

notify the Administrator of, each unit's allocation of CAIR NO<sub>x</sub> Ozone Season allowances by April 30, 2007 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the 4th year after the year of the notification deadline.

(D) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the permitting authority will determine, and notify the Administrator of, each unit's allocation of CAIR NO<sub>x</sub> Ozone Season allowances by July 31 of the year for which the CAIR NO<sub>x</sub> Ozone Season allowances are allocated.

(3) The State may adopt CAIR opt-in unit provisions as follows:

(i) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO<sub>x</sub> Ozone Season allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied;

(ii) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO<sub>x</sub> Ozone Season allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.388(b) of this chapter and the provisions of subpart IIII of part 96 of this chapter that apply only to units covered by § 96.388(b) of this chapter; or

(iii) Provisions for applications for CAIR opt-in units, including provisions for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation

and recordation of CAIR NO<sub>x</sub> allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.388(c) of this chapter and the provisions of subpart IIII of part 96 of this chapter that apply only to units covered by § 96.388(c) of this chapter.

[70 FR 25319, May 12, 2005, as amended at 71 FR 25301, 25370, Apr. 28, 2006; 71 FR 74793, Dec. 13, 2006; 72 FR 59203, Oct. 19, 2007; 74 FR 56726, Nov. 3, 2009]

**§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.**

(a)(1) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting SO<sub>2</sub> in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles (PM<sub>2.5</sub>) NAAQS.

(2) Notwithstanding the other provisions of this section, such provisions are not applicable as they relate to the State of Minnesota as of December 3, 2009.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) The following States are subject to the requirements of this section: Alabama, Delaware, Florida, Georgia,

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Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the District of Columbia.

(d)(1) The SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU SO<sub>2</sub> Budget, if applicable, and achieve the State's Annual Non-EGU SO<sub>2</sub> Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU SO<sub>2</sub> Budget and Annual Non-EGU SO<sub>2</sub> Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU SO<sub>2</sub> Budget for the State is defined as the total amount of SO<sub>2</sub> emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU SO<sub>2</sub> Budget for the State shall not exceed the amount, during

the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non-EGU SO<sub>2</sub> Reduction Requirement, if applicable, is defined as the total amount of SO<sub>2</sub> emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, then the State's Annual Non-EGU SO<sub>2</sub> Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Annual Non-EGU SO<sub>2</sub> Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU SO<sub>2</sub> Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU SO<sub>2</sub> Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non-EGU SO<sub>2</sub> Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only EGUs, the amount of the Annual EGU SO<sub>2</sub> Budget, in tons of SO<sub>2</sub> per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU SO <sub>2</sub> budget for 2010–2014 (tons)	Annual EGU SO <sub>2</sub> budget for 2015 and thereafter (tons)
Alabama .....	157,582	110,307
Delaware .....	22,411	15,687
District of Columbia .....	708	495
Florida .....	253,450	177,415
Georgia .....	213,057	149,140
Illinois .....	192,671	134,869
Indiana .....	254,599	178,219
Iowa .....	64,095	44,866
Kentucky .....	188,773	132,141
Louisiana .....	59,948	41,963
Maryland .....	70,697	49,488
Michigan .....	178,605	125,024
Minnesota .....	49,987	34,991

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State	Annual EGU SO <sub>2</sub> budget for 2010–2014 (tons)	Annual EGU SO <sub>2</sub> budget for 2015 and thereafter (tons)
Mississippi .....	33,763	23,634
Missouri .....	137,214	96,050
New Jersey .....	32,392	22,674
New York .....	135,139	94,597
North Carolina .....	137,342	96,139
Ohio .....	333,520	233,464
Pennsylvania .....	275,990	193,193
South Carolina .....	57,271	40,089
Tennessee .....	137,216	96,051
Texas .....	320,946	224,662
Virginia .....	63,478	44,435
West Virginia .....	215,881	151,117
Wisconsin .....	87,264	61,085

(3) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, the amount of the Annual Non-EGU SO<sub>2</sub> Reduction Requirement, in tons of SO<sub>2</sub> per year, shall be determined, for the State for 2010 and thereafter, by subtracting the amount of the State's Annual EGU SO<sub>2</sub> Budget for the appropriate year, specified in paragraph (e)(2) of this section, from an amount equal to 2 times the State's Annual EGU SO<sub>2</sub> Budget for 2010 through 2014, specified in paragraph (e)(2) of this section.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual SO<sub>2</sub> mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual SO<sub>2</sub> mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual SO<sub>2</sub> mass emissions cap on all such sources in the State, or the State must demonstrate why such emissions cap is not practicable, and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2010 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non-EGU SO<sub>2</sub> Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of SO<sub>2</sub> mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with part 75 of this chapter, if the source category is subject to part 75 monitoring requirements in accordance with part 75 of this chapter.

(B) In the absence of monitoring data in accordance with part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of SO<sub>2</sub> mass emissions from the source category in the years 2010 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2010 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP

revision to meet the SO<sub>2</sub> emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2010 or 2015, as appropriate.

(iii) A projection of SO<sub>2</sub> mass emissions in 2010 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2010 and 2015 SO<sub>2</sub> emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2010 and 2015, respectively,

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from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2010 and 2015, respectively, may be credited towards the State's Annual Non-EGU SO<sub>2</sub> Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section, as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of SO<sub>2</sub> emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, record-keeping, and reporting provisions of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in para-

graph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, record-keeping, and reporting provisions of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter.

(j) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU SO<sub>2</sub> Budget or the Annual Non-EGU SO<sub>2</sub> Reduction Requirement, as applicable, under paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require record-keeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3)

and (4) of this section may be delegated to the State under section 114 of the CAA.

(1)(1) A SIP revision may assign legal authority to local agencies in accordance with §51.232.

(2) Each SIP revision must comply with §51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with §51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in §51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAA through III of part 96 of this chapter (CAIR SO<sub>2</sub> Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations. Before January 1, 2009, a State's regulations shall be considered to be substantively identical to subparts AAA through III of part 96 of the chapter, or differing substantively only as set forth in paragraph (o)(2) of this section, regardless of whether the State's regulations include the definition of "Biomass", paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in §96.202 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a SIP revision that revises the State's regulations to include such provisions. Submission to the Administrator of a SIP revision that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2009.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter only as follows, then the emissions trading pro-

gram is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR SO<sub>2</sub> opt-in provisions of subpart III of this part and the provisions applicable only to CAIR SO<sub>2</sub> opt-in units in subparts AAA through HHH of this part.

(ii) The State may decline to adopt the CAIR SO<sub>2</sub> opt-in provisions of §96.288(b) of this chapter and the provisions of subpart III of this part applicable only to CAIR SO<sub>2</sub> opt-in units under §96.288(b).

(iii) The State may decline to adopt the CAIR SO<sub>2</sub> opt-in provisions of §96.288(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR SO<sub>2</sub> opt-in units under §96.288(c).

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with §96.123 (o)(1) or (2) or (aa)(1) or (2) of this chapter.

(4) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the SO<sub>2</sub> allowances issued under such emissions trading program shall not, and the SIP revision shall state that such SO<sub>2</sub> allowances shall not, qualify as CAIR SO<sub>2</sub> allowances under any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(p) If a State's SIP revision does not contain an emissions trading program approved under paragraph (o)(1) or (2) of this section but contains control measures on EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section:

(1) The SIP revision shall provide, for each year that the State has such obligation, for the permanent retirement of an amount of Acid Rain allowances allocated to sources in the State for

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that year and not deducted by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section, equal to the difference between—

(A) The total amount of Acid Rain allowances allocated under the Acid Rain Program to the sources in the State for that year; and

(B) If the State's SIP revision contains only control measures on EGUs, the State's Annual EGU SO<sub>2</sub> Budget for the appropriate period as specified in paragraph (e)(2) of this section or, if the State's SIP revision contains control measures on EGUs and non-EGUs, the State's Annual EGU SO<sub>2</sub> Budget for the appropriate period as specified in the SIP revision.

(2) The SIP revision providing for permanent retirement of Acid Rain allowances under paragraph (p)(1) of this section must ensure that such allowances are not available for deduction by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(q) The terms used in this section shall have the following meanings:

*Acid Rain allowance* means a limited authorization issued by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during the specified year or any year thereafter, except as otherwise provided by the Administrator.

*Acid Rain Program* means a multi-State sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

*Administrator* means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

*Allocate or allocation* means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source or other entity.

*Biomass* means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchutable for other purposes, that is segregated from other nonmerchutable material, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

*Boiler* means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

*Bottoming-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

*Clean Air Act or CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

*Cogeneration unit* means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than

45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

*Combustion turbine* means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

*Commence operation* means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

*Electric generating unit* or *EGU* means:

(1)(i) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(ii) If a stationary boiler or stationary combustion turbine that, under paragraph (1)(i) of this section, is not an electric generating unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become an electric generating unit as provided in paragraph (1)(i) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(2) A unit that meets the requirements set forth in paragraphs (2)(i)(A), (2)(ii)(A), or (2)(ii)(B) of this definition paragraph shall not be an electric generating unit:

(i)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition:

(1) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(2) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(B) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (2)(i)(A) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (2)(i)(A)(2) of this section.

(ii)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation before January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for 1985-1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(B) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation on or after January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).



(C) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (2)(ii)(A) or (B) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

*Fossil fuel* means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

*Fossil-fuel-fired* means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

*Generator* means a device that produces electricity.

*Maximum design heat input* means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

*NAAQS* means National Ambient Air Quality Standard.

*Nameplate capacity* means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

*Non-EGU* means a source of SO<sub>2</sub> emissions that is not an EGU.

*Potential electrical output capacity* means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

*Sequential use of energy* means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

*Solid waste incineration unit* means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

*Topping-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

*Total energy input* means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

*Total energy output* means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$\text{LHV} = \text{HHV} - 10.55(\text{W} + 9\text{H})$$

Where:

LHV = lower heating value of fuel in Btu/lb,  
 HHV = higher heating value of fuel in Btu/lb,  
 W = Weight % of moisture in fuel, and  
 H = Weight % of hydrogen in fuel.

*Unit* means a stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel-fired combustion turbine.

*Useful power* means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel

combusted at the unit and any on-site emission controls).

*Useful thermal energy* means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

*Utility power distribution system* means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

(r) Notwithstanding any other provision of this section, a State may adopt, and include in a SIP revision submitted by March 31, 2007, regulations relating to the Federal CAIR SO<sub>2</sub> Trading Program under subparts AAA through HHH of part 97 of this chapter as follows. The State may adopt the following CAIR opt-in unit provisions:

(1) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO<sub>2</sub> allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied;

(2) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO<sub>2</sub> allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.288(b) of

this chapter and the provisions of subpart III of part 96 of this chapter that apply only to units covered by § 96.288(b) of this chapter; or

(3) Provisions for applications for CAIR opt-in units, including provisions for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO<sub>2</sub> allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.288(c) of this chapter and the provisions of subpart III of part 96 of this chapter that apply only to units covered by § 96.288(c) of this chapter.

[70 FR 25328, May 12, 2005, as amended at 71 FR 25302, 25372, Apr. 28, 2006; 71 FR 74793, Dec. 13, 2006; 72 FR 59204, Oct. 19, 2007; 74 FR 56726, Nov. 3, 2009]

**§51.125 Emissions reporting requirements for SIP revisions relating to budgets for SO<sub>2</sub> and NO<sub>x</sub> emissions.**

(a) For its transport SIP revision under §51.123 and/or 51.124, each State must submit to EPA SO<sub>2</sub> and/or NO<sub>x</sub> emissions data as described in this section.

(1) Alabama, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the District of Columbia must report annual (12 months) emissions of SO<sub>2</sub> and NO<sub>x</sub>.

(2) Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin and the District of Columbia must report ozone season (May 1 through September 30) emissions of NO<sub>x</sub>.