docket.

E. What are the economic and employment impacts?

Based on the analysis presented in the RIA, the proposed action is projected to result in certain changes to power system operation as a compliance approach with the standards. See Table 14 of this preamble for a variety of important energy market impacts for 2020, 2025, and 2030 under both the rate-based and mass-based federal plan approaches described in Section VIII.B of this preamble and presented in the RIA for this proposal.

Changes in price or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in the cost of production may result in changes in prices, quantities produced, and profitability of affected firms. The EPA recognizes that the EGs provide significant flexibilities and states implementing the EGs may choose to mitigate impacts to some markets outside the utility power sector. Similarly, demand for new generation or DS–EE as a result of states implementing the guidelines can result in shifts in production and profitability for firms that supply those goods and services.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. While the economy continues to move toward full employment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

The EPA's employment analysis includes projected employment impacts associated with modeled federal plan approaches for the electric power industry, coal and natural gas production, and DS–EE activities. These projections are derived, in part, from a detailed model of the utility power sector used for this regulatory analysis, and U.S. government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that the proposed action could result in a net decrease of approximately 25,000 job-years in 2025 under the rate-based federal plan approach and approximately 26,000 job-years in 2025 under the mass-based approach. For 2030, the estimates of the net decrease in job-years are 31,000 under the rate-based approach and 34,000 under the mass-based approach. The agency is also offering an illustrative calculation of potential employment effects due to DS–EE programs. Employment impacts from DS–EE programs in 2030 could range from approximately 52,000 to 83,000 jobs under the proposal.

By its nature, DS–EE reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in fossil fuel-fired EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, or labor, for example) or other factors such as improved labor productivity and reduced health care expenditures resulting from cleaner air. For these reasons, the numbers reported here should not be interpreted as a net national employment impact.

F. What are the benefits of the proposed action?

Implementing the proposed action will generate benefits by reducing emissions of CO_2 and criteria pollutant precursors, including SO_2, NO_X, and directly emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for this proposal. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. There are many additional benefits which we are not able to quantify, leading to an underestimate of monetized benefits. In summary, we estimate the total combined climate benefits and health co-benefits for the rate-based federal plan approach to be $3.5 to $4.6 billion in 2020, $18 to $28 billion in 2025, and $34 to $54 billion in 2030 (3 percent discount rate, 2011$). Total combined climate benefits and health co-benefits for the mass-based federal plan approach are estimated to be $5.3 to $8.1 billion in 2020, $19 to $29 billion in 2025, and $32 to $48 billion in 2030 (3 percent discount rate, 2011$). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates is provided in Tables 15 through 17 of this preamble.

TABLE 15—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE PROPOSAL

[Billions of 2011$] [a]

Year	Discount rate (statistic)	Monetized climate benefits		
		2020	2025	2030
Rate-based Federal Plan Approach				
CO_2 Reductions (million short tons)		69	232	415
	5 percent (average SC–CO_2)	$0.80	$3.1	$6.4
	3 percent (average SC–CO_2)	2.8	10	20
	2.5 percent (average SC–CO_2)	4.1	15	29
	3 percent (95th percentile SC–CO_2)	8.2	31	61
Mass-based Federal Plan Approach				
CO_2 Reductions (million short tons)		81	265	413
	5 percent (average SC–CO_2)	$0.94	$3.6	$6.4
	3 percent (average SC–CO_2)	3.3	12	20
	2.5 percent (average SC–CO_2)	4.9	17	29
	3 percent (95th percentile SC–CO_2)	9.7	35	60

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SC–CO_2) estimates for the analysis years and are rounded to two significant figures.

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSAL, RATE-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Rate-Based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	14	\$0.44 to \$0.99	\$0.39 to \$0.89
NO_X	50	\$0.14 to \$0.33	\$0.13 to \$0.30
Ozone precursor [c]			
NO_X (ozone season only)	19	\$0.12 to \$0.52	\$0.12 to \$0.52
Total Monetized Health Co-benefits		\$0.70 to \$1.8	\$0.64 to \$1.7
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$3.5 to \$4.6	\$3.5 to \$4.5
Rate-Based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	178	\$6.4 to \$14	\$5.7 to \$13
NO_X	165	\$0.56 to \$1.3	\$0.50 to \$1.1
Ozone precursor [c]			
NO_X (ozone season only)	70	\$0.49 to \$2.1	\$0.49 to \$2.1
Total Monetized Health Co-benefits		\$7.4 to \$18	\$6.7 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$18 to \$28	\$17 to \$26
Rate-Based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	318	\$12 to \$28	\$11 to \$25
NO_X	282	\$1.0 to \$2.3	\$0.93 to \$2.1
Ozone precursor [c]			
NO_X (ozone season only)	118	\$0.86 to \$3.7	\$0.86 to \$3.7
Total Monetized Health Co-benefits		\$14 to \$34	\$13 to \$31
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$34 to \$54	\$33 to \$51

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects, or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous United States.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSAL, MASS-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Mass-Based Federal Plan Approach, 2020			
$PM_{2.5}$ precursors [b]			
SO_2	54	\$1.7 to \$3.8	\$1.5 to \$3.4
NO_X	60	\$0.17 to \$0.39	\$0.16 to \$0.36
Ozone precursor [c]			
NO_X (ozone season only)	23	\$0.14 to \$0.61	\$0.14 to \$0.61
Total Monetized Health Co-benefits		\$2.0 to \$4.8	\$1.8 to \$4.4
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$5.3 to \$8.1	\$5.1 to \$7.7
Mass-Based Federal Plan Approach, 2025			
$PM_{2.5}$ precursors [b]			
SO_2	185	\$6.0 to \$13	\$5.4 to \$12
NO_X	203	\$0.58 to \$1.3	\$0.52 to \$1.2
Ozone precursor [c]			
NO_X (ozone season only)	88	\$0.56 to \$2.4	\$0.56 to \$2.4
Total Monetized Health Co-benefits		\$7.1 to \$17	\$6.5 to \$16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$19 to \$29	\$18 to \$27
Mass-Based Federal Plan Approach, 2030			
$PM_{2.5}$ precursors [b]			
SO_2	280	\$10 to \$23	\$9.0 to \$20
NO_X	278	\$0.87 to \$2.0	\$0.79 to \$1.8
Ozone precursor [c]			
NO_X (ozone season only)	121	\$0.82 to \$3.5	\$0.82 to \$3.5
Total Monetized Health Co-benefits		\$12 to \$28	\$11 to \$26
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		\$32 to \$48	\$31 to \$46

[a] All estimates are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, exposure to mercury, ecosystem effects, or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous United States.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the proposed Clean Power Plan EGs. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). Referred to as the social cost of carbon, each value increases over time. For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of carbon values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SC–CO_2) estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking.[129] We refer to these

[129] Docket ID EPA–HQ–OAR–2013–0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact

Continued

estimates, which were developed by the U.S. government, as ''SC–CO_2 estimates.'' The SC–CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (*i.e.,* benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC–CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC–CO_2 estimates and recommended four global values for use in regulatory analyses. The SC–CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC–CO_2 Technical Support Document (2010 TSD) [130] provides a complete discussion of the methods used to develop these estimates and the current TSD presents and discusses the 2013 update (including two recent minor corrections to the estimates).[131]

OMB's Office of Information and Regulatory Affairs received comments in response to a request for public comment on the approach used to develop the estimates. After careful evaluation of the full range of comments submitted to OMB, the IWG continues to recommend the use of the SC–CO_2 estimates in RIA.[132] With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC–CO_2 estimates continue to reflect the best available scientific and economic information on climate change. The Academies review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC–CO_2 estimates in future updates. See the EPA Response to Comments document for the complete response to comments received on SC–CO_2 as part of this rulemaking.

Concurrent with OMB's publication of the response to comments on SC–CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC–CO_2 estimates are one dollar less than the mean SC–CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The EPA, as a member of the IWG on the SC–CO_2, has carefully examined and evaluated the minor technical corrections in the revised TSD and the public comments submitted to OMB's SC–CO_2 comment process. The EPA concurs with the IWG's conclusion that it is reasonable, and scientifically appropriate, to use the current SC–CO_2 estimates for purposes of RIA, including for this proceeding.

The four SC–CO_2 estimates are as follows: $12, $40, $60, and $120 per short ton of CO_2 emissions in the year 2020 (2011$).[133] The first three values are based on the average SC–CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. The SC–CO_2 value at several discount rates are included because the literature shows that the SC–CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC–CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC–CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

There are limitations in the estimates of the benefits from this proposal, including the omission of climate and other CO_2 related benefits that could not be monetized. The 2010 TSD discusses a number of limitations to the SC–CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important impacts of CO_2 recognized in the literature, such as ocean acidification or potential tipping points, for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. As previously noted, the IWG plans to seek

Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, DOE, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.*

[130] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf.*

[131] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf,* Docket ID EPA–HQ–OAR–2013–0495, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015).

[132] See *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon* for additional details, including the OMB Response to Comments and the SC–CO_2 TSDs.

[133] The current version of the TSD is available at: *https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.* The 2010 and 2013 TSDs present SC–CO_2 in 2007$ per metric ton. The estimates were adjusted to (1) Short tons for using conversion factor 0.90718474 and (2) 2011$ using Gross Domestic Product and Related Price Measures: Indexes and Percent Changes, *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.*

independent expert advice on technical opportunities to improve the SC–CO_2 estimates from the Academies. The Academies' process will help to ensure that the SC–CO_2 estimates used by the federal government continue to reflect the best available science and methodologies. Additional details are provided in the TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions from the federal plan approaches examined in the RIA for this proposal. Unlike the global SC–CO_2 estimates, the air pollution health co-benefits are estimated for the contiguous United States only. We used a ''benefit-per-ton'' approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, we conducted air quality modeling for an illustrative scenario reflecting the proposed Clean Power Plan EGs to convert precursor emissions into changes in ambient $PM_{2.5}$ and ozone concentrations. We then used these air quality modeling results in BenMAP [134] to calculate average regional benefit-per-ton estimates using the health impact assumptions used in the PM NAAQS RIA [135] and Ozone NAAQS RIAs.[136] [137] The three regions were the Eastern United States, Western United States, and California. To calculate the co-benefits for this proposal, we multiplied the regional benefit-per-ton estimates generated from modeling of the proposed Clean Power Plan EGs standards by the corresponding regional emission reductions for this proposal.[138] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions for the proposed Clean Power Plan EGs, which may not exactly match the emission reductions in this proposed rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information regarding the derivation of the benefit-per-ton estimates is available in the Clean Power Plan Final Rule RIA.

PM benefit-per-ton values are generated using two concentration-response functions, Krewski et al. (2009) [139] and Lepeule et al. (2012).[140] These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between $PM_{2.5}$ precursors depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we use two key empirical studies, one based on the American Cancer Society cohort study (Krewski et al., 2009) and one based on the extended Six Cities cohort study (Lepuele et al., 2012). The $PM_{2.5}$ co-benefits results are presented as a range based on benefit-per-ton estimates calculated using the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates using benefit-per-ton estimates based on expert judgments of the effect of $PM_{2.5}$ on premature mortality (Roman et al., 2008) [141] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship.

For the ozone co-benefits, we present the results as a range reflecting benefit-per-ton estimates which use several different concentration-response functions for mortality, with the lower end of the range based on a benefit-per-ton estimate using the function from Bell et al. (2004) [142] and the upper end based on a benefit-per-ton estimate using the function from Levy et al. (2005).[143] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, in estimating the benefits-per-ton for $PM_{2.5}$ precursors, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of the EPA's *Integrated Science Assessment for Particulate Matter,*[144] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies, that documents the association between elevated $PM_{2.5}$ concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations

[134] *http://www.epa.gov/airquality/benmap/index.html.*

[135] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA–452/R–12–003, December 2012). Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/finalria.pdf.*

[136] U.S. Environmental Protection Agency (U.S. EPA). 2008b. Final Ozone NAAQS Regulatory Impact Analysis. Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA–452/R–08–003, March 2008). Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/452_R_08_003.pdf.*

[137] U.S. Environmental Protection Agency (U.S. EPA). 2010. Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods. Available at: *http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf.*

[138] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: *http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf.*

[139] Krewski D.; M. Jerrett; R. T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.

[140] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. ''Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.'' *Environmental Health Perspective,* 120(7), July, pp. 965–970.

[141] Roman, H., et al. 2008. ''Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.'' *Environmental Science & Technology,* Vol. 42, No. 7, February, pp. 2268–2274.

[142] Bell, M.L., et al. 2004. ''Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000.'' *Journal of the American Medical Association,* 292(19), pp. 2372–8.

[143] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. ''Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis.'' *Epidemiology.* 16(4): p. 458–68.

[144] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA–600–R–08–139F, December 2009). Available at: *http://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.*

that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[145] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule that is above the lowest measured $PM_{2.5}$ levels (LML) for the two $PM_{2.5}$ mortality epidemiology studies that form the basis for our analysis. As a surrogate measure of mortality impacts above the LML, we provide the percentage of the population exposed above the LML in each of the two studies, using the estimates of baseline projected $PM_{2.5}$ from the air quality modeling for the proposed guidelines used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 88 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter (μg/m³). Using the Lepeule et al. (2012) study, 46 percent of the population is exposed above the LML of 8 μg/m³. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative analysis of this proposed action under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ NAAQS RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and HAP (*e.g.,* mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, a qualitative assessment of these unquantified benefits is included in the RIA for this proposal. In addition, in the RIA for this proposal, we did not estimate changes in emissions of directly emitted particles. As a result, quantified $PM_{2.5}$ related benefits are underestimated by a relatively small amount. In the RIA for the proposed Clean Power Plan EGs, the benefits from reductions in directly emitted $PM_{2.5}$ were less than 10 percent of total monetized health co-benefits across all scenarios and years.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

IX. Community and Environmental Justice Considerations

In this section we provide an overview of the actions that the agency is taking to help ensure that vulnerable communities are not disproportionately impacted by this rulemaking.

As described in the Executive Summary, climate change is an EJ issue. Low-income communities and communities of color already overburdened with pollution are likely to be disproportionately affected by, and less resilient to, the impacts of climate change. This rulemaking will provide broad benefit to communities across the nation, as its purpose is to reduce GHGs, the most significant driver of climate change. While addressing climate change will provide broad benefits, it is particularly beneficial to low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location) where people are most vulnerable to the impacts of climate change (a more robust discussion of the impacts of climate change on vulnerable communities is provided in the Executive Order 12898 discussion in section X.J of this preamble). While climate change is a global phenomenon, the adverse effects of climate change can be very localized, as impacts such as storms, flooding, and droughts are experienced in individual communities.

Vulnerable communities also often receive more than their fair share of conventional air pollution, with the attendant adverse health impacts.

The changes in electricity generation that will result from this rule will further benefit communities by reducing existing air pollution that directly contributes to adverse localized health effects. These air quality improvements will be achieved through this rule because the EGUs that emit the most GHGs also have the highest emissions of conventional pollutants, such as SO_2, NO_X, fine particles, and HAP. These pollutants are known to contribute to adverse health outcomes, including the development of heart and lung diseases, such as asthma and bronchitis, increased susceptibility to respiratory and cardiac symptoms, greater numbers of emergency room visits and hospital admissions, and premature deaths.[146] The EPA expects that the reductions in utilization of higher-emitting units likely to occur during the implementation of federal plans will produce significant reductions in emissions of conventional pollutants, particularly in those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. These reductions will have beneficial effects on air quality and public health, both locally and regionally. Further, this rulemaking complements other actions already taken by the EPA to reduce conventional pollutant emissions and improve health outcomes for overburdened communities.

By reducing millions of tons of CO_2 emissions that are contributing to global GHG levels and providing strong leadership to encourage meaningful reductions by countries across the globe, this rule is a significant step to address health and economic impacts of climate change that will fall disproportionately on vulnerable communities. By reducing millions of tons of conventional air pollutants, this proposed rule will lead to better air quality and improved health in those communities. In the comment period for the Clean Power Plan, we heard from many commenters who recognize and welcome those benefits.

There are other ways in which the actions that result from this rulemaking may affect overburdened communities in positive or potentially adverse ways and we also heard about these from commenters on the EGs.

While the agency expects overall emission decreases as a result of this rulemaking, we recognize that some EGUs may operate more frequently. To the extent that we project increases in utilization as a result of this rulemaking, we expect these increases to occur generally in lower-emitting NGCC units,

[145] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

[146] Six Common Air Pollutants. *http://www.epa.gov/oaqps001/urbanair/.*

which have minimal or no emissions of SO_2 and HAP, lower emissions of particulate matter, and much lower emissions of NO_X compared to higher-emitting steam units. We acknowledge the concerns that have been raised on this point, but also the difficulty in anticipating prior to plan implementation where those impacts might occur. As described below, the EPA intends to conduct an assessment of whether and where emission increases may result from plan implementation and mitigate adverse impacts, if any, in overburdened communities.

In addition to the many positive anticipated health benefits of this rulemaking, it also will increase the use of clean energy and will encourage EE. These changes in the electricity generation system, which are already occurring, but may be accelerated by this program, are expected to have other positive benefits for communities. The electricity sector is, and will continue to be, investing more in RE and EE. The construction of renewable generation and the implementation of EE programs such as residential weatherization will bring investment and employment opportunities to the communities where they take place. It is important to ensure that all communities share in these benefits. And while we estimate that the benefits of this program will greatly exceed its costs (as noted in the RIA for this rulemaking), it is also important to ensure that to the extent there are increases in electricity costs, that those do not fall disproportionately on those least able to afford them.

The EPA has engaged with community groups throughout this rulemaking and we received many comments on the issues outlined above from community groups, EJ organizations, faith-based organizations, public health organizations, and others. This input has informed this proposed rulemaking and prompted the EPA to consider other steps that the agency can take in the short and long term to consider EJ and impacts to communities in federal plan development and implementation.

It has also prompted us to work with our federal partners to make sure that communities have information on federal resources available to assist them. We describe these resources below, as well as resources that the EPA will be providing to assist communities in accessing EE/RE and financial assistance programs.

Finally, and importantly, we recognize that communities must be able to participate meaningfully in the development of this rulemaking. In this section, we discuss the steps that the EPA will take to assist communities in engaging with the agency throughout the comment period of this rulemaking.

A. Proximity Analysis

The EPA is committed to ensuring that there is no disproportionate, adverse impact on overburdened communities as a result of this proposed rulemaking. To provide information fundamental to beginning that process, the EPA has conducted a proximity analysis for this proposed rulemaking that summarizes demographic data on the communities located near power plants.[147] The EPA understands that, in order to prevent disproportionately high and adverse human health or environmental effects on these communities, both the agency and communities must have information on the communities living near facilities, including demographic data, and that accessing and using census data files requires expertise that some community groups may lack. Therefore, the EPA used census data from the American Community Survey (ACS) 2008–2012 to conduct a proximity analysis that can be used by communities as they engage with the agency throughout the comment period of this rulemaking. The analysis and its results are presented in the EJ Screening Report for the Clean Power Plan, which is located in the docket for this rulemaking at EPA–HQ–OAR–2015–0199.

The proximity analysis provides detailed demographic information on the communities located within a 3-mile radius of each affected power plant in the United States. Included in the analysis is the breakdown by percentage of community characteristics such as income and minority status. The analysis shows a higher percentage of communities of color and low-income communities living near power plants than national averages. It is important to note that the impacts of power plant emissions are not limited to a 3-mile radius and the impacts of both potential increases and decreases in power plant emissions can be felt many miles away. Still, being aware of the characteristics of communities closest to power plants is a starting point in understanding how changes in the plant's air emissions may affect the air quality experienced by some of those already experiencing environmental burdens.

Although overall there is a higher fraction of communities of color and low-income populations living near power plants than national averages, there are differences between rural and urban power plants. There are many rural power plants that are located near small communities with high percentages of low-income populations and lower percentages of communities of color. In urban areas, nearby communities tend to be both low-income communities and communities of color. In light of this difference between rural and urban communities proximate to power plants and in order to adequately capture both the low-income and minority aspects central to environmental justice (EJ) considerations, we use the terms ''vulnerable'' or ''overburdened'' when referring to these communities. Our intent is for these terms to be understood in an expansive sense, in order to capture the full scope of communities, including indigenous communities most often located in rural areas, that are central to our EJ and community considerations.

As stated in the Executive Order 12898 discussion located in section X.J of this preamble, the EPA believes that all communities will benefit from this proposed rulemaking because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired power plants. The EPA also believes that the information provided in the proximity analysis will promote engagement between vulnerable communities and the agency throughout the rulemaking process. In addition to providing the proximity analysis in the docket of this rulemaking, the EPA will make it publicly available on its Clean Power Plan Communities Portal that will be linked to this rulemaking's Web site (*http://www.epa.gov/cleanpowerplan*). Furthermore, the EPA has also created an interactive mapping tool that illustrates where power plants are located and provides information on a state level. This tool is available at: *http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/*.

B. Community Engagement in This Rulemaking Process

The EPA has heard from vulnerable communities throughout the outreach process for the Clean Power Plan that it is imperative for communities to have an understanding of how rulemakings that target climate change work. They expressed a desire to know how these programs may benefit their communities and what the potential adverse impacts of the rules may be on their communities. We intend to provide

[147] The proximity analysis was conducted using the EPA's environmental justice mapping and screening tool, EJSCREEN.

communities with the information that they need to engage with the agency throughout the comment period.

We have received feedback from communities that public hearings, webinars, and in-person meetings are the most effective ways to engage with them and to provide them with the information they need to understand the rulemaking process. Therefore, for this rulemaking, in addition to conducting public hearings for all members of the American public, the agency will hold a national webinar for communities in the early stages of the comment period. The goal of this webinar will be to walk communities through the highlights of the preamble, so they have an understanding of how the rulemaking may potentially affect their communities and they will have the contextual information they need to actively engage with the agency throughout the comment period.

Additionally, because we received positive feedback on the effectiveness of the face-to-face meetings conducted on the regional level, each region will be offering an outreach meeting(s) for communities. The goal of these meetings is to build a level of understanding on this rulemaking to enable vulnerable communities to actively engage with the agency throughout the comment period. Furthermore, we will follow up on common issues raised during the outreach meetings with national conference calls, specifically targeted for vulnerable communities.

C. Providing Communities With Access to Additional Resources

In section V.D of this preamble, we outline that we are seeking comment on whether a portion of this set-aside should be targeted to RE projects that benefit low-income communities. Furthermore, the EPA is seeking comment on how a low-income community should be defined as eligible under this set-aside. We also seek comment on how much of the set-aside should be designated as targeted at over-burdened communities. We also request comment on whether the methods of approval and distribution of allowances to projects that benefit low-income communities should differ, and if so, in what manner, from the methods that are proposed to apply to other RE projects.

As discussed below, there are also many federal programs that can help low-income populations access the benefits of RE and EE, and the economic benefits of a cleaner energy economy.

In the coming months, the EPA will continue to provide information and resources for low-income communities on existing federal, state, local, and other financial assistance programs to encourage EE/RE opportunities that are already available to communities. For example, the EPA will provide a catalog of current or recent state and local programs that have successfully helped communities adopt EE/RE measures. The goal of these resources is to help vulnerable communities gain the benefits of this rulemaking. The use of these RE/EE tools can also help low-income households reduce their electricity consumption and bills.

Additionally, as part of the resources that we will be providing low-income communities, the EPA will provide information on the Administration's Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) Initative and other programs that specifically target economic development assistance to communities affected by changes in the coal industry and the utility power sector.[148]

D. Federal Programs and Resources Available to Communities

Federal agencies have a history of bringing EE and RE to low-income communities. Earlier this summer, the Administration announced a new initiative to scale up access to solar energy and cut energy bills for all Americans, in particular low- and moderate-income communities, and to create a more inclusive solar workforce. As part of this new initiative, the U.S. DOE, the U.S. Department of Housing and Urban Development, U.S. Department of Agriculture, and the EPA launched a National Community Solar Partnership to unlock access to solar energy for the nearly 50 percent of households and businesses that are renters or do not have adequate roof space to install solar systems, with a focus on low- and moderate-income communities. The Administration also set a goal to install 300 MW of RE in federally subsidized housing by 2020 and plants to provide technical assistance to make it easier to install solar energy on affordable housing, including clarifying how to use federal funding for EE and RE. To continue enhancing employment opportunities in the solar industry for all Americans, AmeriCorps is providing funding to deploy solar energy and create jobs in underserved communities, and DOE is working to expand solar energy education and opportunities for job training.

These recent announcements build on the many existing federal programs and resources available to improve EE and accelerate the deployment of RE in vulnerable communities. Some examples of these resources include: The DOE's Weatherization Assistance Program, Health and Human Service's Low-Income Home Energy Assistance Program, the Department of Agriculture's Energy Efficiency and Conservation Loan Program, High Cost Energy Grant Program, and the Rural Housing Service's Multi-Family Housing Program.

The U.S. Department of Housing and Urban Development supports EE improvements and the deployment of RE on affordable housing through its Energy Efficient Mortgage Program, Multifamily Property Assessed Clean Energy Pilot with the State of California, PowerSaver Program, and the use of Section 108 Community Development Block Grants. The Department of Treasury provides several tax credits to support RE development and EE in low-income communities, including the New Markets Tax Credit Program and the Low-Income Housing Tax Credit. The EPA's RE-Powering America's Land Initiative promotes the reuse of potentially contaminated lands, landfills and mine sites—many of which are in low-income communities—for RE through a combination of tailored redevelopment tools for communities and developers, as well as site-specific technical support. The EPA's Green Power Partnership is increasing community use of renewable electricity across the country and in low-income communities. The EPA partners with EE programs throughout the country that leverage ENERGY STAR to deliver broad consumer energy-saving benefits, of particular value to low-income households who can least afford high energy bills. ENERGY STAR also works with houses of worship to reduce energy costs—savings that can then be repurposed to their community mission, including programs and assistance to residents in low-income communities. The EPA will be working with these federal partners and others to ensure that states and vulnerable communities have access to information on these programs and their resources.

The federal government also has a number of programs to expand employment opportunities in the energy sector, including for underserved populations. Examples of these include the U.S. Department of Housing and Urban Development, DOE, and the Department of Education's ''STEM, Energy, and Economic Development'' program; DOE's Diversity in Science and Technology Advances National Clean Energy in Solar (DISTANCE-

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

Solar) Program; Grid Engineering for Accelerated Renewable Energy Deployment (GEARED); the DOL's Trade Adjustment Assistance Community College and Career Training (TAACCCT), Apprenticeship USA Advancing Apprenticeships in the Energy Field, Job Corps Green Training and Greening of Centers, and YouthBuild; and the EPA's Environmental Workforce Development and Job Training (EWDJT) program.

E. Assessing Impacts of Federal Plan Implementation

It is important to the EPA that the implementation of federal plans be assessed in order to identify whether they cause any adverse impacts on communities already overburdened by disproportionate environmental harms and risks. The EPA will conduct its own assessment during the implementation phase of this rulemaking to determine whether the implementation of federal plans and other air quality rules are, in fact, reducing emissions and improving air quality in all areas and, or whether there are localized air quality impacts that need to be addressed under the Clean other CAA authorities.

The EPA will provide trainings for communities on resources that they can use to assess localized impacts, especially effects of co-pollutants, of plans on their communities. This training will include guidance in accessing the publicly available information that sources and states currently report that can help with ongoing assessments of federal plan impacts. For example, unit-specific emissions data and air quality monitoring data are readily available. This information, together with the assessment that the EPA will conduct in the implementation phase of this rulemaking will enable the agency and communities to monitor any disproportionate emissions that may result in adverse impacts and address them.

F. Co-Pollutants

Air quality in a given area is affected by emissions from nearby sources and may be influenced by emissions that travel hundreds of miles and mix with emissions from other sources.[149] In the CSAPR the EPA used its authority to reduce emissions that significantly contribute to downwind exposures. The RIA for the final CSAPR anticipates substantial health benefits for the population across a wide region. Similarly, the EPA believes that, like the CSAPR, this rulemaking will result in significant health benefits because it will reduce co-pollutant emissions of SO_2 and NO_X on a regional and national basis.[150] Thus, localized increases in NO_X emissions may well be more than offset by NO_X decreases elsewhere in the region that produce a net improvement in ozone and particulate concentrations across the area.

Another effect of the final CO_2 emission standards for affected existing fossil fuel-fired EGUs may be increased utilization of other, unmodified EGUs—in particular, high efficiency gas-fired EGUs—with relatively low GHG emissions per unit of electrical output. These plants may operate more hours during the year and could emit pollutants, including pollutants whose environmental effects would be localized and regional rather than global as is the case with GHG emissions. Changes in utilization already occur in response to energy demands and evolving energy sources, but the final CO_2 emission standards for affected existing fossil fuel-fired EGUs can be expected to cause more such changes. Increased utilization of solid fossil fuel-fired units generally would not increase peak concentrations of $PM_{2.5}$, NO_X, or ozone around such EGUs to levels higher than those that are already occurring because peak hourly or daily emissions generally would not change; however, increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources likely to be dispatched more frequently have very low emissions of primary PM, SO_2, and HAP per unit of electrical output and that they must continue to comply with other CAA requirements that directly address the conventional pollutants, including federal emission standards, rules included in SIPs, and conditions in title V operating permits, in addition to the guidelines in the final EGs rulemaking published elsewhere in this **Federal Register**. Therefore, local (or regional) air quality for these pollutants is not likely to be significantly affected. For natural gas-fired EGUs, the EPA found that regulation of HAP emissions ''is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.'' [151] Because gas-fired EGUs emit essentially no mercury, increased utilization will not increase methyl mercury concentrations in water bodies near these affected EGUs. In studies done by DOE/NETL comparing cost and performance of coal- and NGCC-fired generation, they assumed SO_2, NO_X, PM (and Hg) emissions to be ''negligible.'' Their studies predict NO_X emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler.[152] Many, although not all, NGCC units are also very well controlled for emissions of NO_X through the application of after combustion controls such as selective catalytic reduction.

G. The EPA's Continued Engagement

The EPA is committed to helping ensure that this action will not have disproportionate adverse human health or environmental effects on vulnerable communities. Throughout the implementation phase of this rulemaking, the agency will continue to provide trainings and resources to assist communities and as they engage with the agency. The EPA, through its outreach efforts during the comment period, will continue to solicit feedback from communities on what they would like additional trainings and resources on.

As described above, the EPA will assess the impacts of this rulemaking during its implementation. The EPA will house this assessment, along with the proximity analysis and other information generated throughout the implementation process, on its Clean Power Plan Communities Portal that will be linked to this rulemaking's Web site (*http://www.epa.gov/cleanpowerplan*). In addition, the EPA has expanded its set of resources that are being developed to help communities understand the breadth of policy options and programs that have successfully brought EE/RE to low-income communities. The EPA is committed to continuing its engagement with communities from the comment period of this rulemaking through federal plan implementation.

The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when crafting this rulemaking.[153] A more detailed discussion concerning the application of Executive Order 12898 in this rulemaking can be found in section X.J of this preamble. A summary of the EPA's interactions with communities is

[149] 76 FR 48348, August 11, 2011.

[150] *See* 76 FR 48347, August 11, 2011.

[151] 65 FR 79831, December 20, 2000.

[152] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a, September 2013 Revision 2, November 2010 DOE/NETL–2010/1397.

[153] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

in the EJ Screening Report for the Clean Power Plan, available in the docket of this rulemaking. Furthermore, the EPA's responses to public comments, including comments received from communities, are provided in the response to comments documents located in the docket for this rulemaking.

In summary, the EPA in this proposed rulemaking has designed an integrative approach that helps to ensure that vulnerable communities are not disproportionately impacted by this rule. The proximity analysis that the agency has conducted is a central component of this approach. Not only is the proximity analysis a useful tool to help identify communities that may be impacted by this rulemaking; it will also help communities as they engage with the EPA throughout the comment period. It will help the EPA as we help low-income communities access EE/RE and financial assistance programs. Finally, in order to continue to ensure that overburdened communities are not disproportionately impacted by this rule, the EPA will be conducting an assessment during the implementation phase of the effects of this and other rules on air quality.

X. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket for this rulemaking. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Proposed Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations'' (EPA–452/R–15–006, July 2015), is available in the docket and is briefly summarized in section VIII of this preamble.

Consistent with Executive Order 12866 and Executive Order 13563, the EPA estimated the costs and benefits for two alternative federal plan approaches to implementing the proposed federal plan and model trading rules. The proposed action will achieve the same levels of emissions performance as required of state plans under the CAA section 111(d) EGs for the control of CO_2. Actions taken to comply with the guidelines will also reduce the emissions of directly-emitted $PM_{2.5}$, SO_2, and NO_X. The benefits associated with these $PM_{2.5}$, SO_2, and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The RIA for this proposal analyzed two implementation scenarios, which we term the ''rate-based federal plan approach'' and the ''mass-based federal plan approach.'' It is very important to note that the differences between the analytical results for the rate-based and mass-based federal plan approaches presented in the RIA may not be indicative of likely differences between the approaches. In other words, if one approach performs differently than the other on a given metric during a given time period, this does not imply this will apply in all instances.

It is important to note that the potential regulatory impacts presented in the Clean Power Plan Final Rule RIA and the RIA for this proposed rule are not additive. Both RIAs present estimates of the benefits and costs of achieving the emission performance rates of the Clean Power Plan EGs. In the case of the Clean Power Plan Final Rule RIA, the illustrative analysis assumes the performance rates are met under state plans. In the case of this RIA for the proposed federal plan and model trading rules, the same performance rates are accomplished but are assumed to be achieved under the federal plan or model trading rules.

The EPA has used the social cost of carbon estimates presented in the *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015)* (''current TSD'') to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as ''SC–CO_2 estimates.'' The SC–CO_2 is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SC–CO_2 estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SC–CO_2 value deemed to be central in the current TSD: The model average at 3 percent discount rate.

The EPA estimates that, in 2020, this proposal will yield monetized climate benefits (in 2011$) of approximately $2.8 billion for the rate-based approach and $3.3 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2020 are estimated to be $0.7 billion to $1.8 billion (2011$) for a 3 percent discount rate and $0.64 billion to $1.7 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2020 are estimated to be $2.0 billion to $4.8 billion (2011$) for a 3 percent discount rate and $1.8 billion to $4.4 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and monitoring, reporting, and recordkeeping costs in 2020, are approximately $2.5 billion for the rate-based approach and $1.4 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to range from $1.0 billion to $2.1 billion (2011$) for the rate-based approach and from $3.9 billion to $6.7 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2025, the proposal will yield monetized climate benefits (in 2011$) of approximately $10 billion for the rate-based approach and $12 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.4 billion to $18 billion (2011$) for a 3 percent discount rate and $6.7 billion to $16 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2025 are estimated to be $7.1 billion to $17 billion (2011$) for a 3 percent discount rate and $6.5 billion to $16 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and MRR costs in 2025, are approximately $1.0 billion for the rate-based approach and $3.0 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2025 are estimated to range from $17 billion to $27 billion (2011$) for the rate-based approach and $16 billion to $26 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

The EPA estimates that, in 2030, the proposal will yield monetized climate benefits (in 2011$) of approximately $20 billion for the rate-based approach and $20 billion for the mass-based approach (3 percent model average). For the rate-based approach, the air pollution health co-benefits in 2030 are estimated to be $14 billion to $34 billion (2011$) for a 3 percent discount rate and $13 billion to $31 billion (2011$) for a 7 percent discount rate. For the mass-based approach, the air pollution health co-benefits in 2030 are estimated to be $12 billion to $28 billion (2011$) for a 3 percent discount rate and $11 billion to $26 billion (2011$) for a 7 percent discount rate. The annual compliance costs estimated by IPM and inclusive of DS–EE program and participant costs and monitoring, reporting, and recordkeeping costs in 2030, are approximately $8.4 billion for the rate-based approach and $5.1 billion for the mass-based approach (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2030 are estimated to range from $26 billion to $45 billion (2011$) for the rate-based approach and from $26 billion to $43 billion (2011$) for the mass-based approach, using a 3 percent discount rate (model average).

Table 18 and Table 19 of this preamble provide the estimates of the climate benefits, health co-benefits, compliance costs and net benefits of the proposal for rate-based and mass-based federal plan approaches, respectively.

TABLE 18—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSAL IN 2020, 2025 AND 2030 UNDER THE RATE-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

	Rate-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.80		$3.1		$6.4	
3% discount rate	$2.8		$10		$20	
2.5% discount rate	$4.1		$15		$29	
95th percentile at 3% discount rate	$8.2		$31		$61	
Air Quality Co-Benefits Discount Rate						
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$0.70 to $1.8	$0.64 to $1.7	$7.4 to $18	$6.7 to $16	$14 to $34	$13 to $31
Compliance Costs [d]	$2.5		$1.0		$8.4	
Net Benefits [e]	$1.0 to $2.1	$1.0 to $2.0	$17 to $27	$16 to $25	$26 to $45	$25 to $43
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility impairment.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC–CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using the IPM for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS–EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSAL IN 2020, 2025 AND 2030 UNDER THE MASS-BASED FEDERAL PLAN APPROACH

[Billions of 2011$] [a]

	Mass-Based Approach					
	2020		2025		2030	
Climate Benefits [b]						
5% discount rate	$0.9		$3.6		$6.4	
3% discount rate	$3.3		$12		$20	
2.5% discount rate	$4.9		$17		$29	
95th percentile at 3% discount rate	$9.7		$35		$60	
Air Quality Co-Benefits Discount Rate						
	3%	7%	3%	7%	3%	7%
Air Quality Health Co-benefits [c]	$2.0 to $4.8	$1.8 to $4.4	$7.1 to $17	$6.5 to $16	$12 to $28	$11 to $26
Compliance Costs [d]	$1.4		$3.0		$5.1	
Net Benefits [e]	$3.9 to $6.7	$3.7 to $6.3	$16 to $26	$15 to $24	$26 to $43	$25 to $40
Non-Monetized Benefits	Non-monetized climate benefits. Reductions in exposure to ambient NO_2 and SO_2. Reductions in mercury deposition. Ecosystem benefits associated with reductions in emissions of NO_X, SO_2, PM, and mercury. Visibility improvement.					

[a] All are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SC–CO_2 than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SC–CO_2 estimated for a 3 percent discount rate. However, we emphasize the importance and value of considering the full range of SC–CO_2 values. As shown in the RIA, climate benefits are also estimated using the other three SC–CO_2 estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SC–CO_2 estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of SO_2 and NO_X. The co-benefits do not include the benefits of reductions in directly emitted $PM_{2.5}$. These additional benefits would increase overall benefits by a few percent based on the analyses conducted for the Clean Power Plan proposed rule. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 98 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Costs are approximated by the compliance costs estimated using IPM for this proposal and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and DS–EE program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SC–CO_2 at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on additional discount rates.

There are additional important benefits that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 GHGs (*e.g.,* nitrous oxide and methane) and co-benefits from reducing direct exposure to SO_2, NO_X, and HAP (*e.g.,* mercury), as well as from reducing ecosystem effects and visibility impairment. Based upon the foregoing discussion, it remains clear that the benefits of this proposed action are substantial, and far exceed the costs. Additional details on benefits, costs, and net benefits estimates are provided in the RIA for this proposal.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number *2526.01.* You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until approved by OMB.

This rule does not directly impose specific requirements on state and U.S. territory governments with affected EGUs. The rule also does not impose specific requirements on tribal governments that have affected EGUs located in their area of Indian country. This rule does impose specific requirements on affected EGUs located in states, U.S. territories, or areas of Indian country.

The information collection activities in this proposed rule are consistent with those activities defined under the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (*i.e.,* the Clean Power Plan) finalized on August 3, 2015. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR number 2526.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

Aside from reading and understanding the rule, this proposed action would impose minimal new information collection burden on affected EGUs beyond what those affected EGUs would already be subject to under the authorities of 40 CFR parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

Although the EPA cannot determine at this time how many affected EGU respondents will submit information under the federal plan, the EPA has estimated an ''upper bound'' burden estimate for this ICR that estimates burden should every affected EGU read and understand the rule. This is the only potential respondent activity that would be required under the 3-year period following publication of the final federal plan, as there are no obligations to respond in this period. The results of this upper bound estimate of federal plan burden are presented below:

Respondents/affected entities: 1,028.

Respondents' obligation to respond: Not applicable, no responses are required during the period covered by the ICR.

Estimated number of respondents: Unknown at this time, but have assumed all affected entities are respondents for an upper bound estimate.

Frequency of response: None, no responses are required during the period covered by the ICR.

Total estimated burden: 17,133 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1,706,501 (per year).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *oria_submissions@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than November 23, 2015. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review within the RIA in docket EPA–HQ–OAR–2015–0199 and is summarized here.

The small entities subject to the requirements of this proposed rule may include privately-owned and publicly-owned entities, and rural electric cooperatives that are majority owners of affected EGUs. The EPA conducted this regulatory flexibility analysis at the highest level of ownership, evaluating parent entities with the largest share of ownership in at least one potentially-affected EGU included in EPA's Base Case using the IPM v.5.15, used in the RIA for this proposed rule. This analysis drew on parsed unit-level estimates using IPM results for 2030.

The EPA identified 223 potentially affected EGUs owned by 74 small entities included in 2030 projections from EPA's IPM v.5.15. Fifty-nine of these potentially affected EGUs are projected to no longer be operating by 2030 in the Base Case of EPA's version of IPM. Twenty-four small entities are projected to have all of their potentially affected EGUs cease operation by 2030 in this base case.

The EPA estimated net compliance costs for individual EGUs for the proposed rule using components for operating and annualized capital costs, fuel costs, demand-side energy efficiency program costs, and revenue changes. This approach is consistent with previous proposed power sector regulations, but also adds the additional component of change in demand-side energy efficiency program costs. Investment in demand-side energy efficiency results in lower electricity demand, and consequently fewer emissions as production is reduced to meet the lower demand, an important emission-reduction strategy modeled in the rate-based and mass-based federal plan approaches. For this analysis, the EPA used the parsed unit-level estimates to estimate three of the four components of the net compliance cost equation using IPM outputs: The change in operating and annualized capital costs, the change in fuel costs, and the change in revenue, where all changes are estimated as the difference between the base case and federal plan scenario. These impacts were then summed for each small entity, adjusting for ownership share. An additional analysis was performed outside of EPA's IPM model to estimate the change in demand-side energy efficiency program costs, based largely on IPM-projected outputs.

As noted earlier, there are 74 small entities with potentially affected EGUs that are modeled in the IPM base case in 2030. Of these, 24 small entities are projected to withdraw all of their potentially affected EGUs from operation under base case conditions. This leaves 50 small entities with potentially affected EGUs that are projected to be generating electricity in 2030. Under the rate-based federal plan approach, 7 of these 50 small entities are projected to withdraw all of their potentially affected EGUs from operation by 2030. Under the mass-based federal plan approach, 5 of these 50 small entities are projected withdraw all of their potentially affected EGUs from operation by 2030.

Under the rate-based federal plan approach, 23 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 9 entities are estimated to have net compliance cost savings greater than 3 percent of their generation revenues from affected EGUs. Under the mass-based federal plan approach, 21 small entities are projected to incur net compliance costs greater than 3 percent of generation revenues from their potentially affected EGUs. In contrast, 11 entities are estimated to have net compliance cost savings greater than 3 percent of generation revenues from their affected EGUs.

There are uncertainties and limitations in this analysis that may result in estimates that diverge from what we might see in reality. For example, at the time of this proposal, the EPA has no information on whether any or how many states will require a federal plan. The rate-based and mass-based federal plan approaches analyzed in this IRFA are based on a scenario where all states of the contiguous United States will be regulated under a federal plan. Another factor to consider is that entities operating in regulated or cost-of-service markets are likely able to recover compliance costs through rate adjustments; as a result these costs can be viewed as likely being over-estimates for this set of utilities. Other uncertainties and data limitations exist and are described in the complete IRFA available for review within the RIA for this proposal.

As discussed earlier in this preamble, the reporting, recordkeeping and other compliance requirements are most likely covered under 40 CFR part 75 and part 98 programs for affected EGUs. Therefore, only a marginal additional cost is expected for the monitoring, reporting and recordkeeping requirements of the proposed federal plan for affected EGUs.

Owners of affected EGUs may be subject to other related rules. For example, on September 20, 2013, the EPA proposed carbon pollution standards for new fossil fuel fired EGUs. On June 2, 2014, the EPA proposed carbon pollution standards for modified and reconstructed fossil fuel-fired EGUs, in addition to the Clean Power Plan EGs, to cut carbon pollution from existing fossil fuel-fired EGUs. These existing EGUs are, or will be, potentially impacted by several other recently finalized EPA rules. On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S.C. 1326(b)). This rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. On June 18, 2014 (79 FR 34830), the EPA promulgated the stream electric effluent limitation guidelines (SE ELG) rule to strengthen the controls on discharges from certain steam electric power plants. On April 17, 2015 (80 FR 21302), the EPA promulgated the coal combustion residuals (CCR) rule, which establishes technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

The EPA also considered whether the separate changes that we are proposing to make, as explained in section VII of this preamble, to the framework regulations in subpart B of part 60 of the CAA regulations would have any impacts on small entities. Since these changes only modify and enhance the procedures that the Administrator will follow in processing state plans and promulgating a federal plan, and do not alter the rules or requirements that states or regulated entities must follow, the agency does not believe that there will be economic impacts on small entities from this portion of this proposal. After considering the economic impacts of the proposed changes to 40 CFR 60.27, I certify those changes will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that could potentially result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. This federal plan will apply only to those affected EGUs located in states that do not submit approvable state plans, which is a subset of the EGUs considered in the RIA for the final EGs (see RIA for this proposal for further discussion of impacts). Because it is impossible to determine at this time which states might be ultimately subject to a federal plan, the EPA cannot determine whether this rule, when finalized, will be subject to UMRA. However, as noted below, the agency has done substantial outreach to government entities as part of both the federal plan and the related CAA section 111(d) rulemaking. Further, regardless of whether the EPA does determine that this action ultimately meets the UMRA threshold, the agency intends to do additional outreach with government entities between now and the final rule. Additionally, the EPA has determined that this action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (*e.g.,* municipal and rural electric cooperatives). In light of this interest, prior to this action, the EPA sought early input from representatives of small entities while formulating the provisions of the proposed regulation. Such outreach is also consistent with the President's January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This outreach process has enabled the EPA to hear directly from these representatives, as the EPA developed the rule about how the EPA should approach the complex question of how to apply section 111 of the CAA to the regulation of GHGs from these source categories. We invite comments on all aspects of this proposal and its impacts, including potential adverse impacts, on small entities.

E. Executive Order 13132: Federalism

The EPA believes that this proposed rule may be of significant interest to state and local governments due to its relationship with the Clean Power Plan EGs. Therefore, the EPA has determined that consultations with state and local governments conducted during the Clean Power Plan EGs development process are also relevant to this proposed rule. Consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA consulted with state and local officials early in the process of developing the Clean Power Plan EGs to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501; January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. A detailed Federalism Summary Impact Statement (FSIS) describing the most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final Clean Power Plan EGs, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This proposed action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The EGUs potentially impacted by this proposed rulemaking located on Indian reservations are primarily owned by private entities, and in one case, partially owned by an agency of the U.S. government. As a result, the tribes on whose areas of Indian country those units are located will not be directly impacted by any costs of complying with this proposed rulemaking incurred by the owners/operators of those units. There would only be tribal implications in regards to compliance costs associated with this proposed rulemaking in the case where a tribal government has an ownership interest in a potentially affected EGU. A tribal government could also incur costs in the event that it seeks and is given delegated authority to enforce the federal plan proposed in this rulemaking. The EPA has, nevertheless, offered consultation to the tribes on whose areas of Indian country the units are located. As part of its general outreach to tribes regarding this proposed rulemaking, the EPA received feedback from a number of tribes regarding the potential overall economic impact that both the proposed Clean Power Plan and a proposed federal plan rulemaking may have on them. In these instances, the EPA has reached out to these tribes and as part of the consultation on the Clean Power Plan engaged with them on their concerns regarding a potential federal plan.

The EPA has conducted consultation with tribes on the Clean Power Plan and the Supplemental Proposal for the Clean Power Plan and will offer all tribes consultation on this proposed action. The EPA held consultations with tribes on the Clean Power Plan in the fall of 2014 before the agency issued its Supplemental Proposal for Indian country and U.S. Territories. Additionally, the EPA held consultations for tribes shortly following the release of the supplemental proposal. The agency also held a public hearing on the supplemental proposal on November 19, 2014, in Phoenix, Arizona. At the public hearing the agency received oral comments from community members representing a number of tribes and a number of tribal officials. The agency also conducted consultations with tribes in the spring and summer of 2015. An overview of the consultations provided as part of the Clean Power Plan is available in section XII.F of the final EGs.

Additionally, the EPA engaged in meaningful dialogue with tribal stakeholders to obtain their feedback in the pre-proposal stages of this rulemaking. We provided an update on this proposed rulemaking on the May 28, 2015, National Tribal Air Association and the EPA Air Policy call. Staff attended the National Tribal Forum conference on May 20, 2015 and provided an overview of the Clean Power Plan and explained that the agency would be proposing a federal plan.

Consistent with previous rulemakings impacting the power sector, there is significant tribal interest in these rulemakings because of the potential indirect impacts that rules such as the Clean Power Plan and this proposed federal plan may have on tribes. The EPA specifically solicits additional feedback from tribal officials on all aspects of this proposed rulemaking, including whether tribes whose areas of Indian country contain affected EGU(s) are interested in developing their own plan implementing the final EGs. Additionally, tribal stakeholders will be included in the outreach that the agency will be conducting with those communities already overburdened by pollution, which are often low-income communities, communities of color, and indigenous communities. The actions that the agency will be taking are outlined in section IX of this preamble.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885; April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed federal plan, as well as substantial ozone and $PM_{2.5}$ emission reductions as a cobenefit, would further improve children's health.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for this action as follows. We estimate a 1 to 2 percent change in retail electricity prices on average across the contiguous United States in 2025, and a 22 to 23 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will increase by up to 2.5 percent in 2030. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This proposed action involves technical standards. The EPA proposes to recognize ANSI accreditation under ISO 14065 for GHG validation and verification bodies as a component of accreditation of independent verifiers under both proposed federal plan approachs. The EPA also proposes that net energy output measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority populations and low-income populations, finding that certain parts of the population may be especially vulnerable based on their characteristics or circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See sections X.F and X.G of this preamble, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council of the National Academies that the potential impacts of climate change raise EJ issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions that depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority populations and low-income populations in the United States.[154] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provide new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income populations and some communities of color (in particular, populations defined jointly by ethnic/racial characteristics and geographic location), raising EJ concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, well-being, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and as the 2009 Endangerment Finding illustrates, low-income populations and some communities of color are especially vulnerable to the health and other adverse impacts of climate change. The EPA believes that communities will benefit from this proposed federal plan because this action directly addresses the impacts of climate change by limiting GHG emissions through the establishment of CO_2 emission standards for existing affected fossil fuel-fired EGUs.

In addition to reducing CO_2 emissions, the guidelines finalized in this rulemaking would reduce other emissions from affected EGUs that reduce generation due to higher adoption of EE and RE. These emission reductions will include SO_2 and NO_X, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and HAP, such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[155] the EPA identified low-income populations as being a vulnerable population for experiencing adverse health effects related to PM exposures. Low-income populations have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's susceptibility to PM-related effects.[156] In areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, low-income populations will also benefit from such emission reductions. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

Additionally, as outlined in the community and EJ considerations section IX of this preamble, the EPA has taken a number of actions to help ensure that this action will not have potential disproportionately high and adverse human health or environmental effects on vulnerable communities. The EPA consulted its May 2015, *Guidance on Considering Environmental Justice During the Development of Regulatory Actions,* when determining what actions to take.[157] As described in section IX of this preamble (community and EJ considerations), the EPA also conducted a proximity analysis, which is available in the docket of this rulemaking and is discussed in section IX of this preamble. Additionally, as outlined in sections I and IX of this preamble the EPA has

[154] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

[155] ''National Ambient Air Quality Standards for Particulate Matter, Final Rule,'' 78 FR 3086 (January 15, 2013).

[156] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at *http://www.cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=216546.*

[157] Guidance on Considering Environmental Justice During the Development of Regulatory Actions. *http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.* May 2015.

engaged meaningfully with communities throughout the development of the Clean Power Plan and has devised a robust outreach strategy for continual engagement throughout this rulemaking.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations.

40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 62, and 78 of the Code of the Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Section 60.27 is amended by:

■ a. Revising paragraphs (b), (c) introductory text, and (c)(1);

■ b. Removing and reserving paragraph (c)(2);

■ c. Revising paragraphs (c)(3), (d), and (e)(1); and

■ d. Adding paragraphs (g) through (k).

The revisions and additions read as follows:

§ 60.27 Actions by the Administrator.

* * * * *

(b) After receipt of a complete plan or complete plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator shall, within 12 months after the date on which the submission of a complete plan or complete plan revision is received, approve or disapprove such plan or revision, or each portion thereof.

(c) The Administrator shall promulgate a federal plan within 12 months after the date the Administrator:

(1) Finds the State failed to submit a complete plan or complete plan revision within the time prescribed; or

* * * * *

(3) Disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart and the applicable emission guidelines have not been met.

(d) The Administrator will promulgate the regulations under paragraph (c) of this section for all or a portion of a federal plan, with such modifications as may be appropriate, unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator approves. After the promulgation of a federal plan, the Administrator may approve a State plan or plan revision or portion thereof and withdraw all or a portion of the federal plan.

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

* * * * *

(g) *Completeness criteria*—(1) *General.* Within 60 days of the Administrator's receipt of a state submission, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria for completeness have been met. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA by the date 6 months after receipt of the submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph (g), the State will be treated as not having made the submission.

(2) *Administrative criteria.* In order to be complete, a State plan must contain each of the following administrative criteria:

(i) A formal letter of submittal from the Governor or her designee requesting EPA approval of the plan or revision thereof;

(ii) Evidence that the State has adopted the plan in the state code or body of regulations. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date;

(iii) Evidence that the State has the necessary legal authority under state law to adopt and implement the plan;

(iv) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan. The submittal must be a copy of the official state regulation or document signed, stamped and dated by the appropriate state official indicating that it is fully enforceable by the State. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The State's electronic copy must be an exact duplicate of the hard copy. For revisions to the approved plan, the submittal must indicate the changes made (for example, by redline/strikethrough) to the approved plan;

(v) Evidence that the State followed all of the procedural requirements of the state's laws and constitution in conducting and completing the adoption and issuance of the plan;

(vi) Evidence that public notice was given of the proposed change with procedures consistent with the requirements of § 60.23, including the date of publication of such notice;

(vii) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in § 60.23;

(viii) Compilation of public comments and the State's response thereto; and

(ix) Such other criteria for completeness as may be specified by the Administrator under the applicable emission guidelines.

(3) *Technical criteria.* In order to be complete, a State plan must contain each of the following technical criteria:

(i) Description of the plan approach and geographic scope;

(ii) Identification of each affected source, identification of emission standards for the affected sources, and monitoring, recordkeeping and reporting requirements that will determine compliance by each affected source;

(iii) Identification of compliance schedules and/or increments of progress;

(iv) Demonstration that the State plan submittal is projected to achieve emissions performance under the applicable emission guidelines;

(v) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and

(vi) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.

(4) *Parallel processing.* A State may submit a State plan prior to actual adoption by the State in order to expedite review and provide an opportunity for the State to consider EPA comments prior to submission of a final plan for final review and action. Under these circumstances, the following exceptions to the criteria in this paragraph apply to plans submitted explicitly for parallel processing:

(i) The letter required by paragraph (g)(2)(i) of this section must request that EPA propose approval of the proposed plan by parallel processing;

(ii) In lieu of paragraph (g)(2)(ii) of this section the State must submit a schedule for final adoption or issuance of the plan;

(iii) In lieu of paragraph (g)(2)(iv) of this section the plan must include a copy of the proposed/draft regulation or document, including indication of the proposed changes to be made to the existing approved plan, where applicable; and

(iv) The requirements of paragraphs (g)(2)(v) through (ix) of this section do not apply to plans submitted for parallel processing. The exceptions granted in the preceding sentence apply only to EPA's determination of proposed action and all requirements of paragraph (g)(2) of this section must be met prior to publication of EPA's final determination of plan approvability.

(h) *Full and partial approval and disapproval.* If a portion of the plan revision meets all the applicable requirements of this chapter, the Administrator may approve the plan revision in part and disapprove the plan revision in part. The Administrator may authorize partial plan submissions in conjunction with a federal plan, where in combination, the federal and State plans constitute a complete and approvable plan meeting all of the requirements of this subpart and the applicable emissions guidelines.

(i) *Conditional approval.* The Administrator may approve a plan or a plan revision based on a commitment of the State, by a date certain established by the Administrator, to adopt specific enforceable measures, review and revise if appropriate State plans, or otherwise commit to making changes in the State's plan necessary to meet the requirements of the applicable emission guidelines. Any such conditional approval automatically converts to a disapproval if the State fails to comply with such commitment by the date certain established by the Administrator.

(j) *Calls for plan revisions.* Whenever the Administrator finds that the applicable plan is substantially inadequate to meet the requirements of the applicable emission guidelines, to provide for the implementation of such plan, or to otherwise comply with any requirement of the Clean Air Act, the Administrator must require the State to revise the plan as necessary to correct such inadequacies. The Administrator must notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions. Such findings and notice must be public. Any finding under this paragraph shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this part to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate.

(k) *Error corrections.* Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or portion thereof) was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public.

PART 62—APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS

■ 3. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 4. Add subpart MMM to read as follows:

Subpart MMM—Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

Applicability of This Subpart

General Requirements

Emission Goals, Set-Asides, and Allowance Allocations

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

Designated Representatives

Monitoring, Recordkeeping, Reporting

Subpart MMM—Greenhouse Gas Emissions Mass-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

§ 62.16205 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Mass-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' is considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

Applicability of this Subpart

§ 62.16210 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator of an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16215 What requirements apply to affected EGUs that retire?

(a) *Exemption.* (1) Any affected EGU that is permanently retired as defined in § 62.16375 is exempt from §§ 62.16220(c)(1) [CO_2 Emissions Requirements], 62.16340 [Compliance Requirements], 62.16345 [Monitoring], 62.16360 [Reporting], and 62.16365 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the facility that includes the unit, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Mass-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

General Requirements

§ 62.16220 What requirements must I comply with?

(a) *Designated representative requirements.* The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16290 through 62.16300.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each facility and each affected EGU at the facility must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16345, 62.16360, and 62.16365.

(2) The emissions data determined in accordance with §§ 62.16345, 62.16360, and 62.16365 must be used to calculate allocations of CO_2 allowances under § 62.16240(a) and (b) and to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance must be the mass emissions amount for the monitoring location determined in accordance with

§ 62.16345 and rounded to the nearest ton.

(c) *CO_2 emission standard requirements*—(1) CO_2 *emission standard.* (i) As of the allowance transfer deadline for a compliance period in a given year, the owners and operators of each facility and each affected EGU at the facility with affected EGUs must hold, in the facility's compliance account, CO_2 allowances available for deduction for such compliance period under § 62.16340(a) in an amount not less than the tons of total CO_2 emissions for such compliance period from all affected EGUs at the facility.

(ii) If total CO_2 emissions during a compliance period in a given year from the affected EGUs at a facility are in excess of the CO_2 emission standard set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the facility and each affected EGU at the facility must hold the CO_2 allowances required for deduction under § 62.16340(d); and

(B) The owners and operators of the facility and each affected EGU at the facility are subject to federal enforcement pursuant to sections 113(a) through (h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its allowances) and secure appropriate corrective actions, and must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act.

(2) *Compliance periods.* (i) An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022 and for each compliance period thereafter.

(ii) [Reserved]

(3) *Vintage of allowances held for compliance.* (i) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in such compliance period or for a year in a prior compliance period.

(ii) A CO_2 allowance held for compliance with the requirements under paragraph (c)(1)(ii)(A) of this section for a compliance period must be a CO_2 allowance that was allocated for a year in a prior compliance period, or the current compliance period, or in the immediately following compliance period.

(4) *Allowance Tracking and Compliance System (ATCS) requirements.* Each CO_2 allowance must be held in, deducted from, or transferred into, out of, or between ATCS accounts in accordance with this subpart.

(5) *Limited authorization.* A CO_2 allowance is a limited authorization to emit one ton of CO_2 during the compliance period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization must only be used in accordance with the CO_2 Mass-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(6) *Property right.* A CO_2 allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) Unless otherwise specified in this paragraph, all requirements of this subpart are applicable requirements that must be included in an affected EGU's title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any allocation, holding, deduction, or transfer of CO_2 allowances in accordance with this subpart, provided that the requirements applicable to such allocations, holdings, deductions, or transfers of CO_2 allowances are already incorporated in such permit.

(e) *Liability.* (1) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU at a facility or the designated representative of affected EGUs at a facility will also apply to the owners and operators of such facility and of the affected EGUs at the facility.

(2) Any provision of the CO_2 Mass-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU will also apply to the owners and operators of such affected EGU.

(f) *Effect on other authorities.* No provision of the CO_2 Mass-based Trading Program or exemption under § 62.16215 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16225 How should I compute time under the CO_2 Mass-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin on the occurrence of an act or event will begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Mass-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Mass-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16230 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Mass-Based Trading Program are set forth in part 78 of this chapter.

§ 62.16231 How will the Clean Energy Incentive Program be administered under the federal plan?

(a)(1) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for which this subpart is promulgated as a federal plan under section 111(d) of the Clean Air Act. The Administrator will award, on behalf of each such state, early action allowances for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE) and demand-side energy efficiency (EE) projects:

(i) Metered wind power;

(ii) Metered solar power; and

(iii) Demand-side EE implemented in a low-income community.

(2) Eligible RE projects must commence construction, and eligible demand-side EE projects must

commence implementation after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action allowances will be distributed pursuant to a process to be prescribed by the Administrator, from an allowance set-aside equal to 300 million allowances for all states. This set-aside does not increase the total budget of allowances for the affected EGUs in the state subject to this subpart.

(c) The Administrator will match these early action allowances with additional matching allowances pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state's pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: for every two MWh generated, the project will receive a number of early action allowances the Administrator determines to be equivalent to one MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to one MWh from the match under paragraph (c) of this section.

(2) For EE projects implemented in low-income communities as determined by the Administrator solely for purposes of this subpart: for every two MWh in end-use demand savings achieved, the project will receive a number of early action allowances the Administrator determines to be equivalent to two MWh from the set-aside under paragraph (b) of this section and a number of matching allowances the Administrator determines to be equivalent to two MWh from the match under paragraph (c) of this section.

Emission Goals, Set-Asides, and Allowance Allocations

§ 62.16235 What are the statewide mass-based emission goals, renewable energy set-asides, output-based set-asides, and Clean Energy Incentive Program early action set-asides?

(a) The statewide mass-based emission goals with renewable energy set-asides and output-based set-asides for allocations of CO_2 allowances for the interim 3- and 2-year compliance periods in 2022 through 2029, and the final 2-year compliance periods in 2030 and thereafter are specified in Table 1 of this subpart.

TABLE 1 TO SUBPART MMM OF PART 62—STATEWIDE MASS-BASED EMISSION GOALS [1] (SHORT TONS)

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Alabama	66,164,470	60,918,973	58,215,989	56,880,474
Arizona	35,189,232	32,371,942	30,906,226	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	30,322,632
California	53,500,107	50,080,840	48,736,877	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	4,711,825
Florida	119,380,477	110,754,683	106,736,177	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	21,700,587
Lands of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,073,942
Maryland	17,447,354	15,842,485	14,902,826	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	55,462,884
Montana	13,776,601	12,500,563	11,749,574	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	16,599,745
New Mexico	14,789,981	13,514,670	12,805,266	12,412,602
New York	35,493,488	32,932,763	31,741,940	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,539,481

TABLE 1 TO SUBPART MMM OF PART 62—STATEWIDE MASS-BASED EMISSION GOALS [1] (SHORT TONS)—Continued

State	Interim period			Final period
	Step 1 2022–2024	Step 2 2025–2027	Step 3 2028–2029	2030–2031 and thereafter
Tennessee	34,118,301	31,079,178	29,343,221	28,348,396
Texas	221,613,296	203,728,060	194,351,330	189,588,842
Utah	28,479,805	25,981,970	24,572,858	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	27,433,111
Washington	12,395,697	11,441,137	10,963,576	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	31,634,412

[1] The values in this table are annual amounts; the mass goal for each multi-year compliance period is the annual value multiplied by the number of years in the compliance period. Each emission goal includes the renewable energy set-asides and output-based set-asides (the output-based set-asides are zero in the first compliance period). The first compliance period goals also include the early action Clean Energy Incentive Program set-aside.

(b) If implementing interstate trading, then the Administrator will use the sum of a covered group of States' mass-based emission goals as the aggregate mass-based emission goal.

(c) The renewable energy set-aside for each State covered by the federal mass-based emissions trading plan must reserve 5 percent from the State's annual allowances prior to allocation of that year's allowances to facilities. The renewable energy set-asides are specified in Table 2 of this subpart.

TABLE 2 TO SUBPART MMM OF PART 62—STATEWIDE RENEWABLE ENERGY SET-ASIDE (SHORT TONS)

State	Interim period			Final period
	Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	Final compliance periods 2030–2031 and thereafter
Alabama	3,308,224	3,045,949	2,910,799	2,844,024
Arizona	1,759,462	1,618,597	1,545,311	1,508,538
Arkansas	1,801,634	1,647,676	1,562,687	1,516,132
California	2,675,005	2,504,042	2,436,844	2,420,506
Colorado	1,789,266	1,632,724	1,544,591	1,495,020
Connecticut	377,789	355,423	347,754	347,076
Delaware	267,418	248,155	239,214	235,591
Florida	5,969,024	5,537,734	5,336,809	5,254,735
Georgia	2,712,897	2,492,754	2,376,741	2,317,342
Idaho	80,776	76,141	74,653	74,643
Illinois	4,019,805	3,656,247	3,446,097	3,323,858
Indiana	4,600,539	4,185,017	3,945,079	3,805,692
Iowa	1,520,418	1,380,771	1,299,099	1,250,907
Kansas	1,338,186	1,214,789	1,142,405	1,099,541
Kentucky	3,837,868	3,484,943	3,278,345	3,156,306
Lands of the Fort Mojave Tribe	31,844	30,017	29,430	29,426
Lands of the Navajo Nation	1,322,470	1,199,978	1,127,887	1,085,029
Lands of the Uintah and Ouray Reservation	137,937	125,161	117,642	113,172
Louisiana	2,101,760	1,923,058	1,824,835	1,771,351
Maine	112,559	105,993	103,809	103,697
Maryland	872,368	792,124	745,141	717,381
Massachusetts	668,037	625,599	609,081	605,237
Michigan	2,842,713	2,594,678	2,455,344	2,377,203
Minnesota	1,365,158	1,243,429	1,173,839	1,133,918
Mississippi	1,447,034	1,339,534	1,287,811	1,265,217
Missouri	3,365,646	3,057,914	2,878,547	2,773,144
Montana	688,830	625,028	587,479	565,155
Nebraska	1,112,318	1,009,641	949,364	913,637
Nevada	753,827	703,632	682,631	676,179
New Hampshire	223,078	208,149	201,857	199,879
New Jersey	912,075	855,377	834,097	829,987
New Mexico	739,499	675,734	640,263	620,630
New York	1,774,674	1,646,638	1,587,097	1,562,871
North Carolina	3,048,792	2,787,462	2,642,825	2,563,312
North Dakota	1,272,659	1,154,781	1,085,405	1,044,162
Ohio	4,425,616	4,035,247	3,814,008	3,688,490
Oklahoma	2,378,881	2,183,251	2,078,869	2,024,410
Oregon	454,886	423,883	410,479	405,933
Pennsylvania	5,304,138	4,860,236	4,619,604	4,491,115
Rhode Island	190,582	179,647	176,134	176,111

TABLE 2 TO SUBPART MMM OF PART 62—STATEWIDE RENEWABLE ENERGY SET-ASIDE (SHORT TONS)—Continued

State	Interim period			Final period
	Compliance period 1 2022–2024	Compliance period 2 2025–2027	Compliance period 3 2028–2029	Final compliance periods 2030–2031 and thereafter
South Carolina	1,551,276	1,416,842	1,341,748	1,299,948
South Dakota	211,559	193,120	182,771	176,974
Tennessee	1,705,915	1,553,959	1,467,161	1,417,420
Texas	11,080,665	10,186,403	9,717,567	9,479,442
Utah	1,423,990	1,299,099	1,228,643	1,188,910
Virginia	1,564,510	1,449,550	1,394,924	1,371,656
Washington	619,785	572,057	548,179	536,959
West Virginia	3,127,851	2,838,139	2,667,633	2,566,267
Wisconsin	1,675,283	1,528,566	1,445,897	1,399,349
Wyoming	1,926,425	1,748,391	1,643,786	1,581,721

(d) The output-based set-aside for each State under this subpart, beginning in compliance period 2, must reserve a share of the State's annual allowances prior to allocation of that year's allowances to facilities as set forth in this paragraph (d). The output-based set-asides are specified in Table 3 of this subpart.

TABLE 3 TO SUBPART MMM OF PART 62—STATEWIDE OUTPUT-BASED SET-ASIDE (SHORT TONS)

State	Allowances in output-based set-aside (short tons)
Alabama	4,185,496
Arizona	4,197,813
Arkansas	2,102,538
California	8,458,604
Colorado	1,348,187
Connecticut	1,090,811
Delaware	649,190
Florida	12,102,688
Georgia	3,563,104
Idaho	246,638
Illinois	1,598,615
Indiana	1,106,150
Iowa	492,510
Kansas	62,257
Kentucky	288,730
Lands of the Fort Mojave Tribe	248,127
Lands of the Navajo Nation	0
Lands of the Uintah and Ouray Reservation	0
Louisiana	2,207,879
Maine	563,925
Maryland	103,762
Massachusetts	2,439,991
Michigan	2,105,786
Minnesota	909,724
Mississippi	3,132,671
Missouri	815,210
Montana	0
Nebraska	144,635
Nevada	2,326,529
New Hampshire	542,721
New Jersey	3,413,100
New Mexico	627,085
New York	3,815,381
North Carolina	2,120,178
North Dakota	0
Ohio	1,757,326
Oklahoma	3,121,167
Oregon	1,291,027
Pennsylvania	4,392,931
Rhode Island	778,307
South Carolina	1,029,366
South Dakota	130,831
Tennessee	632,949
Texas	15,990,657
Utah	825,586
Virginia	3,011,811

TABLE 3 TO SUBPART MMM OF PART 62—STATEWIDE OUTPUT-BASED SET-ASIDE (SHORT TONS)—Continued

State	Allowances in output-based set-aside (short tons)
Washington	1,383,060
West Virginia	0
Wisconsin	1,181,175
Wyoming	45,114

(e)(1) The Clean Energy Investment Program Set-Aside for each State covered under this subpart must contain an amount of allowances shown in Table 4 of this subpart, which must reserve a share of the State's annual allowances prior to allocation of that year's allowances to facilities as set forth in this paragraph.

TABLE 4 TO SUBPART MMM OF PART 62—CLEAN ENERGY INVESTMENT PROGRAM EARLY ACTION SET-ASIDE (SHORT TONS)

State	Allowances in early action set-aside (short tons)
Alabama	3,122,306
Arizona	1,719,618
Arkansas	2,187,230
California	218,846
Colorado	2,223,192
Connecticut	69,415
Delaware	138,392
Florida	3,230,248
Georgia	2,755,623
Idaho	14,929
Illinois	5,968,721
Indiana	5,754,076
Iowa	2,191,183
Kansas	2,115,630
Kentucky	4,952,862
Lands of the Fort Mojave Tribe	5,885
Lands of the Navajo Nation	1,623,066
Lands of the Uintah and Ouray Reservation	175,509
Louisiana	1,497,428
Maine	20,739
Maryland	972,775
Massachusetts	170,471
Michigan	3,727,861
Minnesota	2,002,903
Mississippi	357,307
Missouri	3,771,322
Montana	1,310,344
Nebraska	1,481,695
Nevada	336,288
New Hampshire	107,798
New Jersey	446,005
New Mexico	823,049
New York	557,771
North Carolina	2,674,590
North Dakota	2,150,635
Ohio	4,788,372
Oklahoma	2,067,006
Oregon	154,353
Pennsylvania	5,039,346
Rhode Island	35,674
South Carolina	1,652,802
South Dakota	264,207
Tennessee	2,178,084
Texas	10,400,192
Utah	1,401,189
Virginia	1,386,546
Washington	751,434
West Virginia	3,506,890
Wisconsin	2,393,870
Wyoming	3,104,324

(2) Allowances may be distributed from the set-aside for projects meeting the criteria of paragraph (e)(3) of this section, upon application of a project proponent that meets the requirements of § 62.16245(a), except as may be prescribed by the Administrator in a future action. In order to receive a distribution, the project proponent must establish a general account in the tracking system as provided in § 62.16320(c).

(3) Projects eligible for distribution of allowances from this set-aside must meet each of the criteria in paragraphs (e)(3)(i) through (iii) of this section. All categories of resources other than those listed in paragraphs (e)(3)(iii)(A) and (B) of this section, and all provisions of this subpart relating to such resources, are not available or applicable in States where this subpart has been promulgated as a federal plan pursuant to section 111(d)(2) of the Clean Air Act.

(i) The project was constructed or implemented on or after the signature date of the final rule promulgating subpart UUUU of part 60 of this chapter;

(ii) The creditable generation or energy savings from the project must occur in calendar years 2020 or 2021; and

(iii) Generation or energy savings must be from one of the following types of sources capable of revenue-quality metering:

(A) Onshore wind;

(B) Solar; or

(C) Demand-side EE.

§ 62.16240 When are allowances allocated?

(a) *Allowance allocations.* (1) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, CO_2 allowances will be allocated, for the multi-year compliance periods in the Interim Period beginning in 2022 and the Final Period beginning in 2030, as provided by the Administrator in a notice of data availability or through this subpart (if applicable). Providing an allocation to an entity does not constitute as an applicability determination of an affected EGU.

(2) Notwithstanding paragraph (a)(1) of this section, if an affected EGU which is provided an allocation does not operate for 2 consecutive calendar years, then such affected EGU will not be allocated the CO_2 allowances provided by the Administrator in a notice of data availability or through this subpart (if applicable) for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(3) Notwithstanding paragraph (a)(1) of this section, if an affected EGU provided an allocation issued by the Administrator in notice of data availability or through this subpart (if applicable) is modified or reconstructed such that it is no longer subject to this subpart, then such affected EGU will not be allocated the CO_2 allowances provided for the affected EGU for the next compliance period for which allowances have not yet been recorded and for each compliance period after that compliance period. All CO_2 allowances that would otherwise have been allocated to such affected EGU will be allocated to the renewable energy set-aside for the State where such affected EGU is located and for the respective compliance periods involved.

(b) *Set-asides*—(1) *Renewable energy set-asides.* (i) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each approved renewal energy project in a State, in accordance with § 62.16245(a)(2) through (5), for the generation year of the applicable calculation deadline under this paragraph.

(ii) By December 1, 2021 and December 1 of each year thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(a)(6) and (7) for the generation year of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(2) *Output-based set-asides.* (i) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(3), for the generation period of the applicable calculation deadline under this paragraph.

(ii) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will calculate and allocate the CO_2 allowance allocation to each affected EGU in a State, in accordance with § 62.16245(b)(4) and (5) for the generation period of the applicable calculation, and will promulgate a notice of data availability of the results of the calculations.

(c) *Affected EGUs incorrectly allocated CO_2 allowances.* (1) For each compliance period in 2022 and thereafter, if the Administrator determines that CO_2 allowances were allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under § 62.16245(a) and (b), where such compliance period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section. The situations for the Administrator to act according to the procedures in paragraphs (c)(2) through (5) are if:

(i)(A) The recipient is not actually an affected EGU under § 62.16210 as of January 1, 2022 and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1, 2022 and is allocated CO_2 allowances for such compliance period that the state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1, 2022; or

(B) The recipient is not located as of January 1 of the compliance period in the State from whose CO_2 allowances the CO_2 allowances allocated under paragraph (a) of this section, or under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, were allocated for such compliance period.

(ii) The recipient is not actually an affected EGU under § 62.16210 as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period or, in the case of an allocation under a provision of a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter, the recipient is not actually an affected EGU as of January 1 of such compliance period and is allocated CO_2 allowances for such compliance period that the state allowance distribution methodology provides should be allocated only to recipients that are affected EGUs as of January 1 of such compliance period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CO_2 allowances under § 62.16325.

(3) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the facility that includes such recipient under § 62.16340(b) for such compliance period, then the Administrator will deduct from the account in which such CO_2 allowances were recorded an amount of CO_2 allowances allocated for the same or a prior compliance period equal to the amount of such already-recorded CO_2 allowances. The authorized account representative must ensure that there are sufficient CO_2 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CO_2 allowances under § 62.16325 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the facility that includes such recipient under § 62.16340(b) for such compliance period, then the Administrator will not make any deduction to take account of such already-recorded CO_2 allowances.

(5)(i) With regard to the CO_2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period for the State from whose CO_2 allowances the CO_2 allowances were allocated; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(ii) With regard to the CO_2 allowances that were not allocated from a renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will:

(A) Transfer such CO_2 allowances to the renewable energy set-aside for such compliance period; or

(B) If the State has a state allowance distribution methodology approved under subpart UUUU of part 60 of this chapter covering such compliance period, then include such CO_2 allowances in the portion of the CO_2 allowances that may be allocated for such compliance period in accordance with such state allowance distribution methodology.

(iii) With regard to the CO_2 allowances that were allocated from the renewable energy or output-based set-aside for such compliance period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this section, the Administrator will transfer such CO_2 allowances back to the renewable energy set-aside, or to the output-based set-aside, respectively, for such compliance period.

§ 62.16245 How are set-aside allowances allocated?

(a)(1) *Renewable energy set-aside.* The Administrator will establish a renewable energy set-aside as set forth in § 62.16235(c), and allocate CO_2 allowances from the set-aside for each year of a compliance period as outlined in this section.

(2) *Eligible renewable energy capacity.* To be eligible to receive renewable energy set-aside allowances, an eligible resource must meet each of the requirements in paragraphs (a)(2)(i) through (v) of this section. Any resource that does not meet the requirements of paragraphs (a)(2)(i) through (v) of this section cannot receive set-aside allowances.

(i) The resource must be a renewable energy resource that falls into one of the following categories of resources: on-shore utility scale wind, solar, geothermal power, or utility scale hydropower.

(ii) The resources must only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then set-aside allowances may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. Set-aside allowances must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued set-aside allowances.

(iii) The resource must be located in the mass-based State for which the set-aside has been designated.

(iv) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(v) The resource must not have received emission rate credits (ERCs) for any period of time for which it receives set-aside allowances.

(3) *Process for issuance of set-aside allowances.* The process and requirements for issuance of set-aside allowances are set forth in paragraphs (a)(3)(i) through (x) of this section.

(i) Eligibility application. To receive set-aside allowances, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of paragraph (a)(2) of this section are met and demonstrates that the following requirements are met:

(A) Identification of the authorized account representative of the eligible resource, including the authorized account representative's name, address, email address, telephone number, and allowance tracking system account number; and

(B) Identification of the eligible resource(s), including the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the authorized account representative and designated representative; generator prime mover and technology type; generator nameplate capacity (if applicable); generator category (*e.g.,* wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable) (if applicable); the control area, balancing authority, ISO conditions as defined in § 62.16375 (if applicable), or regional transmission organization in which the generator is located (if applicable); and a copy of the most recent filing of a copy of the generating facility's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860 (if applicable).

(ii) Renewable energy providers must open a general account per the requirements in § 62.16320(c), and submit a project application for renewable energy set-aside allowances to the Administrator by June 1 of the year prior to the generation year for which set-aside allowances are requested. Providers may update submitted projections for future generation years, these projections must be received by June 1 of the year prior to the generation year in question. The project application must contain the following information:

(A) Projection of the project's annual renewable energy generation in MWh.

(B) Documentation of the methodology, data facilities, and assumptions used to project the project's annual renewable energy generation.

(C) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-State approach where States are providing for joint issuance of allowances pursuant to the authority in their individual State plans.

(D) A evaluation, measurement, and verification (EM&V) plan.

(E) A verification report from an accredited independent verifier who meets the requirements of § 62.16275 and § 62.16280. While considered a part of the eligibility application, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(F) An authorization that provides for the following: the Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(G) The following statement, signed by the authorized account representative of the eligible resource:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

(H) Any other information required by the Administrator.

(4) *Monitoring and verification.* After the generation year for which a provider received set-aside allowances for an eligible resource, the authorized account representative must submit to the Administrator:

(i) A measurement and verification (M&V) report.

(ii) A verification report from an accredited independent verifier that meets the requirements of § 62.16275 and § 62.16280. While considered a part of the M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(5) *Allocation of renewable energy set-aside allowances.* The Administrator will enter the projected generation from each approved project into a pool of projects for that State that will receive set-asides for a generation year.

(i) The Administrator will distribute renewable energy set-aside allowances for a generation year with the number of allowances distributed to each project prorated according to its percentage of the total approved projected MWhs for that State that the project represents.

(ii) If in the previous generation year, the project did not reach the MWhs projected, then the unfulfilled MWhs will be subtracted from that provider's projected generation eligible for the set-aside pool.

(iii) If the unfulfilled MWhs from a previous year exceed the projected hours for the generation year, then the Administrator will carry over the deficit and subtract from the projected generation in subsequent years until there is no deficit. If this deficit is greater than 10 percent in a particular year, then the provider will need to provide an explanation to the Administrator of the deficit, and will be required to reevaluate their projections for future years. If such deficits continue through all 3 years of the first or second compliance period, then the Administrator will disqualify the provider from receiving future set-asides for the following compliance period.

(6) *Surplus renewable set-aside allowances.* If, after completion of the procedures under paragraph (a)(5) of this section for each compliance period, any unallocated CO_2 allowances remain in the renewable energy set-aside for the State for such generation year, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(7) *Notice of surplus renewable energy set-aside allowance distribution.* The Administrator will make public the amount of CO_2 allowances allocated under paragraph (a)(6) of this section for such generation year period to each affected EGU eligible for such allocation.

(b)(1) *Output-based set-aside.* The Administrator will establish an output-based set-aside beginning in compliance period 2, and allocate CO_2 allowances from the set-aside for each year of a compliance period as set forth in § 62.16235(c).

(2) *Unit eligibility.* To be eligible to receive output-based set-aside allowances, affected EGUs must meet the following eligibility requirements:

(i) The affected EGU must be a natural gas combined cycle unit;

(ii) The affected EGU must be located in the mass-based State for which the set-aside has been designated; and

(iii) The affected EGU's average capacity factor in the preceding compliance period was above 50 percent based on net summer capacity and net generation.

(3) *Allocation of output-based set-aside allowances.* The Administrator will allocate output based set-aside allowances for each eligible EGU based on its average net generation and net summer capacity in the preceding compliance period.

(i) The Administrator will calculate the amount of allowances an eligible EGU receives from the output-based set-aside as the unit's average net generation in the preceding compliance period over 50 percent multiplied by the allocation rate of 1,030 lb/MWh-net.

(ii) If the amount of total allowances exceeds the size of the State's set-aside, then the allowances will be allocated to the State's eligible generation on a pro-rata basis.

(iii) The Administrator will provide notice of the net summer capacity and net generation data used, and the resulting allocations by August 1 of the first year of each compliance period beginning in 2025. The notice of the net summer capacity and net generation data used, and the resulting allocations, must allow 30 days for public comment on the data and allocations, until August 31 of the same year.

(iv) The Administrator will provide notice of the final set-aside allocations by November 1 of the same year.

(4) *Surplus output-based set-aside allowances.* If, after completion of the

procedures under paragraph (b)(3) of this section for each compliance period, any unallocated CO_2 allowances remain in the out-put based set-aside for the State for such generation period, the Administrator will allocate the amount of CO_2 allowances in a pro rata fashion on the same distribution basis as their initial allocations were made to each affected EGU that: is in the State; is allocated an amount of CO_2 allowances in the notice of data availability issued under § 62.16240(a)(1); and continues to be allocated CO_2 allowances for such compliance period in accordance with § 62.16240(a)(2).

(5) *Notice of surplus output-based set-aside.* The Administrator will notify the public, through the promulgation of the notices of data availability described in § 62.16240(b)(1) and (2), of the amount of CO_2 allowances allocated under paragraphs (b)(3) and (4) of this section for such compliance period to each affected EGU eligible for such allocation.

§ 62.16250 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16260 in the CO_2 Mass-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued set-aside allowances. In addition, the provisions of § 62.16255(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or M&V report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, or in any other submissions may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued set-aside allowances.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued allowances. In addition, the provisions of § 62.16255(a) through (d) may apply.

§ 62.16255 What is the process for error adjustments or misstatement, and suspension of allowance issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which set-aside allowances have been issued, the Administrator may adjust the number of set-aside allowances issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which set-aside allowances have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which set-aside allowances have been issued, the Administrator will revoke set-aside allowances from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of set-aside allowances to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of set-aside allowances necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines set-aside allowances have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which set-aside allowances have been issued. Freezing a general account will prevent transfer of allowances out of the account.

(d) If set-aside allowances are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(1) through (3) of this section.

(1) Freeze the general account of the authorized account representative for an eligible resource, preventing any transfers of allowances out of the account.

(2) Revoke or deduct allowances held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of allowances issued for the ineligible eligible resource.

(3) In the event that the general account of the eligible resource holds a number of allowances less than the number of set-aside allowances issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of allowances necessary to fully account for all allowances issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of set-aside allowances for an eligible resource, for the following reasons in paragraphs (e)(1) through (3) of this section.

(1) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which set-aside allowances have been issued, or the eligibility status of an eligible resource.

(2) In the case of repeated error or misstatements in submitted M&V reports.

(3) In the case of an intentional misrepresentation in a submitted M&V report.

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

§ 62.16260 What are the requirements for evaluation, measurement and verification plans for eligible resources?

(a) *EM&V plan requirements.* Any EM&V plan submitted in support of the issuance of a set-aside allowance pursuant to this rule must meet the requirements of this section.

(b) *General EM&V plan criteria.* Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) *Specific EM&V plan criteria.* Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section must be met.

(i) The generation data are physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data are measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data were measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data are collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire set-aside allowances issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, then the data may be self-reported and reported no less than annually.

(v) The generation data serve a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) Set-aside allowances shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation (''station service'') or parasitic load on the generator's side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, set-aside allowances may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) through (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, then the data may be reported no less than annually.

(v) The generation data are self-reported to the distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(vi) The generation data serves a load that otherwise would have been served by the grid if not for the generator. The set-aside allowance is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vii) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraph (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock, and its associated biogenic CO_2, have been met.

(4) For a waste-to-energy resource, in addition to the requirements of paragraph (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste; and

(iii) The net energy output is measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrates that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section,

as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540 of this subpart.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided transmission and distribution (T&D) system losses can be assessed as is commonly practiced with demand-side EE.

(6) For electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the site-level electricity savings measured at the end use meter or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile expressed as a percentage. No other transmission and distribution loss factors may be used in calculating the electricity savings, including measures such as conservation voltage reduction and volt/VAR optimization.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE measure covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (*e.g.,* installed as part of a utility EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: PB–MV, comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited—with adequate advance notification (via the internet and other social media)—to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience—for example, with new and innovative EE program types—necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2 or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (*i.e.,* factors that are not directly related to the EE measure, such as weather, occupancy, and production levels).

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, are operating as intended, and therefore have the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer's premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (*e.g.,* lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than +/−10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16265 What are the requirements for monitoring and verification reports for eligible resources?

(a) *M&V report requirements.* Any M&V report that is submitted, in support of the issuance of a set-aside allowance that can be used in accordance with § 62.16240, must meet the requirements of this section.

(b) *General M&V report criteria.* Each M&V report must include the information in paragraphs (b)(1) and (2) of this section.

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16245(a)(3).

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (*e.g.,* nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16270 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued set-aside allowances pursuant to this regulation, in accordance with § 62.16245(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16245;

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan;

(3) The eligible resource exists or the operation or activity will be implemented in the manner specified in the eligibility application;

(4) That the EM&V plan meets the requirements of § 62.16260;

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (*e.g.,* reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system); and

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of an M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the information specified in paragraphs (c)(1) through (3) of this section.

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the authorized account representative seeks issuance of set-aside allowances, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data is within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the allowance tracking system. If the data entered exceeds the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16265.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

§ 62.16275 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the Administrator's CO_2 Mass-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification opinion, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of paragraph (c)(1) of this section. Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of § 62.16280(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either Standard & Poor's or Moody's, specifically, AAA, AA, A or BBB for Standard & Poor's, and Aaa, Aa, A, or Baa for Moody's. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) *Requirements for maintenance of accreditation status.*

(1) Accredited independent verifiers must meet the requirements of § 62.16280 when providing verification services for an authorized account representative.

(2) The instances specified in § 62.16280(d) are cause for revocation of a verifier's accreditation.

§ 62.16280 What are the procedures accredited independent verifiers must follow to avoid conflict of interest?

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of set-aside allowances, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, set-aside allowance issuance, or the number of set-aside allowances issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold set-aside allowances, or other financial derivatives related to set-aside allowances, or have a financial relationship with other parties that own, buy, sell, or hold set-aside allowances or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI, which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and set-aside allowances must not be issued pursuant to it.

§ 62.16285 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16280(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16270, 62.16275, and 62.16280.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

Designated Representatives

§ 62.16290 How are designated representatives and alternate designated representatives authorized, and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16300, each facility, including all affected EGUs at the facility, shall have one and only one designated representative, with regard to all matters under the CO_2 Mass-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the facility and each affected EGU at the facility in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the designated representative by the Administrator regarding the facility or any such affected EGU.

(b) Except as provided under § 62.16300, each facility may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the facility and all affected EGUs at the facility and must act in accordance with the certification statement in § 62.16305(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16305:

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the facility and each affected EGU at the facility shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the facility or any such affected EGU.

(c) Except in this section, § 62.16375, and §§ 62.16295 through 62.16315, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 62.16295 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16315 concerning delegation of authority to make submissions, each submission under the CO_2 Mass-based Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each facility and affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility or affected EGUs for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for a facility or an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16315.

§ 62.16300 What are the processes for changing designated representative, alternate designated representative, owners and operators, and affected EGUs at the facility?

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the facility and the affected EGUs at the facility.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16305. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the facility and the affected EGUs at the facility.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a facility or an affected EGU at the facility is not included in the list of owners and operators in the certificate of representation under § 62.16305, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a facility or an affected EGU at the facility, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16305 amending the list of owners and operators to reflect the change.

(d) *Changes in affected EGUs at the facility.* Within 30 days of any change in which affected EGUs are located at a facility (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16305 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the facility, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the facility.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, email address and facsimile transmission number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the facility.

§ 62.16305 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the following elements in a format prescribed by the Administrator:

(1) Identification of the facility, and each affected EGU at the facility, for which the certificate of representation is submitted, including facility and affected EGU names, facility category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU, actual or projected date of commencement of commercial operation, net summer capacity at the affect EGU, and a statement of whether such facility is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility and of each affected EGU at the facility.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility and each affected EGU at the facility''; and

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of the owners and operators of the facility and of each affected EGU at the facility and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the facility or unit.''

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility and of each affected EGU at the facility; and CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CO_2 allowances by contract, then CO_2 allowances and proceeds of transactions involving CO_2 Mass-based Trading allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16310 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16305 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16305 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

§ 62.16315 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the elements in paragraphs (c)(1) through (4) of this section.

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'').

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her.

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16315(d) shall be deemed to be an electronic submission by me''; and

(ii) ''Until this notice of delegation is superseded by another notice of delegation under § 62.16315(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16315 is terminated.''

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping, Reporting

§ 62.16320 How are compliance accounts and general accounts established?

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under § 62.16305, the Administrator will establish a compliance account for the facility for which the certificate of representation was submitted, unless the facility already has a compliance account. The designated representative and any alternate designated representative of the facility shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *Retirement accounts.* (1) A retirement account, into which allowances held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and allowances deposited into it are permanently retired. Once an allowance is retired, the allowance shall no longer be transferable to another account in that allowance tracking system or any other allowance tracking system.

(2) [Reserved]

(c) *General accounts*—(1) *Application for a general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring CO_2 allowances, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to CO_2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the CO_2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Mass-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account''; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CO_2 allowances held in the general account in all matters pertaining to the CO_2 Mass-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to CO_2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to CO_2 allowances held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the CO_2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to CO_2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the

CO_2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Mass-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of CO_2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv) shall be deemed to be an electronic submission by me''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under § 62.16320(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16320(c)(5) is terminated.''

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted CO_2 allowance transfer under § 62.16330 for any CO_2 allowances in the account to one or more other ATCS accounts.

(ii) If a general account has no CO_2 allowance transfers to or from the account for a 12-month period or longer and does not contain any CO_2 allowances, then the Administrator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted CO_2 allowance transfer under § 62.16330 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CO_2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§ 62.16295(a) and 62.16315 or paragraphs (c)(2)(ii) and (c)(5) of this section.

§ 62.16325 When will CO_2 allowances be recorded in compliance accounts?

(a) By June 1, 2021, and by June 1 of each year prior to the beginning of each compliance period thereafter, the Administrator will record in each facility's compliance account the CO_2 allowances allocated to the affected EGUs at the facility in accordance with § 62.16240(a), or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the upcoming compliance period.

(b) Except as specified in paragraph (a) of this section, the Administrator will record an allocation in the appropriate ATCS account by the date on which any allocation of CO_2 allowances to a recipient must be made by or submitted to the Administrator in accordance with either § 62.16240 or with state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter.

(c) When recording the allocation of CO_2 allowances to an affected EGU or other entity in an ATCS account, the Administrator will assign each CO_2 allowance a unique serial number that will include digits identifying the year of the compliance period for which the CO_2 allowance is allocated.

(d) By December 1, 2021 and December 1 of each year thereafter, the Administrator will record in each renewable energy project's general account, the CO_2 allowances allocated from the renewable energy set-aside to the project in accordance with § 62.16245(a), for the following year.

(e) By November 1 of the first year of each compliance period beginning in 2025, and each compliance period thereafter, the Administrator will record in each facility's compliance account the CO_2 allowances allocated from the output-based set-aside to the eligible EGUs at the facility in accordance with § 62.16245(b) or with a state allowance-distribution methodology approved under subpart UUUU of part 60 of this chapter, for the following year.

§ 62.16330 How must transfers of CO_2 allowances be submitted?

(a) An authorized account representative seeking recordation of a CO_2 allowance transfer must submit the transfer to the Administrator.

(b) A CO_2 allowance transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each CO_2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each CO_2 allowance identified by serial number in the transfer.

§ 62.16335 When will CO_2 allowance transfers be recorded?

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CO_2 allowance transfer that is correctly submitted under § 62.16330, the Administrator will record a CO_2 allowance transfer by moving each CO_2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A CO_2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any CO_2 allowances allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16340 for the compliance period immediately before such allowance transfer deadline.

(c) Where a CO_2 allowance transfer is not correctly submitted under § 62.16330, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a CO_2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a CO_2 allowance transfer that is not correctly submitted under § 62.16330, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16340 How will deductions for compliance with a CO_2 emission standard occur?

(a) *Availability for deduction for compliance.* CO_2 allowances are available to be deducted for compliance with a facility's CO_2 emission standard for a compliance period only if the CO_2 allowances:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the facility's compliance account as of the allowance transfer deadline for such compliance period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 62.16335, of CO_2 allowance transfers submitted by the allowance transfer deadline for a compliance period, the Administrator will deduct from each facility's compliance account CO_2 allowances available under paragraph (a) of this section in order to determine whether the facility meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of CO_2 allowances deducted equals the number of tons of total CO_2 emissions from all affected EGUs at the facility for such compliance period; or

(2) If there are insufficient CO_2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more CO_2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CO_2 allowances by serial number.* The authorized account representative for a facility's compliance account may request that specific CO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (d) of this section. In order to be complete, such request must be submitted to the Administrator by the allowance transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the facility and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CO_2 allowances under paragraph (b) or (d) of this section from the facility's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of CO_2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any CO_2 allowances that were allocated to the affected EGUs at the facility and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any CO_2 allowances that were allocated to any affected EGU or other entity and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the facility has excess emissions, the Administrator will deduct from the facility's compliance account an amount of CO_2 allowances, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the facility's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 62.16345 What monitoring requirements must I comply with?

(a) The owner or operator of an affected EGU must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter. You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) For each operating hour, calculate the hourly CO_2 mass (tons) according to paragraph (a)(4) or (5) of this section, except that a complete data record is required, *i.e.,* CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or gross calorific value (GCV) must be used in the calculations; and

(2) Sum all of the hourly CO_2 mass emissions values over the entire compliance period.

(3) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output (P_{net}). The owner or operator must calculate net energy output according to paragraphs (a)(6)(i)(A) and (B) of this section.

(4) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(4)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(5) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), then this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) Calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis). CO_2 mass emissions must be reported for each operating hour. Therefore, substitute data values recorded under part 75 of this chapter for CO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate and/or GCV must be used in the calculations.

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter, if required by a plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(5) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(4) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(5)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) Determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6), if required by a plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) that were calculated according to procedures specified in paragraph (a)(5)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(6) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(6)(i) of this section.

(i) For each operating hour of a compliance period that was used in paragraph (a)(4) or (5) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(6)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(4) or (5) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output must be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(6)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in § 62.16375, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions as defined in § 62.16375, as applicable) from any integrated equipment that is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16375, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in § 62.16375 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(ii) [Reserved]

(7) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(1) of this section share a common exhaust gas stack and are subject to the same emissions standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and the operating time must be expressed as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(8) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(b) [Reserved]

§ 62.16350 May I bank CO_2 annual allowances for future use or transfer?

(a) A CO_2 allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CO_2 allowance is deducted or transferred under §§ 62.16240(b), 62.16335, 62.16340, 62.16355, or 62.16370.

§ 62.16355 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any ATCS account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16360 What are my reporting, notification and submission requirements?

(a) You must prepare and submit reports according to paragraphs (a) through (e) of this section, as applicable.

(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The hourly CO_2 mass emission rate value (tons/hr) and unit (or stack) operating time, as monitored and reported according to part 75 of this chapter, for each unit or stack operating hour in the compliance period;

(ii) The calculated CO_2 mass emissions (tons) for each unit or stack operating hour in the compliance period;

(iii) The sum of the CO_2 mass emissions (tons) for all of the unit or stack operating hours in the compliance period;

(iv) The net electric output and the net energy output (P_{net}) values for each unit or stack operating hour in the compliance period;

(v) The sum of the hourly net energy output values for all of the unit or stack operating hours in the compliance period; and

(vi) If the report covers the final quarter of a compliance period, then you must include the CO_2 emission standard with which your affected EGU must comply, the affected EGU's calculated emission performance as a cumulative mass in units of the emission standard required, and if an affected EGU is complying with an emission standard by using allowances, then the designated representative must include in their report a list of all unique allowance serial numbers retired in the compliance period, and, for each allowance, the date an allowance was surrendered and retired. If set-aside allowances were used from an eligible resource by an affected EGU to comply with its emission standard, then the designated representative must include in their report the eligible resource identification information sufficient to demonstrate that it meets the requirements of § 62.16245 and qualifies to be issued allowance set-asides (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the allowance was issued).

(2) [Reserved]

(b) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Mass-based Trading Program, except as provided in § 62.16315. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(c) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(d) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(e) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of 40 CFR part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, of this chapter, if injection occurs off site.

(f) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16365 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraphs (a)(1) and (2) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records:

(i) All emissions monitoring information, in accordance with this subpart;

(ii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU's emission standard under § 62.16220 and any other requirements of, the CO_2 Mass-based Trading Program;

(iii) Data that is required to be recorded by 40 CFR part 75, subpart F, of this chapter; and

(iv) Data with respect to any allowances used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(2)(iv)(A) and (B) of this section.

(A) All documents related to any set-aside allowances used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific set-aside allowance, and each regulatory approval and any documentation that supports the issuance of each set-aside allowance by the Administrator.

(B) All records and reports relating to the surrender and retirement of allowances for compliance with this regulation, including the date each individual allowance with a unique serial identification number was surrendered and/or retired.

(b) [Reserved]

§ 62.16370 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Mass-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct CO_2 allowances from or transfer CO_2 allowances to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16375 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or *Affected EGU* means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allocate or allocation means, with regard to CO_2 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart or any state allowance-distribution methodology submitted by the State and approved by the Administrator under § 62.16245, to:

(1) An affected EGU;

(2) A renewable energy set-aside;

(3) An output-based set-aside; or

(4) Any other entity specified by the Administrator.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent state or federal CO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the affected EGU's heat rate in mmBtu/MWh) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrator records allocations, deductions, and transfers of CO_2 allowances under the CO_2 Mass-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance transfer deadline means, for a compliance period in a given year, midnight of May 1 (if it is a business day), or midnight of the first business day thereafter (if May 1 is not a business day), immediately after such compliance period and is the deadline by which a CO_2 allowance transfer must be submitted for recordation in a facility's compliance account in order to be available for use in complying with the facility's CO_2 emission standard for such compliance period in accordance with §§ 62.16220 and 62.16340.

Alternate designated representative means, for a CO_2 Mass-based Trading Program facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Mass-based Trading Program. If the facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an affected EGU during a calendar year and the potential heat input to the affected EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of CO_2 allowances held in the general account and, for a CO_2 Mass-based Trading facility's compliance account, the designated representative of the facility is the authorized account representative.

Automated data acquisition and handling system (DAHS) means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (*e.g.,* trees, crops, grasses, tree litter, roots) above and below ground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or state, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

CO_2 allowance means a limited authorization issued and allocated by the Administrator under this subpart, or by a State or permitting authority under a state allowance-distribution methodology approved by the Administrator under § 60.24(x) of this chapter, to emit one ton of CO_2 during a compliance period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CO_2 Mass-Based Trading Program.

CO_2 allowance deduction or deduct CO_2 allowances means the permanent withdrawal of CO_2 allowances by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the CO_2 emission standard).

CO_2 allowances held or hold CO_2 allowances means the CO_2 allowances treated as included in an Allowance Tracking and Compliance System (ATCS) account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, CO_2 allowance transfer in accordance with this subpart.

CO_2 emission goal means a statewide rate-based CO_2 emission goal or mass-based CO_2 emission goal specified in § 62.16235.

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the facility under § 62.16340(a) for such compliance period.

CO_2 Mass-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the Administrator under subpart UUUU of part 60 of this chapter), as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or CHP unit, (also known as *''cogeneration''*) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy facility.

Common practice baseline (CPB) means a baseline derived based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means an ATCS account, established by the Administrator for a CO_2 annual facility under this subpart, in which any CO_2 allowance allocations to the affected EGUs at the facility are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the facility's CO_2 emission standard in accordance with §§ 62.16220 and 62.16340.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16220(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024.

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027.

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) (CVR) means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system (*CEMS)* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16345. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: Has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand-side EE means energy efficiency activities, projects, programs or measures resulting in electricity savings.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Designated representative means, for a CO_2 Mass-based Trading facility and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the facility and all such affected EGUs at the facility, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Mass-based Trading Program. If the CO_2 Mass-based Trading facility is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by EE program.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency program or *EE program* means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of an EE measure.

Eligible resource means a resource that meets the requirements of § 62.16245 and has been registered with the EPA-administered ATCS or an allowance tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16260.

Emissions means air pollutants exhausted from an affected EGU or facility into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, and in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

Energy service company means a private enterprise engaged in delivering electricity savings directly for an end-use customer or as an agent of a sponsoring entity such as a utility.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating facility for generating allowances pursuant to this regulation, including the type of facility.

Excess emissions means any ton of emissions from the affected EGUs at a facility during a compliance period that exceeds the CO_2 emissions limitation for the facility for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an ATCS account established under this subpart that is not a compliance account.

Generation period means the compliance period from which the Administrator uses operations data of affected EGUs to calculate allowances from the output-based allocation set-aside for the following compliance period.

Generation year means a calendar year for which a renewable energy project submits its projected generation to the Administrator by June 1 of the preceding year for allowances from the renewable energy set-aside.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16265.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) of such completion as specified by the person conducting the physical change.

Natural gas means the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (*e.g.,* steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (*e.g.,* steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or *operation* means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any person who operates, controls, or supervises an affected EGU at the facility or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such facility or affected EGU.

Owner means, for a CO_2 Mass-based Trading facility or an affected EGU at a facility respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the facility or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the facility or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, ''owner'' does not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from an affected EGU at the facility or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners and operators: have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16215; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Qualified biomass means a biomass feedstock that is demonstrated as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CO_2 allowances, the moving of CO_2 allowances by the Administrator into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25° C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16270.

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

§ 62.16380 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR—alternated designated representative
Btu—British thermal unit
CO_2—carbon dioxide
COI—conflict of interest
CPP—clean power plan
CVR—conservation voltage regulation
DR—designated representative
EE—energy efficiency
EGU—electric generating unit
EM&V—evaluation, measurement, and verification
GCV—gross calorific value
GJ—giga joule
H_2O—water
hr—hour
IGCC—integrated gasification combined cycle
kg—kilogram
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
M&V—measurement and verification
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
O_2—oxygen
PB–MV—project-based measurement and verification
PSD—prevention of significant deterioration
T&D—transmission and distribution
TRM—technical reference manual
yr—year

■ 5. Add subpart NNN to read as follows:

Subpart NNN—Greenhouse Gas Emissions Rate-based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Sec.

Subpart NNN—Greenhouse Gas Emissions Rate-Based Model Trading Rule for Electric Utility Generating Units That Commenced Construction on or Before January 8, 2014

Introduction

§ 62.16405 What is the purpose of this subpart?

(a) This subpart sets forth the requirements for the Clean Power Plan (CPP) CO_2 Rate-based Trading Program, under section 111 of the Clean Air Act and subpart UUUU of part 60 of this chapter, as a means of meeting emission guidelines limiting greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine.

(b) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas limitations in this subpart are in the form of an emission standard for carbon dioxide (CO_2).

(c) *PSD and Title V thresholds for greenhouse gases.* (1) For the purposes of § 51.166(b)(49)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any state implementation plan approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48) of this chapter.

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of § 70.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 70.2 of this chapter.

(4) For the purposes of § 71.2 of this chapter, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in § 71.2 of this chapter.

Applicability of This Subpart

§ 62.16410 Am I subject to this subpart?

(a) You are subject to this subpart if you are the owner or operator of an affected electric generating unit (EGU) located within a State that has incorporated by reference this subpart as a State plan, or portion of a State plan, that has been approved by the Administrator and is effective under subpart UUUU of part 60 of this chapter, or if this subpart is promulgated and effective as a federal plan in your State under part 62 of this chapter.

(b) An affected EGU is any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter.

§ 62.16415 What are the requirements for retired affected EGUs?

(a) *Exemption.* (1) Any affected EGU that is permanently retired as defined in § 62.16570 is exempt from §§ 62.16420(c)(1) [CO_2 Emissions Requirements], 62.16535 [Compliance Requirements], 62.16540 [Monitoring], 62.16555 [Reporting], and 62.16560 [Recordkeeping].

(2) The exemption under paragraph (a)(1) of this section will become effective on the first day of the compliance period immediately following the compliance period in which the retirement took effect. Within 30 days of the affected EGU's permanent retirement, the designated representative must submit a statement to the Administrator. The statement must state, in a format prescribed by the Administrator, that the affected EGU was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) An affected EGU exempt under paragraph (a) of this section must not emit any CO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of an affected EGU exempt under paragraph (a) of this section must retain, at the affected EGU, records demonstrating that the affected EGU is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the affected EGU is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of an affected EGU exempt under paragraph (a) of this section must comply with the requirements of the CO_2 Rate-based Trading Program accruing during any compliance periods for which the exemption is not in effect, even if such requirements must be complied with after the exemption takes effect.

General Requirements

§ 62.16420 What emission standards and requirements must I comply with?

(a) *Designated representative requirements.* The owners and operators must have a designated representative, and may have an alternate designated representative, in accordance with §§ 62.16485 through 62.16495.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of affected EGU must comply with the monitoring, reporting, and recordkeeping requirements of §§ 62.16540, 62.16555, and 62.16560.

(2) The emissions data determined in accordance with § 62.16540 must be used to determine compliance with the CO_2 emission standard under paragraph (c) of this section, provided that, for each monitoring location from which emissions are reported, the emission rate used in determining compliance must be the CO_2 emission rate at the monitoring location determined in accordance with paragraph (c) of this section.

(c) *CO_2 emission standard requirements.* (1) Each designated representative for each affected EGU must demonstrate compliance with its emission standard listed in Table 1 of this subpart, as applicable, by calculating a CO_2 emission rate by factoring stack emissions and any emission rate credits (ERCs) into the following equation:

$$CO_2\text{emission rate} = \frac{\sum M_{CO2}}{\sum MWh_{op} + \sum MWh_{ERC}}$$

Where:

CO_2 emission rate = An affected EGU's calculated CO_2 emission rate that will be used to determine compliance with the applicable CO_2 emission standard.

M_{CO2} = Measured CO_2 mass in units of pounds (lbs) summed over the compliance period for an affected EGU.

MWh_{op} = Total net energy output over the compliance period for an affected EGU in units of MWh.

MWh_{ERC} = ERC replacement generation for an affected EGU in units of MWh (ERCs are denominated in whole integers as specified in paragraph (c)(2) of this section).

(2) An ERC qualifies for the compliance demonstration specified in paragraph (c)(1) of this section if it:

(i) Has a unique serial number;

(ii) Represents one whole MWh of actual energy generated or saved with zero associated carbon dioxide emissions;

(iii) Was issued to an eligible resource that meets the requirements of § 62.16435 or to an affected EGU that meets the requirements of § 62.16434, by the Administrator through an ERC tracking system or the ATCS; and

(iv) Was surrendered and retired only once for purposes of compliance with this regulation by the Administrator through an ERC tracking system or the ATCS.

(3) An ERC does not qualify for the compliance demonstration specified in paragraph (c)(1) of this section if it does not meet the requirements of paragraph (c)(2) of this section or if any State has used that same ERC for purposes of demonstrating achievement of its state measures.

(4) As of the ERC transfer deadline for a compliance period, the owners and operators of each affected EGU must hold, in the affected EGU's compliance account, sufficient ERCs to demonstrate compliance with its applicable emission standard listed in Table 1 of this subpart pursuant to the requirement of paragraph (c)(1) of this section.

(5) If an affected EGU exceeds its emission standard during a compliance period, then:

(i) The owners and operators of the affected EGU must hold ERCs required for deduction under § 62.16535(e);

(ii) The owners and operators of the affected EGU are subject to federal enforcement pursuant to sections 113(a)–(h), and section 304, of the Clean Air Act, and the United States, States, and other persons have the ability to enforce against violations (including if an affected EGU does not meet its emission standard based on its emissions, or use of ERCs that meet the compliance demonstration in § 62.16420 (c)(2)) and secure appropriate corrective actions, and the owners and operators must pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each day of such compliance period will constitute a separate violation of this subpart and the Clean Air Act;

(iii) If an affected EGU does not meet its emission standard because it did not meet the emissions standard based on its stack emissions and generation alone and it did not obtain sufficient qualifying ERCs to meet its emission standard by July 1 of the year following the relevant compliance period, then it may be subject to federal enforcement pursuant to Sections 113(a)–(h), 42 U.S.C. 7413(a)–(h), and Section 304 of the Clean Air Act, 42 U.S.C. 7604, and the United States, states, and other persons have the ability to enforce violations and secure corrective actions; and

(iv) If an affected EGU obtained sufficient facially valid ERCs to meet its emission standard, but those ERCs were found to be invalid, then it may be subject to federal enforcement as specified in paragraph (c)(5)(iii) of this section.

(d) *Compliance periods.* An affected EGU will be subject to the requirements under paragraph (c)(1) of this section for the compliance period starting on January 1, 2022, and for each compliance period thereafter.

(1) *Vintage of ERCs held for compliance.* An ERC held for compliance with the requirements under paragraph (c)(1) of this section for a compliance period must be an ERC that was issued for a year in such compliance period or for a year in a prior compliance period.

(2) *ATCS.* Each ERC must be held in, deducted from, transferred into, out of, or between ATCS accounts in accordance with this subpart.

(3) *Limited authorization.* (i) An ERC shall only be used in accordance with the CO_2 Rate-based Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(4) *Property right.* An ERC does not constitute a property right.

(e) *Title V permit requirements.* (1) Unless otherwise specified in this paragraph, all requirements of this subpart shall be applicable requirements that must be included in an affected EGU's title V permit.

(2) The applicable requirements of this subpart, as well as other terms or conditions necessary to ensure compliance with the applicable requirements, may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that such changes do not conflict with any existing terms of the permit. This paragraph explicitly provides that the addition of, or change to, an affected EGU's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(3) No title V permit revision will be required for any crediting, holding, deduction, or transfer of ERCs in accordance with this subpart, provided that the requirements applicable to such creditings, holdings, deductions, or transfers of ERCs are already incorporated in such permit.

(f) *Liability.* Any provision of the CO_2 Rate-based Trading Program that applies to an affected EGU or the designated representative of an affected EGU shall also apply to the owners and operators of such affected EGU.

(g) *Effect on other authorities.* No provision of the CO_2 Rate-based Trading Program or exemption under § 62.16415 shall be construed as exempting or excluding the owners and operators, and the designated representative, of an affected EGU from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or any other requirement of the Clean Air Act.

§ 62.16425 How should I compute time under the CO_2 Rate-based Trading Program?

(a) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CO_2 Rate-Based Trading Program, to begin before the occurrence of an act or event will be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CO_2 Rate-Based Trading Program, is not a business day, then the time period will be extended to the next business day.

§ 62.16430 What are the administrative appeal procedures?

The administrative appeal procedures for decisions of the Administrator under the CO_2 Rate-based Trading Program are set forth in part 78 of this chapter.

§ 62.16431 How will the Clean Energy Incentive Program be administered under the federal plan?

(a)(1) The Administrator will participate in the Clean Energy Incentive Program, established under subpart UUUU of part 60 of this chapter, on behalf of any state for whom this subpart is promulgated as a federal plan under section 111(d) of the Act. The Administrator will award, on behalf of each such state, early action ERCs for generation and savings achieved in 2020 and/or 2021 that result from the following types of eligible renewable energy (RE) and demand-side energy efficiency (EE) projects:

(i) Metered wind power;

(ii) Metered solar power; and

(iii) Demand-side EE implemented in a low-income community.

(2) Eligible RE projects must commence construction, and eligible demand-side EE projects must commence implementation, after September 6, 2018 for those states on whose behalf the EPA is implementing the federal plan. Eligible projects must be located in or benefit the state on whose behalf the EPA is implementing the federal plan.

(b) Early action ERCs will be distributed pursuant to a process to be prescribed by the Administrator, and in a manner to be demonstrated by the Administrator to have no impact on the aggregate emission performance of affected EGUs required to meet rate-based emission standards during the compliance periods.

(c) The Administrator will match these early action ERCs with additional matching ERCs pursuant to a process to be prescribed by the Administrator. Matching awards will be made up to a limit equivalent to the state's pro rata share of 300 million short tons of CO_2 emissions.

(d) The awards, including the matching award, will be executed as follows:

(1) For RE projects that generate metered MWh from wind or solar resources: For every two MWh generated, the project will receive one early action ERC under paragraph (b) of this section and one matching ERC from the match under paragraph (c) of this section; and

(2) For EE projects that benefit low-income communities as determined by the Administrator solely for purposes of this subpart: For every two MWh in end-use demand savings achieved, the project will receive two early action ERCs under paragraph (b) of this section and two matching ERCs from the match under paragraph (c) of this section.

Emission Rate Credit Issuance, Adjustment, and Revocation

§ 62.16434 What affected EGUs qualify for generation of ERCs?

(a) ERCs may only be issued to affected EGUs under the conditions listed in paragraphs (b) and (c) of this section.

(b) For affected EGUs that emit below their applicable emission standard, the amount of ERCs generated must be calculated using the following equation:

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

Where:

ERCs = Number of emission rate credits generated by an affected EGU during an applicable compliance period (MWh).

EGU emission standard = The emission standard the affected EGU must comply with during the applicable compliance period according to § 62.16420 (lb/MWh).

EGU emission rate = The affected EGU's measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).

EGU generation = Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with § 62.16540 (MWh).

(c) Stationary combustion turbines that meet the definition of an affected EGU may generate net energy output MWh gas shift ERCs (GS–ERCs) for all hours of operation during a given compliance period according to paragraphs (c)(1) through (3) of this section.

(1) To calculate the number of GS–ERCs:

GS–ERCs = EGU Generation * Incremental Generation Factor * GS–ERC Emission Factor

Where:

GS–ERC = Net energy output MWh gas shift ERCs.

EGU generation = Total net energy output generation of the affected EGU during the applicable compliance period measured in accordance with § 62.16540 (MWh).

Incremental Generation Factor = See Table 2 of this subpart for the applicable factor for each compliance period.

GS–ERC Emission Factor = Value calculated using equation (c)(2) of this section.

(2) To calculate the GS–ERC Emission factor for your specific affected EGU you must use the following equation:

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

Where:

GS–ERC Emission Factor = Factor to be used in the equation in paragraph (c)(1) of this section for GS–ERC calculation.

EGU emission rate = Affected EGU's measured CO_2 emission rate measured in accordance with § 62.16540 (lb/MWh).

Steam turbine emission standard = Steam turbine emission standard for the corresponding compliance period as found in Table 1 of this subpart (lb/MWh).

(3) Notwithstanding any other provision of this subpart, GS–ERCs must not be used for compliance by an affected EGU that is a stationary combustion turbine. Stationary combustion turbines may use other ERCs in their compliance demonstration.

§ 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs?

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

(1) Resources qualifying for eligibility only include resources which increased new installed electrical generation nameplate capacity, or new electrical savings measures installed or implemented after January 1, 2013. If a resource had a nameplate capacity uprate, then ERCs may be issued only for the difference in generation between the uprated nameplate capacity and its nameplate capacity prior to the uprate. ERCs must not be issued for generation for an uprate that followed a derate that occurred on or after January 1, 2013. A resource that is relicensed or receives a license extension is considered existing

capacity and is not an eligible resource, unless it receives a capacity uprate as a result of the relicensing process that is reflected in its relicensed permit. In such a case, only the difference in nameplate capacity between its relicensed permit and its prior permit is eligible to be issued ERCs.

(2) The resource must be connected to, and delivers energy to or saves electricity, on the electric grid in the contiguous United States.

(3) The resource is located in a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation, unless the resource is located in a State with mass-based emission standards and the resource can demonstrate (*e.g.,* through a power purchase agreement or contract for delivery) transmission of its generation into a State whose affected EGUs are subject to rate-based emission standards pursuant to this regulation.

(4) The resource falls into one of the following categories of resources:

(i) Renewable electric generating technologies using one of the following renewable energy resources: wind, solar, geothermal, hydro, wave, tidal;

(ii) Qualified biomass;

(iii) Waste-to-energy (biogenic portion);

(iv) Nuclear energy;

(v) A non-affected combined heat and power unit, including waste heat power; or

(vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex poste savings, not ''projected'' or ''claimed'' savings.

(b) Any resource that does not meet the requirements of this subpart cannot generate ERCs for use in the compliance demonstration required under § 62.16420.

(c) ERCs may not be issued to any of the following:

(1) New, modified, or reconstructed EGUs that are subject to subpart TTTT of part 60 of this chapter, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(2) EGUs that do not meet the applicability requirements of § 62.16410, except CHP units that meet the requirements of a CHP unit under paragraph (a) of this section;

(3) Measures that reduce CO_2 emissions outside the electric power sector, including GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors, direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification; and

(4) Any measure not approved by the EPA to generate ERCs in connection with a specific State plan.

§ 62.16440 What is the process for revocation of qualification status of an eligible resource?

(a) If an eligible resource is found to not meet the requirements of § 62.16435 in the Rate-based Trading Program, then the Administrator will revoke the eligibility of the eligible resource to be issued ERCs. In addition, the provisions of § 62.16450(d) may apply.

(b) Any instance of intentional misrepresentation in an eligibility application or monitoring and verification (M&V) report may be cause for revocation of the qualification status of an eligible resource.

(c) Repeated instances of error or misstatement of MWh of electricity generation or savings in submitted M&V reports, or in any other submissions may be cause for the Administrator to revoke the eligibility of an eligible resource to be issued ERCs.

(d) In the event of an intentional misrepresentation, or repeated instances of error or misstatement, in program submissions, by the authorized account representative of the eligible resource, the Administrator may prohibit the eligible resource from any further eligibility to be issued ERCs. In addition, the provisions of § 62.16450 (a) through (d) may apply.

§ 62.16445 What is the process for the issuance of ERCs?

The process and requirements for issuance of ERCs for affected EGUs and eligible resources are set forth in paragraphs (a) through (f) of this section.

(a) *Eligibility application.* To receive ERCs, an authorized account representative of an eligible resource must submit an eligibility application to the Administrator that demonstrates that the requirements of § 62.16434 (for an affected EGU) or § 62.16435 (for an eligible resource) are met, and, in the case of an eligible resource only, demonstrates that the requirements in paragraphs (a)(1) through (9) of this section are met.

(1) Identification of the authorized account representative of the eligible resource, including the authorized account representative's name, address, email address, telephone number, and ERC tracking system account number.

(2) Identification of the eligible resource(s), including the information in paragraphs (a)(2)(i) through (v) of this section.

(i) For an eligible resource, the physical location of the eligible resource; contact information for the owner or operator of the eligible resource, if different from the designated representative or authorized account representative; eligible resource generator prime mover and/or technology type; eligible resource nameplate capacity; eligible resource category (*e.g.,* wholesale generator, wholesale generator also serving onsite customer load, customer-sited distributed generator) (if applicable); facility and generating unit IDs (EIA ORIS Code, Facility Registration System (FRS) Code, if applicable); for the eligible resource, the control area, balancing authority, ISO conditions as defined in § 62.16570, or the regional transmission organization in which the generator is located (if applicable).

(A) For an eligible resource with a nameplate capacity of1 MW or more, a copy of the most recent filing of a copy of the generating facility's U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860.

(B) For an electric generating resource with a nameplate capacity of less than 1 MW, the information that would be contained in U.S. Energy Information Agency's Annual Electric Generator Report Form EIA–860, if that electric generating facility had nameplate capacity of 1 MW or more.

(ii) For an energy-saving resource that is project-based, a detailed description of the demand-side EE or electricity savings project, including: Location and specifications of the building(s), facility(ies), or installations where energy-saving measures were implemented or will be implemented; owner and operator of the building(s), facility(ies), or installations where the energy-saving measures are implemented or will be implemented; the parties implementing the energy-saving project, including lead contractor(s), subcontractors, and consulting firms (if different from the authorized account representative); energy-saving measures installed and/or energy-savings practices implemented (or to be installed/implemented); specifications of equipment and materials installed, or to be installed, as part of the energy-saving project; project plans and technical schematics, as applicable.

(iii) For an energy-savings resource that involves an EE requirement or program, a description of the electricity savings program, including: Overall approach or ''logic'' to the requirement or program, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or installations where energy-saving requirements or programs were implemented or will be implemented; electricity consuming system(s), end-use(s), building or facility type(s), or installations where the energy-saving requirements or programs are implemented or will be implemented; the parties implementing the energy-saving requirement or program, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of energy-saving equipment and/or energy-savings practices implemented (or to be installed/implemented) under the requirement or program; the delivery mechanisms of the requirement or program, which may include financial incentives or equipment rebates, dissemination of actionable information to electricity customers, on-site audits paired with technical recommendations.

(iv) For other electricity-saving resources (*e.g.,* transmission and distribution (T&D) measures such as conservation voltage reduction (CVR)), a description of the resource, including: Overall approach or ''logic'' to the electricity-saving resource, including applicable strategies and activities, along with key assumptions regarding how such strategies and activities will achieve quantifiable reductions in electricity consumption; location and geographic distribution of the targeted building(s), facility(ies), or electricity transmitting and distributing systems, as applicable, where electricity-saving resources were implemented or will be implemented; electricity consuming, transmitting, or distributing system(s), building or facility type(s), or end-use(s) where the electricity-saving resource are implemented or will be implemented; the parties implementing the electricity-saving resource, including lead contractor(s), subcontractor(s), and consulting firms (if different from the authorized account representative); specifications of installed equipment and/or implemented practices (or to be installed/implemented); the delivery mechanisms used to implement and propagate the electricity-saving resource, as applicable.

(v) For eligible resources with distributed locations, such as measures at multiple residential, commercial, or industrial buildings, at a minimum, aggregated information about the location of measures that constitute an eligible resource, provided that the accredited independent verifier and the Administrator have the ability to access information specifying the location of each discrete measure that constitutes an eligible resource.

(3) Demonstration that the eligible resource meets all applicable eligibility requirements in § 62.1435.

(4) A certification that the eligibility application has only been submitted to the Administrator or pursuant to an EPA-approved multi-state approach where States are providing for joint issuance of ERCs pursuant to the authority in their individual State plans.

(5) An evaluation measurement and verification (EM&V) plan.

(6) A verification report from an accredited independent verifier who meets the requirements of §§ 62.16470 and 62.16475.

(7) An authorization that provides for the following: The Administrator may inspect (including a physical inspection of the eligible resource and its meter) and/or audit the eligible resource at any time and verify that the eligible resource and the EM&V plan have been implemented as described in the eligibility application.

(8) The following statement, signed by the designated representative of the eligible resource:

(i) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(ii) [Reserved]

(9) Any other information required by the Administrator.

(b) *Registration of eligible resources.* The Administrator must review the eligibility application to determine whether the affected EGU or eligible resource meets the requirements of § paragraph (a) of this section, and if it determines that the requirements are met, approve the eligibility application and register the affected EGU or eligible resource in an ERC tracking system that meets the requirements of § 62.16515. Once so registered, the affected EGU or eligible resource is eligible to be issued ERCs, provided all other applicable requirements continue to be met.

(c) *M&V reports.* For an eligible resource, the designated representative must submit to the Administrator an M&V report prior to issuance of ERCs by the Administrator.

(d) *Verification reports.* For an eligible resource, the authorized account representative must submit a verification report from an accredited independent verifier that meets the requirements of §§ 62.16470 and 62.16475 as part of each eligibility application and M&V report. While considered a part of the eligibility application and M&V report, the verification report must be submitted separately by the accredited independent verifier to the Administrator.

(e) *Issuance of ERCs.* ERCs may only be issued by the Administrator based on actual electricity generation or savings documented in an M&V report that meets the requirements of § 62.16460 and a verification report that meets the requirements of § 62.16465. Only one ERC will be issued for each verified MWh.

(f) *Tracking system.* ERCs may only be issued through an ERC tracking system that meets the requirements of § 62.16515.

§ 62.16450 What is the process for error adjustments or misstatement, and suspension of ERC issuance?

(a) In the event of error or misstatement of quantified MWh of electricity generation or savings in a previous M&V report for which ERCs have been issued, the Administrator may adjust the number of ERCs issued in a subsequent reporting period to address the error or misstatement, by subtracting a number of MWh from the quantified and verified MWh in the M&V report for the subsequent reporting period. In the event that an error or inadvertent misstatement occurs in a final M&V report for an eligible resource, for which ERCs have been issued, the provisions of paragraph (b) of this section will apply.

(b) In the event of error or misstatement of quantified MWh of electricity generation or savings in the final M&V report for an eligible resource, for which ERCs have been issued, the Administrator will revoke ERCs from the general account held by the authorized account representative of the eligible resource, in an amount necessary to correct the error or misstatement. In the event that the general account of the eligible resource holds an insufficient number of ERCs to correct the error or misstatement, the authorized account representative must submit to the Administrator within 30 days a number of ERCs necessary to correct the error or misstatement. Failure to meet this requirement will result in prohibition of the authorized account representative for the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(c) The Administrator may freeze the general account held by an authorized account representative of an eligible resource at any time, for cause, if the Administrator determines ERCs have been improperly issued, based on a misrepresentation or misstatement in an eligibility application or M&V report. The Administrator may also freeze the general account of an authorized account representative of an eligible resource pending investigation of potential misrepresentation, error, or misstatement in an eligibility application of an eligible resource, or in an M&V report for which ERCs have been issued. Freezing a general account will prevent transfer of ERCs out of the account.

(d) If ERCs are issued for an eligible resource that is found to be ineligible, then the Administrator may take the actions in paragraphs (d)(1) through (3) of this section.

(1) Freeze the general account for the eligible resource, preventing any transfers of ERCs out of the account.

(2) Revoke and deduct ERCs held in the general account of the authorized account representative for an eligible resource, in a number equal to the number of ERCs issued for the ineligible eligible resource.

(3) In the event that the general account of the eligible resource holds a number of ERCs less than the number of ERCs issued for the ineligible eligible resource, the delegated representative of an eligible resource must submit to the Administrator within 30 days a number of ERCs necessary to fully account for all ERCs issued for the ineligible eligible resource. Failure to meet this requirement will result in prohibition of the eligible resource from further participation in the program, unless reauthorized at the discretion of the Administrator.

(e) The Administrator may temporarily or permanently suspend issuance of ERCs for an eligible resource, for the following reasons in paragraphs (e)(1) through (3) of this section.

(1) Pending investigation of potential misrepresentation, error, or misstatement in an M&V report, for which ERCs have been issued, or the eligibility status of an eligible resource.

(2) In the case of repeated error or misstatements in submitted M&V reports.

(3) In the case of an intentional misrepresentation in a submitted M&V report.

Evaluation Measurement and Verification Plans, Monitoring and Verification Reports, and Verification

§ 62.16455 What are the requirements for evaluation measurement and verification plans for eligible resources?

(a) *EM&V plan requirements.* Any EM&V plan submitted in support of the issuance of an ERC pursuant to this rule must meet the requirements of this section.

(b) *General EM&V plan criteria.* Each EM&V plan must identify the eligible resource and its approved eligibility application.

(c) *Specific EM&V plan criteria.* Each EM&V plan must provide the manner in which the electricity generated or saved by the eligible resource will be quantified, monitored and verified, and the manner of quantification, monitoring and verification must meet the criteria listed in paragraphs (c)(1) through (7) of this section, as applicable to the specific eligible resource.

(1) For a nuclear energy resource or a renewable energy resource with a nameplate capacity of 10 kW or more and for a renewable energy resource with a nameplate capacity of less than 10 kW for which metered data are available, each EM&V plan must specify that the requirements in paragraphs (c)(1)(i) through (vi) of this section are met.

(i) The generation data are physically measured on a continuous basis using a revenue-quality meter, which means a meter used by a control area operator for financial settlements, or a meter that meets the American National Standards Institute No. C12.20., Code for Electricity Metering, metering accuracy standards, or a meter that meets an alternative equivalent standard that has been approved in advance of its use to measure generation pursuant to this regulation by the EPA.

(ii) The generating data are measured at the generator's bus bar, or, for a renewable energy resource with a nameplate capacity of less than 10 kW that is interconnected behind an individual business or household meter, the generating data were measured at the AC output of the inverter and adjusted to reflect the only energy delivered into either the transmission or distribution grid at the generator bus bar and not any energy used on-site at the generator.

(iii) The generation data from only one eligible resource generating unit may be associated with each meter, and generation data may not be aggregated, unless all the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same type of meter that is subject to the same maintenance and quality assurance procedures.

(iv) The generation data are collected electronically and telemetered from the generator to its control area operator and verified through a control area energy accounting or settlement process which occurs at least monthly, unless the generation unit does not go through a control area operator, in which case the generation data must be collected by manual meter readings conducted by an independent verifier that is either not affiliated with the owner or operator of the qualifying renewable energy generating resource or is precluded pursuant to the relevant State plan from the ability to transfer or retire ERCs issued to that qualifying renewable energy generating resource or, if the generating unit is less than 10 kw and does not generate enough electricity to enable monthly reporting, then the data may be self-reported and reported no less than annually.

(v) The generation data serve a load that otherwise would have been served by the grid if not for the generator. Specifically:

(A) ERCs shall not be issued for energy generation used to supply the ancillary equipment used to operate a generating station or substation (''station service'') or parasitic load on the generator's side of the point of interconnection; and

(B) For generators interconnected to transmission systems and with on-site loads other than station service drawing generation before the metering point, ERCs may be issued for on-site load, if the owner or operator of the eligible resource can demonstrate that the metering used is capable of distinguishing between on-site load and station service.

(vi) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(2) For a renewable energy resource with a nameplate capacity of less than 10 kW and that does not have a meter, each EM&V plan must require that the following requirements in paragraphs (c)(2)(i) though (vii) of this section are met.

(i) Metered data are unavailable.

(ii) At least 1 MW of net energy output is generated to the distribution or transmission system over a continuous 365-day period.

(iii) The generation data may not be aggregated, unless the following provisions are met:

(A) All of the generating units have the same essential generation characteristics;

(B) All of the generating units are located in the same State;

(C) The nameplate capacity of the individual units being aggregated is each less than 150 kW, and units collectively do not exceed a total nameplate capacity of 1 MW when aggregated, or alternative requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan or M&V report is submitted; and

(D) The generation data are measured by the same generation estimating software or algorithms.

(iv) The generation data are measured on at least a monthly basis using generation estimating software or algorithms that are based on an on-site inspection prior to interconnection and a resource study (wind, shading, solar irradiance, depending on the resource), or engineering information that takes into account the capacity, age, and type of qualifying energy generating resource, and all input parameters and assumptions must be clearly delineated, or if the generating unit does not generate enough electricity to enable monthly reporting, then the data may be reported no less than annually.

(v) The generation data are self-reported to the distribution utility through an electronic internet-based portal with software that reports total and hourly generation.

(vi) The generation data serve a load that otherwise would have been served by the grid if not for the generator. The ERC is only based on generation transferred from the eligible resource to the transmission or distribution grid, and is not based on the generation used on-site by the customer.

(vii) Any other requirements approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted.

(3) For qualified biomass feedstocks used, in addition to the requirements of paragraphs (c)(1) or (2) of this section, whichever section is applicable, each EM&V plan must demonstrate that the requirements approved by the EPA for that biomass feedstock, and its associated biogenic CO_2, have been met.

(4) For a waste-to-energy resource, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must specify:

(i) The total net energy generation from the resource in MWh;

(ii) The method for determining the specific portion of the total net energy output from the resource that is related to the biogenic portion of the waste materials; and

(iii) The net energy output measured with the relevant method approved by the EPA in connection with the specific State plan pursuant to which that EM&V plan is submitted demonstrates that the requirements approved by the EPA in connection with that State plan have been met.

(5) For a combined heat and power unit, in addition to the requirements of paragraphs (c)(1) or (2) of this section, as applicable, and paragraph (c)(3) of this section, each EM&V plan must meet one of the requirements in paragraphs (c)(5)(i) through (iv) of this section, as applicable, and any other requirements approved by the EPA.

(i) If the combined heat and power unit has an electric generating capacity greater than 25 MW, then the EM&V plan must meet the requirements that apply to an affected EGU under § 62.16540.

(ii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iii) If the combined heat and power unit has an electric generating capacity less than or equal to 25 MW and greater than 1 MW, and it uses anything other than only natural gas and/or distillate fuel oil, then the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in part 75 of this chapter.

(iv) If the combined heat and power unit has an electric generating capacity less than or equal to 1 MW the unit must keep monthly cumulative recordings of useful thermal output and fossil fuel input along with the determination of baseline thermal source efficiencies based on manufacturer data. For CHP units that directly serve on-site end-use electricity loads, avoided T&D system losses can be assessed as is commonly practiced with demand-side EE.

(6) For demand-side electricity savings that avoid a transmission and distribution loss, each EM&V plan must measure the transmission and distribution loss based on the lesser of 6 percent of the facility- or premises-level electricity savings measured at the electricity customer's meter, or the statewide annual average transmission and distribution loss rate (expressed as a percentage) from the most recent year that is published in the US EIA State Electricity Profile. No other transmission and distribution loss factors may be used in calculating the electricity savings.

(7) Each EM&V plan for an EE program, EE project, or EE measure must specify how each of the requirements in paragraphs (c)(7)(i) through (x) of this section will be met in quantifying the electricity savings from that EE program, EE project, or EE measure.

(i) All electricity savings must be quantified on an ex-post basis, which means after the electricity savings have occurred, or on a real-time basis, which means at the time the electricity savings are occurring. Electricity savings must not be quantified on an ex-ante basis, which means estimates of MWh savings that are generated prior to implementing the subject EE program, EE project, or EE measure, and that are not quantified using EM&V methods and procedures.

(ii) All electricity savings must be quantified and verified based on methods and procedures detailed in an industry best-practice EM&V protocol or guideline. Each EM&V plan must include a demonstration of how the best-practice protocol or guideline was selected and will be applied to the specific EE program, EE project, or EE measure covered in the EM&V plan, and an explanation of why that particular protocol or guideline was selected. Protocols and guidelines are considered to be best practice if they:

(A) Have gone through a rigorous and credible peer review process that shows the applicable methods to be valid through empirical testing; and

(B) Have been accepted and approved for use by identifiable state regulatory commissions. Examples of such protocols and guidelines that may be provided in EM&V guidance issued by the Administrator will be acceptable.

(iii) All electricity savings must be quantified as the difference between the observed electricity use and a common practice baseline (CPB), which is the equipment that would typically have been installed—or that a typical consumer or building owner would have continued using—in a given circumstance (*i.e.,* a given building type, EE program type or delivery mechanism, and geographic region) at the time of EE implementation. Examples of CPBs for specific EE programs, EE projects, EE measures, and for certain EM&V methods that may be provided in EM&V guidance issued by the Administrator will be acceptable. The EM&V plan must specify the reason the specific CPB was selected, which must include an analysis of the appropriateness of that CPB for the EE program, EE project, or EE measure covered in the EM&V plan, based on:

(A) Characteristics of the EE program, EE project, or EE measure;

(B) The delivery mechanism used to implement the EE program, EE project, or EE measure (*e.g.,* installed as part of a utility EE program versus a point-of-sale rebate);

(C) Local consumer and market characteristics;

(D) Applicable building energy codes and standards and average compliance rates; and

(E) The method applied: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(iv) All electricity savings must be quantified by applying one or more of the following methods: Project-based measurement and verification (PB–MV), comparison group approaches, or deemed savings.

(A) If a comparison group approach is used, then the EM&V plan must quantify electricity savings by taking the difference between a comparison group's electricity use and the electricity use of EE program participants. Comparison group approaches may include randomized control trials and quasi-experimental methods, as described in industry best-practice protocols and guidelines. Examples of such protocols and guidelines provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(B) If deemed savings are used, then the EM&V plan must specify that the deemed savings values will only be used for the specific EE measure for which they were derived. The EM&V plan must also specify the name and Web address of the technical reference manual (TRM) in which all deemed electricity savings values will be documented. Prior to use in an EM&V plan, all TRMs must undergo a review process in which the public, stakeholders, and experts are invited—with adequate advance notification (via the internet and other social media)—to provide comment, have at least 2 months to provide comment, and in which all such comments and associated responses are made publicly available. All TRMs must also be publicly accessible over the full period of time in which they are being used in conjunction with an EM&V plan for the purpose of quantifying savings, and must be subsequently updated in the same manner at least every 3 years. The TRM must indicate, for each subject EE measure, the associated electricity savings value, the conditions under which the value can be applied (including the climate zone, building type, manner of implementation, applicable end uses, operating conditions, and effective useful life), and the manner in which the electricity savings value was quantified, which must include applicable engineering algorithms, source documentation, specific assumptions, and other relevant data to support the quantification of savings from the subject EE measure.

(v) All EE programs, EE projects, or EE measures must be quantified at time intervals (in years) sufficient to ensure that MWh savings are accurately and reliably quantified. Such time intervals must be specified and explained in the EM&V plan. Factors that must be taken into consideration when determining the appropriate time interval include the characteristics of the specific EE program, EE project, or EE measure, expected variability in electricity savings (where greater variability necessitates more frequent quantification), the expected scale and magnitude of the electricity savings (where greater quantities of savings necessitate more frequent quantification), and the experience implementing and quantifying savings from the resource (where less experience—for example, with new and innovative EE program types—necessitates more frequent quantification). The time intervals must end no sooner than the last day of the effective useful life of the EE program, EE project, or EE measure, and must last no longer than:

(A) Every 4-year intervals for building energy codes and product standards;

(B) Every 1, 2, or 3 years for public or consumer-funded EE program, EE project, or EE measure, as relevant for the type of EE program, EE project, or EE measure and factors listed in paragraph (c)(7)(v) of this section; and

(C) Annually for commercial and industrial projects, unless the resource provider can provide a reasonable justification in the EM&V plan for why an annual time interval is not feasible, and can additionally explain how the accuracy and reliability of savings values will not be lessened.

(vi) EM&V plans must specify and document how the EM&V components in paragraphs (c)(7)(vi)(A) through (E) of this section will be analyzed, considered, or otherwise addressed in the quantification and verification of electricity savings.

(A) The effects of changes in independent factors on reported electricity savings (*i.e.,* factors that are not directly related to the EE measure, such as weather, occupancy, and production levels).

(B) The effective useful life (EUL) or duration of time the EE measure is anticipated to remain in place and operable with the potential to save electricity, which must be based on the application of EM&V methods, an industry best-practice persistence study, deemed estimates of effective useful life, or a combination of all three.

(1) If deemed estimates of effective useful life are used, then they must specify the date by which the EE measure will stop saving electricity.

(2) If industry best-practices persistence studies are used to modify an effective-useful-life value, then they must be conducted at least every 5 years.

(C) The potential sources of double counting, and the associated steps for avoiding and correcting for it, such as:

(1) For an EE program or EE project with identified participants, track the type and number of EE measures implemented at the utility-customer level.

(2) For an EE program or EE project without identified participants, such as point-of-sale rebates and retailer or manufacturer incentive programs, track applicable vendor, retailer, and manufacturer data.

(3) For EE programs (such as those implemented by a utility) and EE projects (such as those implemented by an energy service company) that both have identified participants, use tracking data to avoid and correct for double counting that may occur across the two; and

(4) For EE programs with identified participants and those without (such as retail incentives to purchase energy-efficient equipment), use EE program tracking data for the former and use applicable vendor, retailer, and manufacturer data for the latter to avoid and correct for double counting that may occur across the two.

(D) The EE savings verification approaches for ensuring that EE measures have been properly installed, are operating as intended, and therefore have the potential to save electricity, including how verification will be carried out within the first year of implementation of the EE program, EE project, or EE measure using best-practice approaches, such as physical inspections at a customer's premises, phone and mail surveys, and reviews of sales receipts and other documentation. If such approaches are documented in EM&V guidance issued by the Administrator, they will be treated as acceptable.

(E) The interactive effects of EE programs, EE projects, or EE measures on electricity usage, which are increases or decreases in electricity usage at an end-use facility or premises that occurs outside of specific end-uses(s) targeted by the EE program, EE project, or EE measure (*e.g.,* lighting retrofits to improve EE can reduce waste heat to the surrounding conditioned space, and therefore may increase the required electric heating load in a facility or premises).

(vii) The EM&V plan must specify how the accuracy and reliability of the electricity savings of the EE program, EE project, or EE measure will be assessed, and must discuss the rigor of the method selected to quantify the electricity savings. It must also discuss the approaches that will be used to control all relevant types of bias and to minimize the potential for systematic and random error, as well as the program- or project-specific circumstances in which such bias and error are likely to arise. Approaches to minimizing bias and error are provided in the EM&V guidance that may be issued by the Administrator will be acceptable.

(viii) If sampling will be used to quantify the electricity savings from an EE program, then the MWh estimates derived from sampling must have at least 90 percent confidence intervals whose end points are no more than ±10 percent of the estimate, and the statistical precision of the associated estimates must be specified in the EM&V plan.

(ix) All data sources and key assumptions used to quantify electricity savings must be described in the EM&V plan.

(x) Any additional information necessary to demonstrate that the electricity savings were appropriately quantified and verified. Approaches to quantifying and verifying savings from several EE program and EE project types that are provided in EM&V guidance that may be issued by the Administrator will be acceptable.

(d) You must ensure that any EM&V plan submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16460 What are the requirements for monitoring and verification reports for eligible resources?

(a) *M&V report requirements.* Any M&V report that is submitted, in support of the issuance of an ERC that can be used in accordance with § 62.16420, must meet the requirements of this section.

(b) *General M&V report criteria.* Each M&V report must include the following:

(1) For the first M&V report submitted, documentation that the electricity-generating resources, electricity-saving measures, or practices were installed or implemented consistent with the description in the approved eligibility application required in § 62.16445(a); and

(2) For each M&V report submitted:

(i) Identification of the time period covered by the M&V report;

(ii) A description of how relevant quantification methods, protocols, guidelines, and guidance specified in the EM&V plan were applied during the reporting period to generate the quantified MWh of generation or MWh of electricity savings;

(iii) Documentation (including data) of the energy generation and/or electricity savings from any activity, project, measure, resource, or program addressed in the EM&V report, quantified and verified in MWh for the period covered by the M&V report, in accordance with its EM&V plan, and based on ex-post energy generation or savings;

(iv) Documentation of any change in the energy generation or savings capability of the eligible resource during the period covered by the M&V report and the date on which the change occurred, and either certification that the eligible resource continued to meet all eligibility requirements during the reporting period covered by the M&V report or disclosure of any material changes to the eligible resource from the description of the eligible resource in the approved eligibility application, which must include any change in the energy generation (*e.g.,* nameplate MW capacity) or electricity savings capability of the qualifying eligible resource (including the date of the change); and

(v) Documentation of any change in ownership interest of the qualifying eligible resource (including the date of the change).

(c) You must ensure that any M&V report submitted pursuant to this subpart includes the following certification:

(1) ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) [Reserved]

§ 62.16465 What are the requirements for verification reports?

(a) A verification report included as part of an eligibility application or an M&V report must meet the requirements of paragraph (b) of this section (for the eligibility application verification report) and paragraph (c) of this section (for the M&V report verification report) and include the following:

(1) A verification statement that sets forth the findings of the accredited independent verifier, based on the verifier's assessment of the information and data in the eligibility application or M&V report that is the subject of the verification report, including an assessment of whether the eligibility application or M&V report contains any material misstatements or material data discrepancies, and whether the submittal conforms with applicable regulatory requirements. The verification statement must clearly identify how levels of assurance and materiality are defined as part of the verifier assessment.

(2) The following statement, signed by the accredited independent verifier: ''I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my personal knowledge and/or inquiry of those individuals with primary responsibility

for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) A verification report included as part of an eligibility application must, at a minimum, describe the review conducted by the accredited independent verifier and verify each of the following:

(1) The eligibility of the eligible resource to be issued ERCs pursuant to this regulation, in accordance with § 62.16435 and § 62.16445(a), including an analysis of the adequacy and validity of the information submitted by the authorized account representative to demonstrate that the eligible resource meets each applicable requirement of § 62.16435 and § 62.16445(a).

(2) The eligible resource is not duplicative of a resource used to meet emission standards or a state measure in another approved State plan.

(3) The eligible resource exists or the practice or activity will be implemented in the manner specified in the eligibility application.

(4) The EM&V plan meets the requirements of § 62.16455.

(5) Disclosure of any mandatory or voluntary programs to which data is reported relating to the eligible resource (*e.g.,* reporting of electric generation by a renewable energy resource to a renewable energy certificate tracking system).

(6) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

(c) A verification report included as part of a M&V report must, at a minimum, describe the review conducted by the accredited independent verifier and verify the following:

(1) The adequacy and validity of the information and data submitted in the submittal by the authorized account representative to quantify eligible MWh of electric generation or electricity savings during the period for which the authorized account representative seeks issuance of ERCs, as well as all supporting information and data identified in the EM&V plan and M&V report. This analysis must include a quality assurance and quality control check of the data and ensure that all generation or savings data are within a technically feasible range for that specific eligible resource.

(i) For metered generation, the data validity check must compare reported electricity generation to an engineering estimate of the maximum generation potential of the qualified renewable energy resource, based on, at a minimum, its maximum nameplate capacity in MW and the number of days since the prior cumulative meter reading was entered in the ERC tracking system. If the data entered exceed the estimated technically feasible generation, then the reported data and the estimate must be analyzed in the verification report.

(ii) For all electricity generated or saved, the accredited independent verifier must describe the likely source of any data discrepancy and determine in the verification report any MWh generated or saved.

(2) The M&V report meets the requirements of § 62.16460.

(3) Any other information required by the Administrator or that the accredited independent verifier finds, in its professional opinion, is necessary to assess the adequacy and validity of information and data supplied by the authorized account representative.

§ 62.16470 What is the accreditation procedure for independent verifiers?

(a) Only Administrator-accredited independent verifiers may provide a verification report for an eligibility application or M&V report.

(b) Applications for accreditation must follow a procedure and form specified by the Administrator which includes a demonstration by the verifier that it meets the requirements in paragraph (c) of this section.

(c) Independent verifiers must meet each of the requirements in paragraphs (c)(1) through (6) of this section to be accredited.

(1) Independent verifiers must have the skills, experience, and resources (personnel and otherwise) to provide verification reports, including the following:

(i) Appropriate technical qualification (professional engineer or otherwise) to evaluate the eligible resource for which the independent verifier is seeking accreditation, which may include ANSI accreditation under ISO 14065 for GHG validation and verification bodies;

(ii) Appropriate auditing and accounting qualifications for financial and non-financial data monitoring, auditing, and quality assurance and quality control to evaluate the eligible resource for which the independent verifier is seeking accreditation;

(iii) Knowledge of the requirements of the Administrator's CO_2 Rate-based Trading Program regulations and related guidance;

(iv) Knowledge of the eligible resource categories for which the independent verifier is seeking accreditation, including relevant aspects of the design, operation, and related energy generation or electricity savings monitoring and reporting approaches for such eligible resources; and

(v) Capability to perform key verification activities, such as development of a verification report; performance of site visits; review and recalculation of reported data; review of data management systems; review of quantification methods used in accordance with an approved EM&V plan; preparation of a verification statement, list of findings, and verification report; and internal review of the verification findings and report.

(2) Independent verifiers must document, in the application for accreditation, the independent verifiers that will provide verification services, including lead verifiers, key personnel and any contractors or subcontractors (collectively, accredited independent verification team) and demonstrate that they meet the requirements of section § 62.16470(d)(1). Once accredited, only the accredited independent verification team identified in the accreditation application and accredited by the State may provide a verification report.

(3) An independent verifier must specify the eligible resource categories for which it is seeking accreditation, and an accredited independent verifier may only provide verification services related to an eligible resource category for which it is accredited.

(4) Prospective independent verifiers must meet the requirements of § 62.16475(d) through (f) and demonstrate that they have in place adequate systems and protocols to identify, disclose and avoid potential conflicts of interest.

(5) An accredited independent verifier must not be debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, part 32 of this chapter, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR part 9, subpart 9.4.

(6) An accredited independent verifier must maintain, for its employees, and ensure the maintenance of, for any parties that it employs, professional liability insurance, as defined in 31 CFR 50.5(q), through an insurance provider that possesses a financial strength rating in the top four categories from either

Standard & Poor's or Moody's, specifically, AAA, AA, A or BBB for Standard & Poor's, and Aaa, Aa, A, or Baa for Moody's. Any entity covered by this paragraph must disclose the level of professional liability insurance they possess when entering into contracts to provide verification services pursuant to this regulation.

(d) Requirements for maintenance of accreditation status, as follows:

(1) Accredited independent verifiers must meet the requirements of § 62.16475 when providing verification services for an authorized account representative; and

(2) The instances specified in § 62.16475(d) are cause for revocation of a verifier's accreditation.

§ 62.16475 What are the procedures of accredited independent verifiers must follow to avoid conflict of interest?

(a) Accredited independent verifiers must not provide verification services for any eligible resource for which it has a conflict of interest (COI), which means:

(1) Accredited independent verifiers must have, or have had, no direct or indirect financial interest in, or other financial relationships with, an eligible resource, or any prospective eligible resource, for which they seek to provide a verification report;

(2) Accredited independent verifiers must have, or have had, no direct or indirect organizational or personal relationships with an eligible resource, that would impact their impartiality in assessing the validity and accuracy of the information in an eligibility application or M&V report;

(3) Accredited independent verifiers must have, or have had, no role in the development and implementation of an eligible resource for which an authorized account representative seeks issuance of ERCs, beyond the provision of verification services;

(4) Accredited independent verifiers must not be compensated, financially or otherwise, directly or indirectly, on the basis of the content of its verification report (including eligibility approval of an eligible resource, the quantified and verified MWh in an M&V report, ERC issuance, or the number of ERCs issued);

(5) Accredited independent verifiers must not own, buy, sell, or hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that own, buy, sell, or hold ERCs or other related financial derivatives;

(6) An accredited independent verifier must not be incapable of providing an impartial verification report for any other reason; and

(7) An accredited independent verifier must ensure that the subject of any verification report must not have the opportunity to review or influence any draft or final verification report before its submittal to the Administrator, and the accredited independent verifier must share any drafts of its reports with the Administrator at the same time as it shares them with the subject of the report.

(b) A contract with an eligible resource for the provision of verification services will not constitute a COI.

(c) Verification reports must include an attestation by the accredited independent verifier that it evaluated and disclosed to the Administrator any potential COI related to an eligible resource.

(d) Prior to engaging for the provision of verification services, an accredited independent verifier must demonstrate that it has no COI related to the eligible resource, as specified in paragraph (a) of this section. If a COI is identified for a person or persons within an accredited independent verifier for a specific subject or verification, in accordance with paragraphs (e) and (f) of this section, then an accredited independent verifier may propose to the Administrator steps that will be taken to eliminate the COI which include prohibiting the person or persons with the conflict from any involvement in the matter subject to the conflict, including verification services, access to information related to the verification services, access to any draft or final verification reports, any communications with the person(s) conducting the verification services. In no instance shall an accredited independent verifier engage in verification services for an eligible resource without the approval of the Administrator.

(e) Prior to engaging in verification services and writing a verification report, an accredited independent verifier must disclose to the Administrator all information necessary for the Administrator to evaluate a potential COI (including information concerning its ownership, past and current clients, related entities, as well as any other facts or circumstances that have the potential to create a COI).

(f) Accredited verifiers have an ongoing obligation to disclose to the Administrator any facts or circumstances that may give rise to a COI as defined in paragraph (a) of this section.

(g) The Administrator may reject a verification report from an accredited independent verifier, if the Administrator determines that the accredited independent verifier has a COI as defined in paragraph (a) of this section. If the Administrator rejects an accredited independent verifier report for such reasons, then the eligibility application or M&V report submittal shall be deemed incomplete and ERCs must not be issued pursuant to it.

§ 62.16480 What is the process for the revocation of accreditation status for an independent verifier?

(a) The Administrator may revoke the accreditation of an independent verifier at any time for cause, including for the reasons specified in paragraphs (a)(1) through (4) of this section.

(1) Failure to fully disclose any issues that may lead to a COI with respect to an eligible resource, or other related entity, in accordance with § 62.16475(d) through (f).

(2) The accredited independent verifier is no longer qualified to provide verification services.

(3) Negligence in the conduct of verification activities, or neglect of responsibilities pursuant to the requirements of §§ 62.16465, 62.16470, and 62.16475.

(4) Intentional misrepresentation of data in a verification report.

(b) [Reserved]

Designated Representatives

§ 62.16485 How are designated representatives and alternate designated representatives authorized and what role do authorized designated representatives and alternate designated representatives play?

(a) Except as provided under § 62.16495, each affected EGU, and each eligible resource shall have one and only one designated representative, with regard to all matters under the CO_2 Rate-based Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the affected EGU in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the designated representative by the

Administrator regarding the affected EGU.

(b) Except as provided under § 62.16495, each affected EGU may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected must include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the affected EGU and must act in accordance with the certification statement in § 62.16500(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under § 62.16500,

(i) The alternate designated representative must be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the affected EGU shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding any such affected EGU.

(c) Except in this section, §§ 62.16490 through 62.16510, and § 62.16570, whenever the term ''designated representative'' (as distinguished from the term ''common designated representative'') is used in this subpart, the term shall be construed to include the designated representative.

§ 62.16490 What responsibilities do designated representatives and alternate designated representatives hold?

(a) Except as provided under § 62.16510 concerning delegation of authority to make submissions, each submission under the CO_2 Rate-based Trading Program must be made, signed, and certified by the designated representative or alternate designated representative for each affected EGU for which the submission is made. Each such submission must include the following certification statement by the designated representative or alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the affected EGU for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(b) The Administrator will accept or act on a submission made for an affected EGU only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 62.16510.

§ 62.16495 What are the processes for changing designated representatives, alternate designated representatives, owners and operators, and affected EGUs?

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the affected EGU.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 62.16500. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the affected EGU.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of an affected EGU is not included in the list of owners and operators in the certificate of representation under § 62.16500, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the affected EGU, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of affected EGU, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative must submit a revision to the certificate of representation under § 62.16500 amending the list of owners and operators to reflect the change.

(d) *Changes in affected EGUs at the source.* Within 30 days of any change in which affected EGUs are located at a source (including the addition or removal of an affected EGU), the designated representative or any alternate designated representative must submit a certificate of representation under § 62.16500 amending the list of affected EGUs to reflect the change.

(1) If the change is the addition of an affected EGU that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity from whom the affected EGU was purchased or otherwise obtained (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was purchased or otherwise obtained, and the date on which the affected EGU became located at the source.

(2) If the change is the removal of an affected EGU, then the certificate of representation must identify, in a format prescribed by the Administrator, the entity to which the affected EGU was sold or that otherwise obtained the affected EGU (including name, address, telephone number, and facsimile transmission number (if any)), the date on which the affected EGU was sold or otherwise obtained, and the date on which the affected EGU became no longer located at the source.

§ 62.16500 What must be included in a certificate of representation?

(a) A complete certificate of representation for a designated representative or an alternate designated representative must include the elements in paragraphs (a)(1) through (5) of this section in a format prescribed by the Administrator.

(1) Identification of the affected EGU for which the certificate of representation is submitted, including names, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type,

identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such affected EGU, net-summer capacity, actual or projected date of commencement of commercial operation, and a statement of whether such affected EGU is located in Indian country. If a projected date of commencement of commercial operation is provided, then the actual date of commencement of commercial operation must be provided when such information becomes available.

(2) The name, address, email address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected EGU.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected EGU'';

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of the owners and operators of the affected EGU and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the affected EGU''; and

(iii) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected EGU, or where a utility or industrial customer purchases power from an affected EGU under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the affected EGU; and ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of ERCs by contract, ERCs and proceeds of transactions involving CO_2 Rate-based Trading Program ERCs will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 62.16505 What is the Administrator's role in objections concerning designated representatives and alternate designated representatives?

(a) Once a complete certificate of representation under § 62.16500 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 62.16500 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of ERC transfers.

§ 62.16510 What process must designated representatives and alternate designated representatives follow to delegate their authority?

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, email address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16510(d) shall be deemed to be an electronic submission by me''; and

(ii) ''Until this notice of delegation is superseded by another notice of delegation under § 62.16510(d), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16510 is terminated.''

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

Monitoring, Recordkeeping, Reporting

§ 62.16515 How are compliance accounts and general accounts established and used, and how is ERC issuance documentation accessed?

(a) *Compliance accounts.* (1) Upon receipt of a complete certificate of representation under § 62.16500, the Administrator will establish a compliance account for the affected EGU for which the certificate of representation was submitted, unless the affected EGU already has a compliance account. The designated representative and any alternate designated representative of an affected EGU shall be the authorized account representative and the alternate authorized account representative, respectively, of the compliance account.

(2) A compliance account will hold ERCs intended for surrender by a designated representative when demonstrating an affected EGUs compliance with a CO_2 emission standard as applicable in § 62.16420. A compliance account may be established for a facility with one or more affected EGUs, provided that the account contains subaccounts for each affected EGU within the facility.

(b) *Retirement accounts.* (1) A retirement account, into which ERCs held in a compliance account for an affected EGU are surrendered by the owner or operator of an affected EGU, for use in demonstrating compliance with its emission standards. The retirement account may only be held by the Administrator, and ERCs deposited into it are permanently retired. Once an ERC is retired, the ERC shall no longer be transferable to another account in that ERC tracking system or any other ERC tracking system.

(2) [Reserved]

(c) *General accounts*—(1) *Application for a general account.* (i) Designated representatives of affected EGUs, authorized account representatives of eligible resources, and any other person may apply to open a general account, for the purpose of holding and transferring ERCs, by submitting to the Administrator a complete application for a general account. Such application must designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to ERCs held in the general account.

(B) The agreement by which the alternate authorized account representative is selected must include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account must include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, email address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the ERCs held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: ''I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to ERCs held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CO_2 Rate-based Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account''; and

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (c)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to ERCs held in the general account in all matters pertaining to the CO_2 Rate-based Trading Program, notwithstanding any agreement between the authorized account representative and such person;

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative; and

(C) Each person who has an ownership interest with respect to ERCs held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account must be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to ERCs held in the general account. Each such submission must include the following certification statement by the authorized account representative or any alternate authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the ERCs held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) Except in this section, whenever the term ''authorized account representative'' is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the ERCs in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the ERCs in the general account.

(iii)(A) In the event a person having an ownership interest with respect to ERCs in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to ERCs in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative must submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the ERCs in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (c)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the CO_2 Rate-based Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of ERCs transfers.

(5) Delegation by authorized account representative and alternate authorized account representative.

(i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an ''agent'');

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: ''I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under § 62.16515(c)(5)(iv) shall be deemed to be an electronic submission by me''; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: ''Until this notice of delegation is superseded by another notice of delegation under § 62.16515(c)(5)(iv), I agree to maintain an email account and to notify the Administrator immediately of any change in my email address unless all delegation of authority by me under § 62.16515(c)(5) is terminated.''

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request must include a correctly submitted ERC transfer under § 62.16525 for any ERCs in the account to one or more other ATCS accounts.

(ii) If a general account has no ERC transfers to or from the account for a 12-month period or longer and does not contain any ERCs, then the Administrator may notify the authorized account representative for the account that the account will be closed 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted ERC transfer under § 62.16525 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraphs (a) through (c) of this section.

(e) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of ERCs in the account, only if the submission has been made, signed, and certified in accordance with § 62.16490(a) and § 62.16510 or paragraphs (c)(2)(ii) and (5) of this section.

(f) *ERC identification information.* The Administrator will assign to each ERC issued in the EPA ERC tracking system a unique serial identifier that begins with the two digit postal abbreviation of the State in which it was issued and includes the year it was issued, and the eligible resource category that generated it.

(g) *Records supporting ERC issuance.* The Administrator will maintain in the EPA ERC tracking system records of, for each ERC, all of the following:

(1) Account holder names and information;

(2) Authorized account representative name and information;

(3) Qualifying eligible resource identification number, name, State, and contact information including street address, mailing address, phone number, and email;

(4) Category of qualifying eligible resource, according to the categories specified in § 62.16435(a)(4);

(5) The date the qualifying eligible resource commenced generation or saving of energy;

(6) Individual ERCs, each with a unique serial identifier that meets the requirements of paragraph (f) of this section;

(7) Records of ERC transfers among accounts, including the date of transfer and the accounts involved in the transfer;

(8) The date an ERC was surrendered for a compliance demonstration;

(9) Date an ERC was retired by the regulatory body; and

(10) Each eligibility application, EM&V plan, M&V report, and verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(h) *Access to records supporting ERC issuance.* The Administrator will provide in the EPA ERC tracking system access and functionality to allow each ERC to be traceable by the public to the records listed in paragraph (g) of this section. This information will be accessible via an electronic, internet-based portal in the ERC tracking system searchable by, at a minimum, each eligible resource, affected EGU, eligible resource category, and ERC.

(i) *Reports.* The Administrator will provide in the EPA ERC tracking system electronic, internet-based access to enable the generation of at least the following reports, [for as long as this regulation is effective] [in perpetuity]:

(1) *Account activity reports.* By each account holder, reports based on records of their account activity, including the information listed in paragraph (g) of this section;

(2) *Public reports.* By the public, reports that include: All of the information listed in paragraph (g) of this section; a list of all registered account holders in the ERC tracking system, including compliance accounts and general accounts; a list of all eligible resources (including access to all documentation for such eligible resources); a list of all accredited independent verifiers; and aggregate ERC activity statistics on at least an annual basis, for at least the following: Issuance of ERCs, transfers among accounts, transfers in or out of the ERC tracking system to/from another approved ERC tracking system (if relevant), and ERC retirements. The ERC tracking system shall provide this functionality for as long as this regulation is effective; and

(3) *EPA reports.* For the EPA and state regulators, the information listed in paragraph (g) of this section and any other information regarding ERC issuance, transfer, surrender, and retirement for purpose of compliance with this regulation.

(j) *Interactions with other ERC tracking systems.* If approved in connection with a State plan, then an ERC tracking system may provide for transfers of ERCs to/from another ERC tracking system approved in connection with a State plan by the EPA, or provide for transfers of ERCs to/from an EPA-administered ERC tracking system used to administer a federal plan. To transfer ERCs to or from an EPA-administered ERC tracking system, the state ERC tracking system must be approved under subpart UUUU of part 60 of this chapter for such use by the EPA.

§ 62.16525 How must transfers of ERCs be submitted?

(a) An authorized account representative seeking recordation of an ERC transfer must submit the transfer to the Administrator.

(b) An ERC transfer is correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each ERC that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each ERC identified by serial number in the transfer.

§ 62.16530 When will ERC transfers be recorded?

(a) Except as provided in paragraph (b) of this section, within five business days of receiving an ERC transfer that is correctly submitted under § 62.16525, the Administrator will record an ERC transfer by moving each ERC from the transferor account to the transferee account as specified in the transfer.

(b) An ERC transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a compliance period and that includes any ERCs allocated for any compliance period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under § 62.16535 for the compliance period immediately before such allowance transfer deadline.

(c) Where an ERC transfer is not correctly submitted under § 62.16525, the Administrator will not record such transfer.

(d) Within five business days of recordation of an ERC transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of an ERC transfer that is not correctly submitted under § 62.16525, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.

§ 62.16535 How will deductions for compliance with a CO_2 emission standard occur?

For affected EGUs subject to the emission standards listed in Table 1 of this subpart, the owner or operator of an affected EGU must demonstrate compliance with its CO_2 emission standard in accordance with § 62.16420(c) and incorporate ERCs as listed in paragraphs (a) through (f) of this section.

(a) *Availability for deduction for compliance.* ERCs are available to be deducted from a compliance account and used for compliance with an affected EGU's CO_2 emissions standard for a compliance period only if the ERCs:

(1) Were allocated for a year in such compliance period or a prior compliance period; and

(2) Are held in the affected EGU's compliance account as of the allowance transfer deadline for such compliance period.

(b) *Deductions for compliance.* After the recordation, in accordance with § 62.16530, of ERC transfers submitted by the ERC transfer deadline for a compliance period, the Administrator will deduct from each affected EGU's compliance account ERCs available under paragraph (a) of this section in order to determine whether the affected EGU meets the CO_2 emission standard for such compliance period, as follows:

(1) Until the amount of ERCs deducted and subsequently added to the total MWh generated by the affected EGU adjusts the affected EGU's CO_2 emission rate to equal the CO_2 emission standard for such compliance period; or

(2) If there are insufficient ERCs to complete the deductions in paragraph (b)(1) of this section, until no more ERCs available under paragraph (a) of this section remain in the compliance account.

(c) *Identification of ERCs by serial number.* The authorized account representative for an affected EGU's compliance account may request that specific ERCs, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a compliance period in accordance with paragraph (b) or (e) of this section. In order to be complete, such request must be submitted to the Administrator by the ERC transfer deadline for such compliance period and include, in a format prescribed by the Administrator, the identification of the affected EGU and the appropriate serial numbers.

(d) *First-in, first-out.* The Administrator will deduct ERCs under paragraph (b) or (e) of this section from the affected EGU's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of ERCs in such request, on a first-in, first-out accounting basis.

(e) *Deductions for exceeding the emission standard.* After making the deductions for compliance under paragraph (b) of this section for a compliance period in a year in which the affected EGU has exceeded its CO_2 emission standard, the Administrator will deduct from the affected EGU's compliance account an amount of ERCs, allocated for a compliance period in a prior year or the compliance period in the year of the excess emissions or in the immediately following year, equal to two times the number of ERCs of the affected EGU's excess emissions.

(f) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (e) of this section.

§ 62.16540 What monitoring requirements must I comply with?

(a) You must follow the requirements described in paragraphs (a)(1) through (8) of this section to monitor emissions and net energy output at your affected EGU.

(1) The owner of operator of an affected EGU required to meet an emission standard must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter, unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to part 75 of this chapter.

(2) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:

(i) "Valid data" (as defined in § 62.16570) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; and

(ii) The corresponding hourly net energy output value is also valid data (Note: for hours with no useful output, zero is considered to be a valid value).

(3) The owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vii) of this section, except as provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If CO_2 concentration is measured on a dry basis, then you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(ii) For each ''valid operating hour'', calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Multiply the result by 2000 lb/ton to convert it to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(3)(ii) of this section over the entire compliance period.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices A and B to part 75 of this chapter.

(vii) The owner operator of an affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected EGU; the owner or operator of an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly affected EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) For each measured hourly heat input rate, use Equation G–4 in Appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each valid operating hour (as defined in paragraph (a)(2) of this section, determine the hourly CO_2 mass emission rate (tons/hr) using the procedures specified in paragraph (a)(4)(ii) of this section and multiply it by the affected EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert to tons of CO_2. Then, multiply the result by 2000 lb/ton to convert to lb.

(iv) The hourly CO_2 tons/hr values and affected EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values that were calculated according to procedures specified in paragraph (a)(4)(iii) of this section over the entire compliance period.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) The owner or operator of an affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output. The owner or operator must calculate net energy output according to paragraph (a)(5)(i) of this section.

(i) For each valid operating hour of a compliance period that was used in paragraph (a)(3) or (4) of this section to calculate the total CO_2 mass emissions, you must determine P_{net} (the corresponding hourly net energy output in MWh) according to the procedures in paragraphs (a)(5)(i)(A) and (B) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, then you must still determine the net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(3) or (4) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(A) Calculate P_{net} for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_A}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{net} = Net energy output of your affected EGU for each valid operating hour (as defined in paragraph (a)(2) of this section) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(i)(B) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions as defined in § 62.16570, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable as defined in § 62.16570) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total net energy output consists of electric or direct mechanical output and 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(B) If applicable to your affected EGU (for example, for combined heat and power), then you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

$(Pt)_{ps}$ = Useful thermal output of steam (measured relative to SATP conditions as defined in § 62.16570, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU.

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions as defined in § 62.16570 or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(C) Sum all of the values of P_{net} over the entire compliance period. Then, divide the total CO_2 mass emissions from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the P_{net} values to determine the CO_2 emission rate (lb/net MWh) for the compliance period.

(ii) [Reserved]

(6) In accordance with § 60.13(g) of this chapter, if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emission standard, then the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, then the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected EGUs and the operating time must be expressed as "stack operating hours" (as defined in § 72.2 of this chapter).

(7) In accordance with § 60.13(g) of this chapter, if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3)(i) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), then the hourly CO_2 mass emissions and the "stack operating time" (as defined in § 72.2 of this chapter) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emission standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(8) If two or more affected EGUs serve a common electric generator, then you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the affected EGUs are identical, then you may apportion the combined hourly net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(b) [Reserved]

§ 62.16545 May I bank CO_2 ERCs for future use or transfer?

(a) An ERC may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any ERC that is held in a compliance account or a general account will remain in such account unless and until the ERC is deducted or transferred under §§ 62.16530, 62.16535, 62.16550, or 62.16565.

§ 62.16550 How does the Administrator process account errors?

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any ATCS account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 62.16555 What are my reporting, notification and submission requirements?

You must prepare and submit reports according to paragraphs (a) through (g) of this section, as applicable.

(a)(1) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter and you must include the following information, as applicable in the quarterly reports:

(i) The percentage of valid operating hours in each quarter described § 62.16540(a)(2) (*i.e.,* the total number of valid operating hours) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(ii) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour in the compliance period;

(iii) The net electric output and the net energy output (P_{net}) values for each valid operating hour in the compliance period;

(iv) The calculated CO_2 mass emissions (lb) for each valid operating hour in the compliance period;

(v) The sum of the hourly net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours in the compliance period;

(vi) ERC replacement generation (if any), properly justified (see paragraph (a)(1)(viii) of this section);

(vii) The calculated CO_2 mass emission rate for the compliance period (lb/net MWh); and

(viii) If the report covers the final quarter of a compliance period, then you must include the CO_2 emission standard (as identified in Table 1 of this subpart) with which your affected EGU must comply, your CO_2 emission rate calculated according to § 62.16420(c), and if an affected EGU is complying with an emission standard by using ERCs, then the designated representative must also include in the report a list of all unique ERC serial numbers retired in the compliance period, and, for each ERC, the date an ERC was surrendered and retired and eligible resource identification information sufficient to demonstrates that it meets the requirements of § 62.16435 and qualifies to be issued ERCs (including location, type of qualifying generation or savings, date commenced generating or saving, and date of generation or savings for which the ERC was issued).

(b) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (a) of this section, then the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 62.16540(a)), and shall not be used in the compliance determinations.

(c) The designated representative of each affected EGU at the facility must make all submissions required under the CO_2 Rate-based Trading Program, except as provided in § 62.16510. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(d) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(e) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, then you must report in accordance with the requirements of part 98, subpart PP, of this chapter and either:

(1) Report in accordance with the requirements of part 98, subpart RR, of this chapter, if injection occurs on-site; or

(2) Transfer the captured CO_2 to an affected EGU or facility that reports in accordance with the requirements of part 98, subpart RR, of this chapter, if injection occurs off-site.

(g) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected EGUs.

§ 62.16560 What are my recordkeeping requirements?

(a) The owner or operator of each affected EGU must maintain the records, as described in paragraph (a)(1) of this section, for at least 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record.

(1) Unless otherwise provided, the owner or operator of an affected EGU must maintain the following records on site for at least 2 years after the date of each compliance period, compliance true-up period, occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7 of this chapter. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s). This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 62.16500 for the designated representative for each affected EGU and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents must be retained on site at the affected EGU beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 62.16500 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, documents, data files, calculations and methods, other submissions and all records made or required under, or to demonstrate compliance with an affected EGU's emission standard under § 62.16420 and any other requirements of the CO_2 Rate-based Trading Program.

(iv) Data that are required to be recorded by part 75, subpart F, of this chapter.

(v) Data with respect to any ERCs generated by the affected EGU or used by the affected EGU in its compliance demonstration including the information in paragraphs (a)(1)(v)(A) and (B) of this section.

(A) All documents related to any ERCs used in a compliance demonstration, including each eligibility application, EM&V plan, M&V report, and independent verifier verification report associated with the issuance of each specific ERC, and each regulatory approval and any documentation that supports the issuance of each ERC by the Administrator.

(B) All records and reports relating to the surrender and retirement of ERCs for compliance with this regulation, including the date each individual ERC with a unique serial identification number was surrendered and/or retired.

(2) [Reserved]

(b) [Reserved]

§ 62.16565 What actions may the Administrator take on submissions?

(a) The Administrator may review and conduct independent audits concerning any submission under the CO_2 Rate-based Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct ERCs from or transfer ERCs to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

Definitions

§ 62.16570 What definitions apply to this subpart?

The terms used in this subpart have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her delegate, or the authorized state official under an approved state plan that incorporates this subpart.

Affected electric generating unit or *Affected EGU* means any steam generating unit, IGCC, or stationary combustion turbine that meets the applicability requirements in §§ 60.5840(b) and 60.5845 of this chapter. An affected EGU is not an eligible resource.

Allowable CO_2 emission rate means, for an affected EGU, the most stringent State or federal CO_2 emission rate limit (in lb/MWh or, if in lb/mmBtu, converted to lb/MWh by multiplying it by the affected EGU's heat rate in mmBtu/MWh) that is applicable to the affected EGU and covers the longest averaging period not exceeding 1 year.

Allowance system means a control program under which the owner or operator of each affected EGU is required to hold an authorization for each specified unit of carbon dioxide emitted from that facility during a specified period and which limits the total amount of such authorizations available to be held for carbon dioxide for a specified period and allows the transfer of such authorizations not used to meet the authorization-holding requirement.

Allowance Tracking and Compliance System (ATCS) means the system by which the Administrator records allocations, deductions, and transfers of ERCs under the CO_2 Rate-based Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole ERCs.

Alternate designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the facility, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the CO_2 Rate-based Trading Program. If the affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Also see capacity factor.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of ERCs held in the general account and, for a CO_2 Rate-based Trading Program affected EGU's, the designated representative of the affected EGU is the authorized account representative.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Baseline means the electricity use that would have occurred without implementation of a specific EE measure.

Biomass means biologically based material that is living or dead (*e.g.,* trees, crops, grasses, tree litter, roots) above and belowground, and available on a renewable or recurring basis. Materials that are biologically based include non-fossilized, biodegradable organic material originating from modern or contemporarily grown plants, animals, or microorganisms (including plants, products, byproducts and residues from agriculture, forestry, and related activities and industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Business day means a day that does not fall on a weekend or a federal holiday.

Capacity factor means, as used for the output based set-aside, the ratio of the net electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous net summer capacity during the same period.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

CO_2 emissions limitation means the tonnage of CO_2 emissions authorized in a compliance period in a given year by the CO_2 allowances available for deduction for the affected EGU under § 62.16535(a) for such compliance period.

CO_2 Rate-Based Trading Program means a multi-state CO_2 air pollution control and emission reduction program established in accordance with this subpart and subpart UUUU of part 60 of this chapter (including such a program that is revised in a State plan or state allowance distribution methodology, or by the Administrator under subpart UUUU of part 60 of this chapter), as a means of controlling CO_2 emissions.

Coal means the definition as defined in subpart TTTT of part 60 of this chapter.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as *''cogeneration''*) means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy affected EGU.

Common practice baseline or CPB means a baseline derived based on a default technology or condition that would have been in place at the time of implementation of an EE measure in the absence of the EE measure (for example, the standard or market-average or pre-existing equipment that a typical consumer/building owner would have continued to use or would have installed at the time of project implementation in a given circumstance, such as a given building type, EE program type or delivery mechanism, and geographic region).

Common stack means a single flue through which emissions from two or more units are exhausted.

Compliance account means an Allowance Transfer and Compliance System account, established by the Administrator for an affected EGU under this subpart, in which any ERC allocations to the affected EGUs at the affected EGU are recorded and in which are held any CO_2 allowances available for use for a compliance period in a given year in complying with the affected EGU's CO_2 emission standard in accordance with §§ 62.16420 and 62.16535.

Compliance period means the multi-year periods starting January 1 of the first calendar year of the period, except as provided in § 62.16420(c)(3), and ending on December 31 of the last calendar year, inclusive:

(1) Compliance Period 1 means the period of 3 calendar years from January 1, 2022 to December 31, 2024;

(2) Compliance Period 2 means the period of 3 calendar years from January 1, 2025 to December 31, 2027; and

(3) Compliance Period 3 means the period of 2 calendar years from January 1, 2028 to December 31, 2029.

Conservation voltage regulation (or reduction) (CVR) means an EE measure that produces electricity savings by reducing (or regulating) voltage at the electrical feeder level.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of CO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and § 62.16540(a)(3). The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow;

(2) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(3) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(4) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control area operator means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.

Deemed savings means estimates of average annual electricity savings for a single unit of an installed demand-side EE measure that: has been developed from data sources (such as prior metering studies) and analytical methods widely considered acceptable for the measure; and is applicable to the situation and conditions in which the measure is implemented. Individual parameters or calculation methods also can be deemed, including EUL values. Common sources of deemed savings values are previous evaluations and studies that involved actual measurements and analyses. Deemed savings values are applicable for specific demand-side EE measures. A single deemed savings value may not be used for a program as a whole, nor for a multi-measure project, because of the degree of variation in how systems are used in different building types or market segments.

Demand-side energy efficiency or demand-side EE means an installed piece of equipment or system, a modification of existing equipment or system, or a strategy intended to affect consumer electricity-use behavior, that results in a reduction in electricity use (in MWh) at an end-use facility, premises, or equipment connected to the electricity grid. Demand-side EE is implemented through energy efficiency activities, projects, programs or measures

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Designated representative means, for a CO_2 Rate-based Trading affected EGU and each affected EGU at the affected EGU, the natural person who is authorized by the owners and operators of the affected EGU and all such affected EGUs at the affected EGU, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the CO_2 Rate-based Trading Program. If the CO_2 Rate-based Trading affected EGU is also subject to the Acid Rain Program, TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, TR SO_2 Group 1 Trading Program, or TR SO_2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus thermal output) on a higher heating value basis of the EGU at the base load rating and ISO conditions.

Distillate oil means the definition as defined in subpart TTTT of part 60 of this chapter.

Effective useful life (EUL) means the duration over which electricity savings from an EE measure occur, reported in years. EUL values are typically specific to individual EE projects but also may be specified by an EE program.

Electricity savings means the savings that results from a change in electricity use resulting from the implementation of demand-side EE.

Eligible resource means a resource that meets the requirements of § 62.16435 and has been registered with the EPA-administered ERC tracking system or an ERC tracking system approved in a State plan by the EPA. An eligible resource is not an affected EGU.

EM&V plan means an evaluation measurement and verification plan that meets the requirements of § 62.16455.

Emissions means air pollutants exhausted from an affected EGU into the atmosphere; emissions must be measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the affected EGU or facility is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Emission rate credit (ERC) means a tradable compliance instrument that meets the requirements of § 60.5790(c) of this chapter.

ERC deduction or *deduct ERCs* means the permanent withdrawal of ERCs by the Administrator from a compliance account (*e.g.,* in order to account for compliance with the applicable CO_2 emission standard).

Energy efficiency program or EE program means organized activities sponsored and funded by a particular entity to promote the adoption of one or more EE project or EE measure for the purpose of reducing electricity use.

Energy efficiency project or EE project means a combination of multiple technologies, energy-use practices or behaviors implemented at a single facility or premises for the purpose of reducing electricity use; EE projects may be implemented as part of an EE program or as an independent privately-funded action.

Energy efficiency measure or EE measure means a single technology, energy-use practice or behavior that, once implemented or adopted, reduces electricity use of a particular end-use, facility, or premises; EE measures may be implemented as part of an EE program or as an independent privately-funded action.

ERC held or *hold ERCs* means the ERCs treated as included in an ATCS account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, ERC transfer in accordance with this subpart.

ERC transfer deadline means, for a compliance period in a given year, midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such compliance period and is the deadline by which an ERC transfer must be submitted for recordation in a affected EGU's compliance account in order to be available for use in complying with the affected EGU's CO_2 emission standard for such compliance period in accordance with §§ 62.16420 and 62.16535.

Essential generating characteristics means any characteristic that affects the eligibility of the qualifying energy generating resource for generating ERCs pursuant to this regulation, including the type of resource.

Excess emissions means any ton of emissions from the affected EGUs at an affected EGU during a compliance period that exceeds the CO_2 emissions limitation for the affected EGU for such compliance period.

Existing state program, requirement, or measure means, in the context of a State plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Facility means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of ''major source'', ''stationary source'', or ''source'' as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

Final compliance period means a compliance period within the final period, each being 2 calendar years (with a calendar year beginning on January 1 and ending on December 31), and the first final compliance period beginning on January 1, 2030 and ending December 31, 2031.

Final period means the period that begins on January 1, 2030 and continues thereafter. The final period is comprised of final compliance periods, each of which is 2 calendar years (with a calendar year beginning on January 1 and ending on December 31).

Fossil fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Fossil-fuel-fired means, with regard to an affected EGU, combusting any amount of fossil fuel.

Gaseous fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

General account means an ATCS account established under this subpart that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, for an affected EGU, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the affected EGU and any on-site emission controls).

GS–ERC means an ERC issued for net energy output MWh of gas shift to, but which may not be used for compliance by, an affected EGU that is a stationary combustion turbine. Aside from this restriction on use for compliance, GS–ERCs are subject to all other provisions of this subpart related to ERCs.

Heat input means, for an affected EGU for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the affected EGU multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for an affected EGU, the amount of heat input (in mmBtu) divided by affected EGU operating time (in hr) or, for an affected EGU and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the affected EGU operating time (in hr) during which the affected EGU combusts the fuel.

Heat rate means, for an affected EGU, the affected EGU's maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the affected EGU's maximum hourly load.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Indian country means ''Indian country'' as defined in 18 U.S.C. 1151.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

Interim period means the period of 8 calendar years from January 1, 2022 to December 31, 2029. The interim period is comprised of three compliance periods, compliance period 1, compliance period 2, and compliance period 3.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

M&V report means a monitoring and verification report that meets the requirements of § 62.16460.

Maximum design heat input means, for an affected EGU, the maximum amount of fuel per hour (in Btu/hr) that the affected EGU is capable of combusting on a steady state basis as of the initial installation of the affected EGU as specified by the manufacturer of the affected EGU.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) of such completion as specified by the person conducting the physical change.

Natural gas means the definition as defined in subpart TTTT of part 60 of this chapter.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the affected EGU (*e.g.,* steam delivered to an industrial process for a heating application); and

(2) For combined heat and power facilities where at least 20.0 percent of the total net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output (*e.g.,* steam delivered to an industrial process for a heating application).

Net summer capacity means the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30.) This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.

Operate or *operation* means, with regard to an affected EGU, to combust fuel.

Operator means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at an affected EGU respectively, any person who operates, controls, or supervises an affected EGU at the affected EGU or the affected EGU and includes, but is not limited to, any holding company, utility system, or plant manager of such affected EGU or affected EGU.

Owner means, for a CO_2 Rate-based Trading affected EGU or an affected EGU at an affected EGU respectively, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected EGU at the affected EGU or the affected EGU;

(2) Any holder of a leasehold interest in an affected EGU at the affected EGU or the affected EGU, provided that, unless expressly provided for in a leasehold agreement, ''owner'' shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such affected EGU; and

(3) Any purchaser of power from a affected EGU at the affected EGU or the affected EGU under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to an affected EGU, that an affected EGU is unavailable for service and the affected EGU's owners and operators: have taken on as enforceable obligations in the operating permit that covers the affected EGU the conditions of § 62.16415; or rescinded or otherwise terminated all permits required for construction or operation of the affected EGU under the Clean Air Act. Cessations in operations that do not meet this definition do not constitute permanent retirements.

Petroleum means the definition as defined in subpart TTTT of part 60 of this chapter.

Qualified biomass means a biomass feedstock that is demonstrated to qualify as a method to control increases of CO_2 levels in the atmosphere.

Random error means errors occurring by chance that may cause electricity savings values to be inconsistently overestimated or underestimated, and may result from a change in electricity use due to unaccounted-for factors that affect electricity use. The magnitude of random error can be quantified based on the variations observed across different units.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to ERCs, the moving of ERCs by the Administrator into, out of, or between ATCS accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to an affected EGU, the demolishing of an affected EGU, or the permanent retirement and permanent disabling of an affected EGU, and the construction of another affected EGU (the replacement affected EGU) to be used instead of the demolished or retired affected EGU (the replaced affected EGU).

Solid fuel means the definition as defined in subpart TTTT of part 60 of this chapter.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a ''solid waste incineration unit'' as defined in section 129(g)(1) of the Clean Air Act.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

State measures means measures that the State adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable State plan.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly then it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any ''submission'' or ''service'' deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Systematic error means inaccuracies in the same direction, causing electricity savings values to be consistently either overestimated or underestimated, and may result from factors such as incorrect assumptions, a methodological issue, or a flawed reporting system.

Transmission and distribution loss means the difference between the quantity of electricity that serves a load (measured at the busbar of the generator) and the actual electricity use at the final distribution location (measured at the on-site meter).

Transmission and distribution measures or T&D measures means EE measures intended to improve the efficiency of the electrical transmission and distribution system by decreasing electricity loses on the system.

Unit operating day means, with regard to an affected EGU, a calendar day in which the affected EGU combusts any fuel.

Unit operating hour or *hour of unit operation* means, with regard to an affected EGU, an hour in which the affected EGU combusts any fuel.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 of this chapter apply (except for qualifying commercial billing meters).

Verification report means a report that meets the requirements of § 62.16465.

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

§ 62.16575 What measurements, abbreviations, and acronyms apply to this subpart?

The measurements, abbreviations, and acronyms used in this subpart are defined as follows:

ADR—alternated designated representative
Btu—British thermal unit
CPP—clean power plan
CO_2—carbon dioxide
COI—conflict of interest
CVR—conservative voltage regulation
DR—designated representative
EE—energy efficiency
EGU—electric generating unit
EM&V—evaluation, measurement, and verification
ERC—emission rate credit
GCV—gross calorific value
GJ—giga joule
H_2O—water
hr—hour
IGCC—integrated gasification combined cycle
kg—kilogram
kW—kilowatt electrical
kWh—kilowatt hour
lb—pound
M&V—measurement and verification
mmBtu—million Btu
MWe—megawatt electrical
MWh—megawatt hour
T&D—transmission and distribution
O_2—oxygen
PSD—prevention of significant deterioration
yr—year

TABLE 1 TO SUBPART NNN OF PART 62—CO_2 EMISSION STANDARDS (POUNDS OF CO_2 PER NET MWH)

Compliance period	Affected steam generating unit or integrated gasification combined cycle (IGCC) emission standards	Affected stationary combustion turbine emission standard
Compliance Period 1 (2022–2024)	1,671	877
Compliance Period 2 (2025–2027)	1,500	817
Compliance Period 3 (2028–2029)	1,380	784
Final Compliance Periods	1,305	771

TABLE 2 TO SUBPART NNN OF PART 62—INCREMENTAL GENERATION FACTOR FOR EMISSION RATE CREDITS (DIMENSIONLESS)

Compliance period	Incremental Generation Factor
Compliance Period 1 (2022–2024)	.22
Compliance Period 2 (2025–2027)	.32
Compliance Period 3 (2028–2029)	.28
Final Compliance Periods	.26

PART 78—APPEAL PROCEDURES

■ 6. The authority citation for Part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7411, 7426, 7601, and 7651 *et seq.*

■ 7. Section 78.1 is amended by revising paragraph (a)(1) and adding paragraphs (b)(18) and (19) to read as follows:

§ 78.1 Purpose and scope.

(a)(1) This part shall govern appeals of any final decision of the Administrator under subparts MMM and NNN of part 62 of this chapter, part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter or State regulations approved under § 51.123(o)(1) or (2) of this chapter, subparts AAA through III of part 96 of this chapter or State regulations approved under § 51.124(o)(1) or (2) of this chapter, subparts AAAA through IIII of part 96 of this chapter or State regulations approved under § 51.123(aa)(1) or (2) of this chapter, part 97 of this chapter, or subpart RR of part 98 of this chapter; provided that matters listed in § 78.3(d) and preliminary, procedural, or intermediate decisions, such as draft Acid Rain permits, may not be appealed. All references in paragraph (b) of this section and in § 78.3 to subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through IIII of part 96 of this chapter shall be read to include the comparable provisions in State regulations approved under § 51.123(o)(1) or (2) of this chapter, § 51.124(o)(1) or (2) of this chapter, and § 51.123(aa)(1) or (2) of this chapter, respectively.

* * * * *

(b) * * *

(18) Under subpart MMM of part 62 of this chapter,

(i) The decision on allocation of CO_2 allowances under § 62.16240 of this chapter.

(ii) The decision on allocation of CO_2 allowances from set-asides under § 62.16245 of this chapter.

(iii) The decision on the transfer of CO_2 allowances under § 62.16330 of this chapter.

(iv) The decision on the deduction of CO_2 allowances under § 62.16340 of this chapter.

(v) The correction of an error in an ATCS account under § 62.16355 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CO_2 allowances based on the information as adjusted under § 62.16370 of this chapter.

(vii) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

(19) Under subpart NNN of part 62 of this chapter,

(i) The decision on emission rate credit issuance, adjustment, and revocation under § 62.16435.

(ii) The decision on qualification status of eligible resources to receive emission rate credits under § 62.16460.

(iii) The decision on revocation of qualification status of an eligible resource under § 62.16440.

(iv) The decision on Adjustments for error or misstatement, suspension of ERC issuance under § 62.16450.

(v) The decision on accreditation of independent verifiers under § 62.16470.

(vi) The decision on revocation of accreditation status under § 62.16480.

(vii) The decision on the transfer of emission rate credits under § 62.16530 of this chapter.

(viii) The decision on the deduction of emission rate credits under § 62.16535 of this chapter.

(ix) The correction of an error in an ATCS account under § 62.16550 of this chapter.

(x) The adjustment of information in a submission and the decision on the deduction and transfer of emission rate credits based on the information as adjusted under § 62.16565 of this chapter.

(xi) The finalization of compliance period emissions data, including retroactive adjustment based on audit.

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