Title 40 - Protection of Environment

CHAPTER I - ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

## Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

### Introduction

### § 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. State plans under the emission guidelines in this subpart are also subject to the requirements of subpart Ba. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

### § 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide ($CO_2$) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii) , with respect to GHG emissions from facilities regulated in the State plan, 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) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of § 52.21(b)(50)(ii) of this chapter, with respect to GHG emissions from facilities regulated in the State plan, 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 facilities regulated in the State plan, 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 GHG emissions from facilities regulated in the State plan, 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.

**§ 60.5710b Am I affected by this subpart?**

(a) If you are the Governor of a State in the contiguous United States with one or more affected EGUs that must be addressed in your State plan as indicated in § 60.5845b, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs, or if all EGUs in your State are excluded from being affected EGUs per § 60.5850b, you must submit a negative declaration letter in place of the State plan.

(b) If you are a coal-fired steam generating unit that has demonstrated that it plans to permanently cease operation prior to January 1, 2032, consistent with § 60.5740b(a)(9)(ii), and that would be an affected EGU under these emissions guidelines but for § 60.5850b(k), you must comply with § 60.5876b.

**§ 60.5715b What is the review and approval process for my State plan?**

(a) The EPA will determine the completeness of your State plan submission according to §60.27a(g). The timeline for completeness determinations is provided in § 60.27a(g)(1).

(b) The EPA will act on your State plan submission according to §60.27a. The Administrator will have 12 months after the date the final State plan or State plan revision (as allowed under § 60.5790b) is found to be complete to fully approve, partially approve, conditionally approve, partially disapprove, and/or fully disapprove such State plan or revision or each portion thereof.

**§ 60.5720b What if I do not submit a State plan or my State plan is not approvable?**

(a) If you do not submit an approvable State plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan replacing the relevant portion(s) of the Federal plan.

**§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?**

A State may meet its CAA section 111(d) obligations only by submitting a State plan or a negative declaration letter (if applicable).

**§ 60.5730b Is there an approval process for a negative declaration letter?**

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, consistent with the electronic submission requirements in § 60.5875b, the EPA will place a copy in the public docket and publish a notice in the *Federal Register*. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014, reconstruction on or before June 18, 2014, or modification on or before May 23, 2023, is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

**State Plan Requirements**

**§ 60.5740b What must I include in my federally enforceable State plan?**

(a) You must include the components described in paragraphs (a)(1) through (13) of this section in your State plan submittal. The final State plan must meet the requirements and include the information required under § 60.5775b and must also meet any administrative and technical completeness criteria listed in § 60.27a(g)(2) through (3) of this part that are not otherwise specifically enumerated here.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by your State plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. You must also identify the subcategory into which you have classified each affected EGU. States must subcategorize affected EGUs into one of the following subcategories:
(i) *Long-term coal-fired steam generating units,* consisting of coal-fired steam generating units that are not medium-term coal-fired steam generating units and do not plan to permanently cease operation before January 1, 2039.
(ii) *Medium-term coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.
(iii) *Base load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.
(iv) *Intermediate load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(v) *Low load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.
(vi) *Base load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.
(vii) *Intermediate load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.
(viii) *Low load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(2) *Inventory of Data from Affected EGUs.* You must include an inventory of the following data from the affected EGUs:
(i) The nameplate capacity of the affected EGU, as defined in § 60.5880b.
(ii) The base load rating of the affected EGU, as defined in § 60.5880b.
(iii) The data within the continuous 5-year period immediately prior to **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]** including:
(A) The sum of the $CO_2$ emissions during each quarter in the 5-year period.
(B) For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategories, the sum of the gross energy output during each quarter in the 5-year period; for affected EGUs in the low load natural gas- and oil-fired subcategories, the sum of the heat input during each quarter in the 5-year period.
(C)The heat input for each fuel type combusted during each quarter in the 5-year period.
(D) The start date and end date of the most representative continuous 8-quarter period used to determine the baseline of emission performance under § 60.5775b(d), the sum of the $CO_2$ mass emissions during that period, the sum of the gross energy output or, for affected EGUs in the low load natural gas-fired subcategory or low load oil-fired subcategory, the sum of the heat input during that period, and sum of the heat input for each fuel type combusted during that period.

(3) *Standards of Performance.* You must include all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance that does not exceed the level calculated through the use of the methods described in § 60.5775b(b), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(4) *Requirements related to Subcategory Applicability*.
(i) You must include the following enforceable requirements to establish an affected EGU's applicability for each of the following subcategories:

(A) For medium-term coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(B) For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, you must include a requirement to remove the capability to fire coal before January 1, 2030.

(C) For each affected EGU, you must also estimate coal, oil, and natural gas usage by heat input for the first 3 calendar years after January 1, 2030.

(D) For affected EGUs that plan to permanently cease operation, you must include a requirement that each such affected EGU comply with applicable State and Federal requirements for permanently ceasing operation, including removal from its respective State's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU.

(5) *Increments of Progress.* You must include in your State plan legally enforceable increments of progress as required elements for affected EGUs in the long-term coal-fired steam generating unit and medium-term coal-fired steam generating unit subcategories.
(i) For affected EGUs in the long-term coal-fired steam generating unit subcategory using carbon capture to meet their applicable standard of performance and affected EGUs in the medium-term coal-fired steam generating unit subcategory using natural gas co-firing to meet their applicable standard of performance, State plans must assign calendar-date deadlines to each of the increments of progress described in subsection (a)(5)(i) and meet the website reporting obligations of subsection (a)(5)(iii):
(A) Submittal of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration for each affected EGU in the State plan.
*(1)* For each affected unit in the long-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or front-end engineering and design (FEED) study.
*(2)* For each affected unit in the medium-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.

(B) Completion of awarding of contracts. The owner or operator of an affected EGU can demonstrate compliance with this increment of progress by submitting sufficient evidence that the appropriate contracts have been awarded.
*(1)* For each affected unit in the long-term coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.
*(2)* For each affected unit in the medium-term coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.

(C) Initiation of on-site construction or installation of emission control equipment or process change.
*(1)* For each affected unit in the long-term coal-fired steam generating unit subcategory, initiation of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

*(2)* For each affected unit in the medium-term coal-fired steam generating unit subcategory, initiation of on-site construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(D) Completion of on-site construction or installation of emission control equipment or process change.
*(1)* For each affected unit in the long-term coal-fired steam generating unit subcategory, completion of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.
*(2)* For each affected unit in the medium-term coal-fired steam generating unit subcategory, completion of on-site construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(E) Commencement of permitting actions related to pipeline construction. The owner or operator of an affected EGU must demonstrate that they have commenced permitting actions by a date specified in the State plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate each affected unit at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.
*(1)* For affected units in the long-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.
*(2)* For affected units in the medium-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts natural gas co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.

(F) For each affected unit in the long-term coal-fired steam generating unit subcategory, a report identifying the geographic location where $CO_2$ will be injected underground, how the $CO_2$ will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(G) Compliance with the standard of performance as follows:
*(1)* For each affected unit in the medium-term coal-fired subcategory, by January 1, 2030.
*(2)* For each affected unit in the long-term coal-fired steam generating subcategory, by January 1, 2032.

(ii) For any affected unit in the long-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than CCS or in the medium-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than natural gas co-firing:
(A) the State plan must include appropriate increments of progress consistent with 40 CFR 60.21a(h) specific to the affected unit's control strategy.
*(1)* The increment of progress corresponding to 40 CFR 60.21a(h)(1) must be assigned the earliest calendar date among the increments.
*(2)* The increment of progress corresponding to 40 CFR 60.21a(h)(5) must be assigned calendar dates as follows: for affected EGUs in the long-term coal-fired steam generating subcategory, no later than January 1, 2032; and for affected EGUs in the medium-term coal-fired steam generating subcategory, no later than January 1, 2030.

(iii) The owner or operator of the affected EGU must post within 30 business days of the State plan submittal a description of the activities or actions that constitute the increments of progress and the schedule for achieving the increments of progress on the Carbon Pollution Standards for EGUs

Website required by § 60.5740b(a)(10). As the calendar dates for each increment of progress occurs, the owner or operator of the affected EGU must post within 30 business days any documentation necessary to demonstrate that each increment of progress has been met on the Carbon Pollution Standards for EGUs Website required by § 60.5740b(a)(10).

(iv) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan increment of progress within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable increment of progress on the Carbon Pollution Standards for EGUs Website required by § 60.5740b(a)(10) within 30 business days.

(6) *Reporting Obligations and Milestones for Affected EGUs that Have Demonstrated They Plan to Permanently Cease Operations.* You must include in your State plan legally enforceable reporting obligations and milestones for affected EGUs in the medium-term coal-fired steam generating unit (§ 60.5740b(a)(1)(ii)) subcategory, and for affected EGUs that invoke RULOF based on a unit's remaining useful life according to paragraphs (a)(6)(i) through (v) of this section:

(i) Five years before the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life) or 60 days after State plan submission, whichever is later, the owner or operator of the affected EGU must submit an Initial Milestone Report to the applicable air pollution control agency that includes the information in paragraphs (a)(6)(i)(A) through (D) of this section:

(A) A summary of the process steps required for the affected EGU to permanently cease operations by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit.

(B) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority or authorities of an EGU's deactivation date and submittal of an official retirement filing with the EGU's relevant reliability authority or authorities .

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar EGUs within the State that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, which include those listed in paragraphs (a)(6)(i)(D)(*1*) through (*3*) of this section:

*(1)* Any correspondence and official filings with the relevant Regional Transmission Organization (RTO), Independent System Operator, Balancing Authority, Public Utilities Commission (PUC), or other applicable authority;

*(2)* Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

*(3)* Any filings with the United States Securities and Exchange Commission or notices to investors, including but not limited to, those listed in paragraphs (a)(6)(i)(D)(*3*)(*i*) through (*v*) of this section.

*(i)* References in forms 10-K and 10-Q, in which the plans for the EGU are mentioned;

*(ii)* Any integrated resource plans and PUC orders approving the EGU's deactivation;

*(iii)* Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

*(iv)* Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

*(v)* Any notification to or from an RTO, Independent System Operator, or Balancing Authority altering the timing of deactivation for the EGU.

(ii) For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the State plan, the owner or operator of the affected EGU must submit an annual Milestone Status Report that includes the information in paragraphs (a)(6)(ii)(A) and (B) of this section:

(A) Progress toward meeting all milestones identified in the Initial Milestone Report, described in § 60.5740b(a)(6)(i); and

(B) Supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months from the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life), the owner or operator of the affected EGU must submit a Final Milestone Status Report. This report must document any actions that the EGU has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) The owner or operator of the affected EGU must post their Initial Milestone Report, as described in paragraph (a)(6)(i) of this section; annual Milestone Status Reports, as described in paragraph (a)(6)(ii) of this section; and Final Milestone Status Report, as described in paragraph (a)(6)(iii) of this section; including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs Website required by paragraph (a)(10) of this section within 30 business days of being filed.

(v) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan reporting milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable reporting milestone on the Carbon Pollution Standards for EGUs Website required by § 60.5740b(a)(10) within 30 business days.

(7) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your State plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(8) *State reporting.* You must include in your State plan a description of the process, contents, and schedule for State reporting to the EPA about State plan implementation and progress.

(9) *Specific requirements for existing coal-fired steam generating EGUs.* Your State plan must include the requirements in paragraphs (a)(9)(i) through (iii) of this section specifically for existing coal-fired steam generating EGUs:

(i) Your State plan must require that any existing coal-fired steam-generating EGU shall operate only subject to a standard of performance pursuant to § 60.5775b or under an exemption of applicability provided under § 60.5850b (including any extension of the date by which an EGU has committed to cease operating pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section).

(ii) You must include a list of the coal-fired steam generating EGUs that are existing sources at the time of State plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to cease operating.

(iii) The State plan must provide that an existing coal-fired steam generating EGU operating past the date listed in the State plan pursuant to paragraph (a)(9)(ii) of this section is in violation of that State plan, except to the extent the existing coal-fired steam generating EGU has received an extension of its date for ceasing operation pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section.

(10) *Carbon Pollution Standards for EGUs Websites*. You must require in your State plan that owners or operators of affected EGUs establish a publicly accessible "Carbon Pollution Standards for EGUs Website" and that they post relevant documents to this website. You must require in your State plan that owners or operators of affected EGUs post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Data should be available in a readily downloadable format. In addition, you must establish a website that displays the links to these websites for all affected EGUs in your State plan.

(11) *Compliance Date Extension.* You may include in your State plan provisions allowing for a compliance date extension for owners or operators of affected EGU(s) that are installing add-on controls and that are unable to meet the applicable standard of performance by the compliance date specified in § 60.5740b(a)(4)(i) due to circumstances beyond the owner or operator's control. Such provisions may allow an owner or operator of an affected EGU to request an extension of no longer than one year from the specified compliance date and may only allow the owner or operator to receive an extension once. The optional State plan mechanism must provide that an extension request contains a demonstration of necessity that includes the following:

(i) A demonstration that the owner or operator of the affected EGU cannot meet its compliance date due to circumstances beyond the owner or operator's control and that the owner or operator has met all relevant increments of progress and otherwise taken all steps reasonably possible to install the controls necessary for compliance by the specified compliance date up to the point of the delay. The demonstration shall:

(A) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(B) Identify and describe the controls to be installed at each affected unit to comply with the applicable standard of performance pursuant to § 60.5775b;

(C) Describe and demonstrate all progress towards installing the controls and that the owner or operator has itself acted consistent with achieving timely compliance, including:

*(1)* Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

*(2)* Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(D) Identify the circumstances that are entirely beyond the owner or operator's control and that necessitate additional time to install the identified controls. This may include:

*(1)* Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in § 60.5740b(a)(4)(i);

*(2)* Documentation of any permit delays; or

*(3)* Documentation of delays in construction or permitting of infrastructure (e.g., $CO_2$ pipelines) that is necessary for implementation of the control technology;

(E) Identify a proposed compliance date no later than one year after the applicable compliance date listed in § 60.5740b(a)(4)(i) and, if necessary, updated calendar dates for the increments of progress that have not yet been met.

(ii) The State air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraphs (a)(11)(i)(A) through (E) of this section. The following provisions for approval must be included in the mechanism:

(A) All documentation required as part of this extension must be submitted by the owner or operator of the affected EGU to the State air pollution control agency no later than 6 months prior to the applicable compliance date for that affected EGU.

(B) The owner or operator of the affected EGU must notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request.

(C) The owner or operator of the affected EGU must post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), when they submit the request to the State air pollution control agency.

(D) The owner or operator of the affected EGU must post the State's determination on the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), upon receipt of the determination and, if the request is approved, update the information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the State's approval.

(12) *Short-Term Reliability Mechanism* You may include in your State plan provisions for a short-term reliability mechanism for affected EGUs in your State that operate during a system emergency, as defined in §60.5880b. Such a mechanism must include the components listed in paragraphs (a)(12)(i) through (vi) of this section.

(i) A requirement that the short-term reliability mechanism is available only during system emergencies as defined in § 60.5880b. The State plan must identify the entity or entities that are authorized to issue system emergencies for the State.

(ii) A provision that, for the duration of a documented system emergency, an impacted affected EGU may comply with an emission limitation corresponding to its baseline emission performance rate, as calculated under § 60.5775b(d), in lieu of its otherwise applicable standard of performance. The State plan must clearly identify the alternative emission limitation that corresponds to the affected EGU's baseline emission rate and include it as an enforceable emission limitation that may be applied only during periods of system emergency.

(iii) A requirement that an affected EGU impacted by the system emergency and complying with an alternative emission limitation must provide documentation, as part of its compliance demonstration, of the system emergency according to (a)(12)(iii)(A) through (D) of this section and that it was impacted by that system emergency.

(A) Documentation that the system emergency was in effect from the entity issuing the system emergency and documentation of the exact duration of the event;

(B) Documentation from the entity issuing the system emergency that the system emergency included the affected source/region where the unit was located;

(C) Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator, RTO; and

(D) Data collected during the event including the sum of the $CO_2$ emissions, the sum of the gross energy output, and the resulting $CO_2$ emissions performance rate.

(iv) A requirement to document the hours an affected EGU operated under a system emergency and the enforceable emission limitation, whether the applicable standard of performance or the alternative emission limitation, under which that affected EGU operated during those hours.

(v) A provision that, for the purpose of demonstrating compliance with the applicable standard of performance, the affected EGU would comply with its baseline emissions rate as calculated under § 60.5775b(d) in lieu of its otherwise applicable standard of performance for the hours of operation that correspond to the duration of the event.

(vi) The inclusion of provisions defining the short-term reliability mechanism must be part of the public comment process as part of the State plan's development.

(13) *Reliability Assurance Mechanism* You may include provisions for a reliability assurance mechanism in your State plan. If included, such provisions would allow for one extension, not to exceed 12 months, of the date by which an affected EGU has committed to permanently cease operations, based on a demonstration consistent with this paragraph (a)(13) that operation of the affected EGU is necessary for electric grid reliability.

*(i)* The State plan must require that the reliability assurance mechanism would only be appliable to the following EGUs which, for the purpose of this paragraph (a)(13), are collectively referred to as "eligible EGUs":

(A) Coal-fired steam generating units that are exempt from these emission guidelines pursuant to § 60.5850b(k),

(B) Affected EGUs in the medium-term coal-fired steam-generating subcategory that have enforceable commitments to permanently cease operation before January 1, 2039, in the State plan, and

(C) Affected EGUs that have enforceable dates to permanently cease operation included in the State plan pursuant to § 60.24a(g).

(ii) The date from which an extension would run is the date included in the State plan by which an eligible EGU has committed to permanently cease operation.

(iii) The State plan must provide that an extension is only available to owners or operators of affected EGUs that have satisfied all applicable increments of progress and reporting obligations and milestones in paragraphs (a)(5) and (6) of this section. This includes requiring that the owner or operator of an affected EGU has posted all information relevant to such increments of progress and reporting obligations and milestones on the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10).

(iv) The State plan must provide that any applicable standard of performance for an affected EGU must remain in place during the duration of an extension provided under this mechanism.

(v) The State plan may provide for requests for an extension of up to 12 months without a State plan revision.

(A) For an extension of 6 months or less, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vi) to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(B) For an extension of more than 6 months and up to 12 months, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vii) to the Federal Energy Regulatory Commission (through a process and at an office of the Federal Energy Regulatory Commission's designation) and to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(vi) The State plan must require that to apply for an extension for 6 months or less, described in paragraph (a)(13)(v)(A) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in paragraphs (a)(13)(vi)(A) through (D) of this section no less than 30 days prior to the cease operation date, but no earlier than 12 months prior to the cease operation date.

(A) An analysis of the reliability risk that clearly demonstrates that the eligible EGU is critical to maintaining electric reliability. The analysis must include a projection of the length of time that the EGU is expected to be reliability-critical and the length of the requested extension must be no longer than this period or 6 months, whichever is shorter. In order to show an approvable reliability need, the analysis must clearly demonstrate that an eligible EGU ceasing operation by the date listed in the State plan would cause one or more of the conditions listed in paragraphs (a)(13)(vi)(A)(*1*) or (*2*) of this section. An eligible EGU that has received a Reliability Must Run designation, or equivalent from a Reliability Coordinator or Balancing Authority, would fulfill those conditions.

*(1)* Result in noncompliance with at least one of the mandatory reliability standards approved by FERC; or

*(2)* Would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that the eligible EGU would be needed to maintain the targeted level of resource adequacy.

(B) Certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested. This certification must be accompanied by a written analysis by the relevant planning authority consistent with paragraph (a)(13)(vi)(A) of this section, confirming the asserted reliability risk if the eligible EGU was not in operation. The information from the relevant reliability planning authority must also include any related system-wide or regional analysis and a substantiation of the length of time that the eligible EGU is expected to be reliability critical.

(C) Copies of any written comments from third parties regarding the extension.

(D) Demonstration from the owner or operator of the eligible EGU, grid operator, and other relevant entities of a plan, including appropriate actions to bring on new capacity or transmission, to resolve the underlying reliability issue is leading to the need to employ this reliability assurance mechanism, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(E) Any other information requested by the applicable EPA Regional Administrator or the Federal Energy Regulatory Commission.

(vii) The State plan must require that to apply for an extension longer than 6 months but up to 12 months, described in paragraph (a)(13)(v)(B) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in (a)(13)(vi)(A) through (E) of this section, except that the period of time under (a)(13)(vi)(A) would be 12 months. For requests for extensions longer than 6 months, this application must be submitted to the EPA Regional Administrator no less than 45 days prior to the date for ceasing operation listed in the State plan, but no earlier than 12 months prior to that date.

(viii) The State plan must provide that extensions will only be granted for the period of time that is substantiated by the reliability need and the submitted analysis and documentation, and shall not exceed 12 months in total.

(ix) The State plan must provide that the reliability assurance mechanism shall not be used more than once to extend an eligible EGU's planned cease operation date.

(x) The EPA Regional Administrator may reject the application if the submission is incomplete with respect to the requirements listed in paragraphs (a)(13)(vi)(A) through (E) of this section or if the submission does not adequately support the asserted reliability risk or the period of time for which the eligible EGU is anticipated to be reliability critical.

(b) [Reserved]

**§ 60.5775b What standards of performance must I include in my State plan?**

(a) For each affected EGU, your State plan must include the standard of performance that applies for the affected EGU. A standard of performance for an affected EGU may take the following forms:

(1) A rate-based standard of performance for an individual affected EGU that does not exceed the level calculated through the use of the methods described in § 60.5775b(c) and (d).

(2) A standard of performance in an alternate form, which may apply for affected EGUs in the long-term coal-fired steam generating unit subcategory or the medium-term coal-fired steam generating unit subcategory, as provided for in § 60.5775b(e).

(b) Standard(s) of performance for affected EGUs included under your State plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The State plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.
(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.
(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an standard of performance in the State plan.
(4) An affected EGU's standard of performance is permanent if the standard of performance must be met continuously unless it is replaced by another standard of performance in an approved State plan revision.
(5) An affected EGU's standard of performance is enforceable if:
(i) A technically accurate limitation or requirement, and the time period for the limitation or requirement, are specified;
(ii) Compliance requirements are clearly defined;
(iii) The affected EGUs are responsible for compliance and liable for violations identified;
(iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and
(v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its standard of performance based on its emissions) and secure appropriate corrective actions: in the case of the Administrator, pursuant to CAA sections 113(a)-(h); in the case of a State, pursuant to its State plan, State law or CAA section 304, as applicable; and in the case of third parties, pursuant to CAA section 304.

(c) Methodology for establishing presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term coal-fired steam generating units

(i) BSER is CCS with 90 percent capture of $CO_2$.
(ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb $CO_2$/MWh-gross).
(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb $CO_2$/MWh-gross) from the unit-specific baseline.

(2) Medium-term coal-fired steam generating units.
(i) BSER is natural gas co-firing at 40 percent of the heat input to the unit.
(ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb $CO_2$/MWh-gross).
(iii) Presumptively approvable standard of performance is an emission rate limit defined by a 16 percent reduction in annual emission rate (lb $CO_2$/MWh-gross) from the unit-specific baseline.
(iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, States must account for such preexisting co-firing in adjusting the degree of emission limitation (e.g., for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 12 percent to reflect the preexisting level of natural gas co-firing).

(3) Base load oil-fired steam generating units.
(i) BSER is routine methods of operation and maintenance.
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb $CO_2$/MWh-gross)
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb $CO_2$/MWh-gross.

(4) Intermediate load oil-fired steam generating units.
(i) BSER is routine methods of operation and maintenance.
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross).
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb $CO_2$/MWh-gross.

(5) Low load oil-fired steam generating units.
(i) BSER is uniform fuels.
(ii) Degree of emission limitation is 170 lb $CO_2$/MMBtu.
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 170 lb $CO_2$/MMBtu.

(6) Base load natural gas-fired steam generating units.
(i) BSER is routine methods of operation and maintenance.
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb $CO_2$/MWh-gross).
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb $CO_2$/MWh-gross.

(7) Intermediate load natural gas-fired steam generating units.
(i) BSER is routine methods of operation and maintenance.
(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO2/MWh-gross).
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb $CO_2$/MWh-gross.

(8) Low load natural gas-fired steam generating.
(i) BSER is uniform fuels.
(ii) Degree of emission limitation is 130 lb $CO_2$/MMBtu.
(iii) Presumptively approvable standard of performance is an annual emission rate limit of 130 lb $CO_2$/MMBtu.

(d) Methodology for establishing the unit-specific baseline of emission performance.
(1) A State shall use the $CO_2$ mass emissions and corresponding electricity generation or, for affected EGUs in the low load oil- or natural gas-fired subcategory, heat input data for a given affected EGU

from the most representative continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to **[INSERT DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

(2) For the continuous 8 quarters of data, a State shall divide the total $CO_2$ emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in the low load oil- or natural gas-fired subcategory, total heat input (in the form of MMBtu) over that same time period to calculate baseline $CO_2$ emission performance in lb $CO_2$ per MWh or lb CO2 per MMBtu.

(e) Your State plan may include a standard of performance in an alternate form that differs from the presumptively approvable standard of performance specified in § 60.5775b(a)(1), as follows:

(1) An aggregate rate-based standard of performance (lb $CO_2$/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, provided the standard of performance meets the requirements of paragraph (f) of this section.

(2) A mass-based standard of performance in the form of an annual limit on allowable mass $CO_2$ emissions for an individual affected EGU, provided the standard of performance meets the requirements of paragraph (g) of this section.

(3) A rate-based standard of performance (lb $CO_2$/MWh-gross) implemented through a rate-based emission trading program, such that an affected EGU must meet the specified lb $CO_2$/MWh-gross rate that applies for the affected EGU, and where an affected EGU may surrender compliance instruments denoted in 1 short ton of $CO_2$ to adjust its reported lb $CO_2$/MWh-gross rate for the purpose of demonstrating compliance, provided the standard of performance meets the requirements of paragraph (h) of this section.

(4) A mass-based standard of performance in the form of an annual $CO_2$ budget implemented through a mass-based $CO_2$ emission trading program, where an affected EGU must surrender $CO_2$ allowances in an amount equal to its reported mass $CO_2$ emissions, provided the standard of performance meets the requirements of paragraph (i) of this section.

(f) Where your State plan includes a standard of performance in the form of an aggregate rate-based standard of performance (lb $CO_2$/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section, to each of the affected EGUs that form the group.

(2) Documentation of any assumptions underlying the calculation of the aggregate rate-based standard of performance (lb $CO_2$/MWh-gross).

(3) The process for calculating the aggregate gross generation weighted average emission rate (lb $CO_2$/MWh-gross) at the end of each compliance period, based on the reported emissions (lb $CO_2$) and utilization (MWh-gross) of each of the affected EGUs that form the group.

(4) Measures to implement and enforce the annual aggregate rate-based standard of performance, including the basis for determining owner or operator compliance with the aggregate standard of performance and provisions to address any changes to owners or operators in the course of implementation.

(5) A demonstration of how the application of the aggregate rate-based standard of performance will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(g) Where your State plan includes a standard of performance in the form of an annual limit on allowable mass $CO_2$ emissions for an individual affected EGU, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply to the affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The utilization level used to calculate the mass $CO_2$ limit, by multiplying the assumed utilization level (MWh-gross) by the presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual limit on mass $CO_2$ emissions, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the mass $CO_2$ limit for the affected EGU will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb $CO_2$/MWh-gross) that will also be applied to the affected EGU on an annual basis.

(6) For affected EGUs in the long-term coal-fired steam generating unit subcategory, in lieu of paragraphs (g)(2), (4), and (5) of this section, you may include a presumptively approvable mass $CO_2$ limit based on the product of the rate-based standard of performance (lb $CO_2$/MWh-gross) under paragraph (a)(1) of this section multiplied by a level of utilization (MWh-gross) corresponding to an annual capacity factor of 80 percent for the individual affected EGU with a backstop rate-based emission rate requirement equivalent to a reduction in baseline emission performance of 80 percent on an annual calendar-year basis.

(h) Where your State plan includes a standard of performance in the form of a rate-based standard of performance (lb $CO_2$/MWh-gross) implemented through a rate-based emission trading program, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross) that applies to each of the affected EGUs participating in the rate-based emission trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) Measures to implement and enforce the rate-based emission trading program, including the basis for awarding compliance instruments (denoted in 1 ton of $CO_2$) to an affected EGU that performs better on an annual basis than its rate-based standard of performance, and the process for demonstration of compliance that includes the surrender of such compliance instruments by an affected EGU that exceeds its rate-based standard of performance.

(3) A demonstration of how the use of the rate-based emission trading program will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(i) Where your State plan includes a mass-based standard of performance implemented through a mass-based $CO_2$ emission trading program, where an affected EGU must surrender $CO_2$ allowances in an amount equal to its reported mass $CO_2$ emissions, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply to each affected EGU participating in the trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The calculation of the mass $CO_2$ budget contribution for each participating affected EGU, determined by multiplying the assumed utilization level (MWh-gross) of the affected EGU by its presumptively approvable rate-based standard of performance (lb $CO_2$/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual budget of the mass-based $CO_2$ emission trading program, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the $CO_2$ emission budget for the group of participating affected EGUs will achieve equivalent or better emission performance as would be achieved through the application of a rate-based standard of performance (lb $CO_2$/MWh-gross) that would apply to each participating affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb $CO_2$/MWh-gross) that will also be applied to each participating affected EGU on an annual basis.

(j) In order to use the provisions of § 60.24a(e) through (h) to apply a less stringent standard of performance or longer compliance schedule to an affected EGU based on consideration of electric grid reliability, including resource adequacy, under these emission guidelines, a State must provide the following with its State plan submission:

(1) An analysis of the reliability risk clearly demonstrating that the particular affected EGU is critical to maintaining electric reliability such that requiring it to comply with the applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, a clear demonstration is required that the particular affected EGU would be needed to maintain the targeted level of resource adequacy. The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical and substantiate the basis for applying a less stringent standard of performance or longer compliance schedule consistent with 40 CFR 60.24a(e).

(2) An analysis by the relevant reliability planning authority that corroborates the asserted reliability risk identified in the analysis under paragraph (j)(1) of this section and confirms that requiring the particular affected EGU to comply with its applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region, and also confirms the period of time for which the EGU is projected to be reliability critical.

(3) A certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested.

**§ 60.5780b What compliance dates and compliance periods must I include in my State plan?**

(a) The State plan must include the following compliance dates:

(1) For affected EGUs in the long-term coal-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2032, unless the State has applied a later compliance date pursuant to 40 CFR § 60.24a(e) through (h).

(2) For affected EGUs in the medium-term coal-fired subcategory, the base load oil-fired subcategory, the intermediate load oil-fired steam generating subcategory, the low load oil-fired subcategory, the base load natural gas-fired subcategory, the intermediate load natural gas-fired subcategory, and the low load natural gas-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2030, unless State has applied a later compliance date pursuant to 40 CFR § 60.24a(e) through (h).

(b) The State plan must require affected EGUs to achieve compliance with their applicable standards of performance for each compliance period as defined in § 60.5880b.

**§ 60.5785b What are the timing requirements for submitting my State plan?**

(a) You must submit a State plan or a negative declaration letter with the information required under § 60.5740b by **[INSERT DATE TWO YEARS FROM DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

**§ 60.5790b What is the procedure for revising my State plan?**

EPA-approved State plans can be revised only with approval by the Administrator. The Administrator will approve a State plan revision if it is satisfactory with respect to the applicable requirements of this subpart and all applicable requirements of subpart Ba of this part. If one (or more) of State plan elements in § 60.5740b require revision, the State must submit a State plan revision pursuant to 40 CFR 60.28a.

**§ 60.5795b Commitment to review emission guidelines for coal-fired affected EGUs**

EPA will review and, if appropriate, revise these emission guidelines as they apply to coal-fired steam generating affected EGUs by January 1, 2041. Notwithstanding this commitment, EPA need not review these emission guidelines if the Administrator determines that such review is not appropriate in light of readily available information on their continued appropriateness.

**Applicability of State Plans to Affected EGUs**

**§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?**

(a) This subpart does not directly affect EGU owners or operators in your State, except as provided in § 60.5710b(b). However, affected EGU owners or operators must comply with the State plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the standards of performance contained in this subpart by **[INSERT DATE TWO YEARS FROM DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State.

**§ 60.5845b What affected EGUs must I address in my State plan?**

(a) The EGUs that must be addressed by your State plan are:

(1) Any affected EGUs that were in operation or had commenced construction on or before January 8, 2014;

(2) Coal-fired steam generating units that commenced a modification on or before May 23, 2023.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

**§ 60.5850b What EGUs are excluded from being affected EGUs?**

EGUs that are excluded from being affected EGUs are:

(a) New or reconstructed steam generating units that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Modified natural gas- or oil-fired steam generating units that are subject to subpart TTTT of this part as a result of commencing modification after the subpart TTTT applicability date;

(c) Modified coal-fired steam generating units that are subject to subpart TTTTa of this part as a result of commencing modification after the subpart TTTTa applicability date;

(d) EGUs subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh;

(e) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(f) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(g) Units that serve a generator along with other EGUs), where the effective generation capacity (determined based on a prorated output of the base load rating of each EGU) is 25 MW or less;

(h) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(i) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(j) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(k) Existing coal-fired steam generating units that have demonstrated that they plan to permanently cease operations before January 1, 2032, pursuant to § 60.5740b(a)(9)(ii).

**Recordkeeping and Reporting Requirements**

**§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my State plan for affected EGUs?**

(a) Your State plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (9) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet standards of performance must prepare a monitoring plan in accordance with the applicable provisions in 40 CFR 75.53(g) and (h), 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) For rate-based standards of performance, only "valid operating hours,", *i.e.,* full or partial unit (or stack) operating hours for which:

(i) "Valid data" (as defined in § 60.5880b) 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; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data and

(ii) The corresponding hourly gross energy output value is also valid data (**Note:** For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based standards of performance, 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 (vi) of this section, except as otherwise 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 40 CFR 75.10(a)(3)(i). 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 (CCS)), 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 40 CFR 75.10(a)(3)(iii). 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), this additional $CO_2$ must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If $CO_2$ concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). 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 40 CFR 75.66 for a site-specific default moisture value.

(ii) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), 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 EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of $CO_2$. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(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 40 CFR 75.57(e) and must be reported electronically under § 75.64(a)(6), if required by a State 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 from paragraph (a)(3)(ii) of this section.

(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 40 CFR 75.20 and appendices A and B to part 75 of this chapter.

(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 (a)(4)(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/hr), 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 to part 75 (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) For each "valid operating hour" (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr $CO_2$ mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of $CO_2$. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(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 40 CFR 75.57(e) and must be reported electronically under § 75.64(a)(6), if required by a State 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) from paragraph (a)(4)(iii) of this section.

(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) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see §60.17). 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 gross electric output to determine gross energy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine $P_{gross/net}$ the hourly gross or net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used 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.

(iv) Calculate $P_{gross/net}$ for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [\ (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\ ]$$

WHERE:

$P_{GROSS/NET}$ = GROSS OR NET ENERGY OUTPUT OF YOUR AFFECTED EGU FOR EACH VALID OPERATING HOUR (AS DEFINED IN 60.5860b(a)(2)) IN MWh.
$(PE)_{ST}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STEAM TURBINES IN MWh.
$(PE)_{CT}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF STATIONARY COMBUSTION TURBINE(S) IN MWh.
$(PE)_{IE}$ = ELECTRIC ENERGY OUTPUT PLUS MECHANICAL ENERGY OUTPUT (IF ANY) OF YOUR AFFECTED EGU'S INTEGRATED EQUIPMENT THAT PROVIDES ELECTRICITY OR MECHANICAL ENERGY TO THE AFFECTED EGU OR AUXILIARY EQUIPMENT IN MWh.
$(PE)_{A}$ = ELECTRIC ENERGY USED FOR ANY AUXILIARY LOADS IN MWh.
$(PT)_{PS}$ = USEFUL THERMAL OUTPUT OF STEAM (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) THAT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU. THIS IS CALCULATED USING THE EQUATION SPECIFIED IN PARAGRAPH (a)(5)(V) OF THIS SECTION IN MWh.
$(PT)_{HR}$ = NON-STEAM USEFUL THERMAL OUTPUT (MEASURED RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM HEAT RECOVERY THAT IS USED FOR APPLICATIONS OTHER THAN STEAM GENERATION OR PERFORMANCE ENHANCEMENT OF THE AFFECTED EGU IN MWh.
$(PT)_{IE}$ = USEFUL THERMAL OUTPUT (RELATIVE TO SATP CONDITIONS, AS APPLICABLE) FROM ANY INTEGRATED EQUIPMENT IS USED FOR APPLICATIONS THAT DO NOT GENERATE ADDITIONAL STEAM, ELECTRICITY, PRODUCE MECHANICAL ENERGY OUTPUT, OR ENHANCE THE PERFORMANCE OF THE AFFECTED EGU IN MWh.
TDF = ELECTRIC TRANSMISSION AND DISTRIBUTION FACTOR OF 0.95 FOR A COMBINED HEAT AND POWER AFFECTED EGU WHERE AT LEAST ON AN ANNUAL BASIS 20.0 PERCENT OF THE TOTAL GROSS OR NET ENERGY OUTPUT CONSISTS OF ELECTRIC OR DIRECT MECHANICAL OUTPUT AND 20.0 PERCENT OF THE TOTAL GROSS OR NET ENERGY OUTPUT CONSIST OF USEFUL THERMAL OUTPUT ON A 12-OPERATING MONTH ROLLING AVERAGE BASIS, OR 1.0 FOR ALL OTHER AFFECTED EGUS.

(v) 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:

$Q_M$ = MEASURED STEAM FLOW IN KILOGRAMS (KG) (OR POUNDS (LBS)) FOR THE OPERATING HOUR.
H = ENTHALPY OF THE STEAM AT MEASURED TEMPERATURE AND PRESSURE (RELATIVE TO SATP CONDITIONS OR THE ENERGY IN THE CONDENSATE RETURN LINE, AS APPLICABLE) IN JOULES PER KILOGRAM (J/KG) (OR BTU/LB).
CF = CONVERSION FACTOR OF 3.6 X $10^{9}$ J/MWH OR 3.413 X $10^{6}$ BTU/MWh.

(vi) For rate-based standards, sum all of the values of $P_{gross/net}$ for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total $CO_2$ mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the $P_{gross/net}$ values for the valid operating hours to determine the $CO_2$ emissions rate (lb/gross or net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section share a common exhaust gas stack and are subject to the same emissions standard, 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, the hourly gross or net electric output for the common stack must be the sum of the hourly gross or net electric output of the individual affected EGUs and the operating time must be expressed as “stack operating hours” (as defined in 40 CFR 72.2).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) 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 40 CFR 72.2) 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 gross or net energy output for the affected EGU.

(8) Consistent with § 60.5775b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(9) The owner or operator of an affected EGU must measure and report monthly fuel usage for each affected source subject to standards of performance with the information in paragraphs (9)(i) through (iii) of this section:

(i) The calendar month during which the fuel was used;
(ii) Each type of fuel used during the calendar month of the compliance period; and
(iii) Quantity of each type of fuel combusted in each calendar month in the compliance period with units of measure.

(b) Your State plan must require the owner or operator of each affected EGU covered by your State plan to maintain the records, for at least 5 years following the date of each 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 occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's standard of performance under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (b) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(c) Your State plan must require the owner or operator of an affected EGU covered by your State plan to include in a report submitted to you the information in paragraphs (c)(1) through (3) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly $CO_2$ emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) 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;

(ii) The gross or net electric output and the gross or net energy output ($P_{gross/net}$) values for each valid operating hour;

(iii) The calculated $CO_2$ mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly gross or net energy output values and the sum of the hourly $CO_2$ mass emissions values, for all of the valid operating hours; and

(v) The calculated $CO_2$ mass emission rate (lbs/gross or net MWh).

(3) For each affected EGU the report must also include the applicable standard of performance and demonstration that it met the standard of performance. An owner or operator must also include in the report the affected EGU's calculated emission performance as a $CO_2$ emission rate in units of the standard of performance.

(d) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a State plan that are required under § 60.5740b if applicable.

(e) If an affected EGU captures $CO_2$ to meet the applicable standard of performance, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured $CO_2$ to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured $CO_2$ to a facility that has received an innovative technology waiver from the EPA pursuant to paragraph (f) of this section.

(f) Any person may request the Administrator to issue a waiver of the requirement that captured $CO_2$ from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured $CO_2$ as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than $CO_2$, and permanence of the $CO_2$ storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured $CO_2$ without release. The

Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of $CO_2$ or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

### § 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of State plan components, State plan requirements, supporting documentation, and the status of meeting the State plan requirements defined in the State plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that are used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly $CO_2$ emissions and gross generation or heat input information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records for a minimum of 10 years from the date the record is used to determine compliance with an emissions standard or State plan requirement. Each record must be in a form suitable and readily available for expeditious review.

(e) If your State plan includes provisions for the compliance date extension, described in § 60.5740b(a)(11), you must keep records of the information required in § 60.5740b(a)(11)(i) from affected EGUs that use the compliance date extension.

(f) If your State plan includes provisions for the short-term reliability mechanism, as described in § 60.5740b(a)(12), you must keep records of the information required in § 60.5740b(a)(12)(iii) from affected EGUs that use the short-term reliability mechanism.

(g) If your State plan includes provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13), you must keep records of the information required in § 60.5740b(a)(13)(vi) from affected EGUs that use the reliability assurance mechanism.

### § 60.5870b What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f) of this part, you must report the information in paragraph (b) of this section

(b) You must submit an annual report to the EPA that must include the information in paragraphs (b)(1) through (10) of this section. For each calendar year reporting period, the report must be submitted by March 1 of the following year.

*(1)* The report must include the emissions performance achieved by each affected EGU during the reporting period and identification of whether each affected EGU is in compliance with its standard of performance during the compliance period, as specified in the State plan.

(2) The report must include, for each affected EGU, a comparison of the $CO_2$ standard of performance in the State plan versus the actual $CO_2$ emission performance achieved.

(3) The report must include, for each affected EGU, the sum of the $CO_2$ emissions, the sum of the gross energy output, and the sum of the heat input for each fuel type.

(4) Enforcement actions initiated against affected EGUs during the reporting period, under any standard of performance or compliance schedule of the State plan.

(5) Identification of the achievement of any increment of progress required by the applicable State plan during the reporting period.

(6) Identification of designated facilities that have ceased operation during the reporting period.

(7) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of State plan development but began operation during the reporting period.

(8) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(9) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

(10) The report must include all other required information, as specified in your State plan according to § 60.5740b.

(c) If you include provisions for the compliance date extension, described in § 60.5740b(a)(11), in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(11)(i).

(d) If you include provisions for the short-term reliability mechanism, described in § 60.5740b(a)(12), in your State plan, you must report to the EPA the following information for each event, listed in § 60.5740b(a)(12)(iii).

(e) If you include provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13) in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(13)(vi).

**§ 60.5875b How do I submit information required by these emission guidelines to the EPA?**

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any State plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through the EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the **[INSERT DATE TWO YEARS FROM DATE OF PUBLICATION IN THE FEDERAL REGISTER]** deadline for State plan submittal so that the official will have the ability to submit the initial or final State plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all State plan components designated as federally enforceable must also be submitted in an editable version. Following initial State plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable State plan components, including State plan backstop measures. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable State plan components. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

**§ 60.5876b What are the recordkeeping and reporting requirements for EGUs that have committed to permanently cease operations by January 1, 2032?**

(a) If you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must maintain records for and submit the reports listed in paragraphs (a)(1) through (3) of this section according to the electronic reporting requirements in paragraph (b) of this section.

(1) Five years before any planned date to permanently cease operations or by the date upon which the State plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the information in paragraphs (a)(1)(i) and (ii) of this section.

(i) A summary of the process steps required for the EGU to permanently cease operation by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, e.g., initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's relevant reliability authority.

(ii) Supporting regulatory documents, which include those listed in paragraphs (a)(1)(ii)(A) through (G) of this section:

(A) Correspondence and official filings with the relevant regional RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority;

(B) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(C) Any filings pertaining to the affected EGU with the SEC or notices to investors, including but not limited to references in forms 10-K and 10-Q, in which plans for the EGU are mentioned;

(D) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(E) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(F) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(G) Any notification to or from an RTO, Independent System Operator, or relevant reliability authority altering the timing of deactivation of the EGU.

(2) For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the owner or operator of the EGU must submit an annual status report to the EPA that includes the information listed in paragraphs (a)(2)(i) and (ii) of this section:

(i) Progress on each of the identified process steps identified in the initial report as described in paragraph (a)(1)(i) of this section; and

(ii) Supporting regulatory documents, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate progress toward all steps described in paragraph (a)(1)(i) of this section.

(3) The owner or operator must submit a final report to the EPA no later than 6 months following its committed closure date. This report must document any actions that the EGU has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(b) Beginning **[INSERT DATE 6 MONTHS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, if you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must submit all the information required in paragraph (a) of this section in a Permanent Cessation of Operation report in PDF format following the procedures specified in paragraph (c) of this section.

(c) If you are required to submit notifications or reports following the procedure specified in this paragraph (c), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (c)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (c).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqpscbi@epa.gov, and as described above, should include clear CBI markings and be flagged to the attention of the Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. All other files should also be sent to the attention of the Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(d) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(e) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.
(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.
(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.
(3) The outage may be planned or unplanned.
(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
(5) You must provide to the Administrator a written description identifying:
(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
(iii) A description of measures taken or to be taken to minimize the delay in reporting; and
(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.
(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure*, you must meet the requirements outlined in paragraphs (f)(1) through (5) of this section.
(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (e.g., hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (e.g., large scale power outage).
(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
(3) You must provide to the Administrator:
(i) A written description of the *force majeure* event;
(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;
(iii) A description of measures taken or to be taken to minimize the delay in reporting; and
(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.
(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(g) Alternatives to any electronic reporting required by this subpart must be approved by the Administrator.

**Definitions**

**§ 60.5880b What definitions apply to this subpart?**

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

*Affected electric generating unit* or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

*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.

*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, as defined below. For a stationary combustion turbine or IGCC, *base load rating* includes the heat input from duct burners.

*Coal-fired steam generating unit* means an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.

*Combined cycle unit* means 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 source.

*Compliance period* means an annual (calendar year) period for an affected EGU to comply with a standard of performance.

*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.

*Fossil fuel* means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

*Gross energy output* means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or

mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

*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.

*Integrated gasification combined cycle facility* or *IGCC* 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.

*ISO conditions* means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

*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 must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

*Nameplate capacity* means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

*Natural gas* means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable $CO_2$ content or heating value.

*Natural gas-fired steam generating unit* means an electric utility steam generating unit meeting the definition of “fossil fuel-fired,” that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any calendar year after December 31, 2029.

*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 standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(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).

*Oil-fired steam generating unit* means an electric utility steam generating unit meeting the definition of “fossil fuel-fired” that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

*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.

*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 emission 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. A stationary combustion turbine that burns any solid fuel directly 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.

*System Emergency* means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2, or its successor.

*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.

*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 40 CFR 75.20 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 2.1.4, 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).

*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.