ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[FRL–7985–7; E-Docket ID No. OAR–2005–0163]

RIN 2060–AN28

Prevention of Significant Deterioration, Nonattainment New Source Review, and New Source Performance Standards: Emissions Test for Electric Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA (we) is proposing to revise the emissions test for existing electric generating units (EGUs) that are subject to the regulations governing the Prevention of Significant Deterioration (PSD) and nonattainment major New Source Review (NSR) programs (collectively ''NSR'') mandated by parts C and D of title I of the Clean Air Act (CAA or Act). The revised emissions test is the same as that in the New Source Performance Standards (NSPS) program under CAA section 111(a)(4). For existing EGUs, we are proposing to compare the maximum hourly emissions achievable at that unit during the past 5 years to the maximum hourly emissions achievable at that unit after the change to determine whether an emissions increase would occur. Alternatively, we are soliciting public comment on a major NSR emissions test for existing EGUs that would compare maximum hourly emissions achieved before a change to the maximum hourly emissions achieved after the change. We are also soliciting public comment on adopting an NSR emissions test based on mass of emissions per unit of energy output. In addition, we are soliciting comment on whether to revise the NSPS regulations to include a maximum achieved emissions test or an output-based emissions test, either in lieu of or in addition to the maximum achievable hourly emissions test. Today's proposal would not affect new EGUs, which would continue to be subject to major NSR preconstruction review and to the NSPS program. The proposed rule would only apply prospectively to changes at existing EGUs potentially covered by major NSR and the NSPS programs.

These proposed regulations interpret CAA section 111(a)(4), in the context of NSR and NSPS, for physical changes and changes in the method of operation at existing EGUs. The proposed regulations would establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs. The proposed regulations would also promote the safety, reliability, and efficiency of EGUs.

DATES: *Comments.* Comments must be received on or before December 19, 2005.

Public Hearing. If anyone contacts us requesting to speak at a public hearing November 9, 2005, we will hold a public hearing approximately 30 days after publication in the **Federal Register**.

ADDRESSES: Submit your comments, identified by Docket ID No. OAR–2005–0163 by one of the following methods:

- Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- Agency Web site: *http://www.epa.gov/edocket.* EDOCKET, EPA's electronic public docket and comment system, is EPA's preferred method for receiving comments. Follow the on-line instructions for submitting comments.
- E-mail: *a-and-r-docket@epamail.epa.gov.*
- Fax: 202–566–1741.
- Mail: Attention Docket ID No. OAR–2005–0163, U.S. Environmental Protection Agency, EPA West (Air Docket), 1200 Pennsylvania Avenue, Northwest, Mail Code: 6102T, Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for OMB, 725 17th Street, Northwest, Washington, DC 20503.
- Hand Delivery: U.S. Environmental Protection Agency, EPA West (Air Docket), 1301 Constitution Avenue, Northwest, Room B102, Washington, DC 20004, Attention Docket ID No. OAR–2005–0163. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. OAR–2005–0163. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.epa.gov/edocket,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through EDOCKET, regulations.gov, or e-mail. The EPA EDOCKET and the Federal regulations.gov Web sites are ''anonymous access'' systems, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through EDOCKET or regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, avoid any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit EDOCKET on-line or see the **Federal Register** of May 31, 2002 (67 FR 38102). For additional instructions on submitting comments, go to section I..B. of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the U.S. Environmental Protection Agency, EPA West (Air Docket), 1301 Constitution Avenue, Northwest, Room B102, Washington, DC. Attention Docket ID No. OAR–2005–0163. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Janet McDonald, Information Transfer and Program Integration Division (C339–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541–1450; fax number : (919) 541–5509, or electronic mail at *mcdonald.janet@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. What Are the Regulated Entities?

Entities potentially affected by the subject rule for today's action are fossil-fuel fired boilers, turbines, and internal combustion engines, including those that serve generators producing electricity, generate steam or cogenerate electricity and steam.

Industry group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122.
Federal government	22112[1]	Fossil-fuel fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	22112	Fossil-fuel fired electric utility steam generating units owned by municipalities. Fossil-fuel fired electric utility steam generating units in Indian country.

[a] Standard Industrial Classification.
[b] North American Industry Classification System.
[1] Establishments owned and operated by Federal, State, or local government are classified according to the activity in which they are engaged.

Entities potentially affected by the subject rule for today's action also include State, local, and tribal governments.

B. How Should I Submit CBI to the Agency?

1. Submitting CBI. Do not submit this information that you consider to be CBI electronically through EDOCKET, regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark on the CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Also, send an additional copy clearly marked as above not only to the Air Docket but to: Mr. Roberto Morales, OAQPS Document Control Officer, (C339–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, Attention Docket ID No. OAR–2005–0163.

C. What Should I Consider as I Prepare My Comments for EPA?

When submitting comments, remember to:

1. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

2. Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

3. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

4. Describe any assumptions and provide any technical information and/or data that you used.

5. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

6. Provide specific examples to illustrate your concerns, and suggest alternatives.

7. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

8. Make sure to submit your comments by the comment period deadline identified.

D. How Can I Find Information About a Possible Public Hearing?

People interested in presenting oral testimony or inquiring as to whether a hearing is to be held should contact Ms. Chandra Kennedy, Integrated Implementation Group, Information Transfer and Program Integration Division (C339–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number (919) 541–5319, at least 2 days in advance of the public hearing. People interested in attending the public hearing should also contact Ms. Kennedy to verify the time, date, and location of the hearing. The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning these proposed changes.

E. How Is This Preamble Organized?

The information presented in this preamble is organized as follows:

II. Overview

In today's action, we are proposing to revise the emissions test for existing EGUs that are subject to the regulations in the major NSR programs mandated by parts C and D of title I of the CAA. The revised emissions test is the same as that in the NSPS under CAA section

111. For existing EGUs, we are proposing to compare the maximum hourly emissions achievable at that unit during the past 5 years to the maximum hourly emissions achievable at that unit after the change to determine whether an emissions increase would occur. This maximum achievable hourly emissions test would apply to emissions from existing EGUs. Today's proposal would not affect new EGUs, which would continue to be subject to major NSR preconstruction review. These proposed regulations interpret CAA section 111(a)(4), in the context of NSR, for physical changes and changes in the method of operation at existing EGUs.

Alternatively, we are soliciting public comment on a major NSR emissions test for existing EGUs that would compare maximum hourly emissions achieved before a change to the maximum hourly emissions achieved after the change. The test based on maximum achievable hourly emissions is our preferred test, but we are also soliciting comment on this test based on maximum achieved hourly emissions.

We also request comment on adopting an NSR emissions test based on mass of emissions per unit of energy output, such as lb/MW hour or nanograms per Joule. As we discuss in more detail in Section IV.B.3. of this preamble, an output-based emissions test encourages use of energy efficient EGU that displace less efficient, more polluting units.

We also request comment on extending the proposed emission increase tests to the NSPS program. Specifically, we are also soliciting comment on whether to revise 40 CFR 60.14 to include a maximum achieved emissions test or an output-based emissions test, either in lieu of or in addition to the maximum achievable hourly emissions test in the current regulations.

The proposed regulations would establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs. The need to provide national consistency for EGUs is apparent following a recent Fourth Circuit Court of Appeals decision. On June 15, 2005, the Fourth Circuit Court of Appeals ruled that EPA must use a consistent definition of the term ''modification'' for the purposes of both the NSPS program under section 111 of the Act and NSR program under parts C and D of the Act. The Court further ruled that because EPA had promulgated NSPS regulations with a test based on increases in a plant's hourly rate of emissions prior to enactment of the PSD provision of the statute, and the PSD regulations had to be interpreted congruently to include the same hourly test.[2] See *United States* v. *Duke Energy Corp.,* No. 04–1763 (4th Cir. June 15, 2005). The Fourth Circuit denied the United States' petition for rehearing concerning this decision, although the deadline for filing a petition for certiorari has not yet run.[3] The NSPS program applies a maximum achievable hourly emissions rate test to determine whether a physical change or change in the operation (physical or operational change) results in an emissions increase. Once the mandate is issued in the *Duke Energy* case, the NSPS test will apply in all Fourth Circuit States, unless the NSR test in those States' implementation plans is more stringent than the NSPS test. This holding creates a potential disparity in the way we interpret the program in States in the Fourth Circuit compared to States in other Circuits in the country. By finalizing today's proposed rule, we would provide nationwide consistency in how States implement the major NSR program for EGUs and establish a test consistent with the Fourth Circuit's holding in *Duke Energy.* We would also make a uniform emissions test under the NSPS and NSR programs for existing EGUs.

We believe a uniform national emissions test has particular merit considering the substantial emissions reductions from other CAA requirements that are more efficient than major NSR, which we describe in Section III of this preamble. Furthermore, the proposed regulations allow owner/operators to make changes that, without increasing existing capacity, promote the safety, reliability, and efficiency of EGUs. The current major NSR approach discourages sources from replacing components, and encourages them to replace components with inferior components or to artificially constrain production in other ways. This behavior does not advance the central policy goals of the major NSR program as applied to existing sources. The central policy goal is not to limit productive capacity of major stationary sources, but rather to ensure that they will install state-of-the-art pollution controls at a juncture where it otherwise makes sense to do so. We also do not believe the outcomes produced by the approach we have been taking have significant environmental benefits compared with the approach we are proposing today.

In the following sections of this preamble, we provide details on the EGU requirements and emissions, today's proposed rule, and the legal basis for our proposal. We request public comment on all aspects of today's proposed action. We intend to publish a supplemental proposal in the near future that will include proposed regulatory language, as well as additional data and information.

III. Background on EGU Requirements and Emissions

In this section we describe the regulatory history and programs applying to EGUs. These include the command-and-control strategies such as NSPS and major NSR that went into effect before 1990, as well as the more efficient programs since 1990 that have achieved substantial reductions in EGU emissions.

A. SO_2 and NO_X Requirements Before 1990

Beginning in 1970, the CAA and our implementing regulations have imposed numerous requirements on sulfur dioxide (SO_2) and nitrous oxide (NO_X) emissions from utilities. In the early regulatory history under the CAA, these requirements were limited to the NSPS and major NSR programs. The NSPS program applies to EGUs and other stationary sources of pollutants, including SO_2, NO_X, particulate matter (PM), carbon monoxide (CO), ozone, and lead, among others. The Act required us to develop NSPS for a number of source categories, including coal-fired power plants. The first NSPS for EGUs (40 CFR part 60, subpart D) required new units to limit SO_2 emissions either by using scrubbers or by using low sulfur coal. It required limits on NO_X emissions through the use of low NO_X burners. A new NSPS (40 CFR part 60, subpart Da), promulgated in 1978, tightened the standards for SO_2, requiring scrubbers on all new units.

Federal preconstruction permitting for EGUs and other new stationary sources was considered in 1970, but not added to the CAA until it was amended again in 1977. The Federal preconstruction program for major stationary sources is commonly called the major NSR program. As we discuss in further detail in Section V.B. of this preamble, the major NSR program required emission limitations based on Best Available Control Technology (BACT) and Lowest

[2] The Court allowed for the possibility that EPA may change the test that applies through future rulemaking. See item 0015 in E-Docket OAR–2005–0163.

[3] We continue to respectfully disagree with the Fourth Circuit's decision in *Duke Energy* (item 0015 in E-Docket OAR–2005–0163) and continue to believe that we have the authority to define ''modification'' differently in the NSPS and NSR programs. However, we believe that the action that we proposed today is an appropriate exercise of our discretion.

Achievable Emission Rate (LAER) controls.

The NSPS and major NSR programs imposed limitations on EGU SO_2 and NO_X emissions at individual sources based on control technology performance. They did not set specific limits on the total regional or national emissions from EGUs. Neither of these programs apply to EGUs that were already in existence before the regulations were effective, unless these EGUs choose to modify. Thus, neither program applies to all EGUs. Before 1990, however, the major NSR program did provide States one of the few opportunities to mitigate rising levels of air pollution through regulation of possible emissions increases from existing sources. Therefore, the program was consistent with Congress' directive that the major NSR program be tailored to balance the ''need for environmental protection against the desires to encourage economic growth.''

B. SO_2 and NO_X Requirements After 1990

The 1990 Amendments to the CAA imposed a number of new requirements on EGUs. The Acid Rain program, established under title IV of the 1990 CAA Amendments, requires major reductions of SO_2 and NO_X emissions. The SO_2 program, which covers most EGU in the contiguous United States,[4] sets a permanent cap on the total amount of SO_2 that can be emitted by EGUs at about one-half of the amount of SO_2 these sources emitted in 1980. Using a market-based cap-and-trade mechanism such as the Acid Rain SO_2 program allows flexibility for individual combustion units to select their own methods of compliance. The program requires NO_X emission limitations for certain coal-fired EGUs, with the objective of achieving a 2 million ton reduction from projected NO_X emission levels that would have been emitted in the year 2000 without implementation of title IV.

The Acid Rain program at 40 CFR parts 72 through 78 comprises two phases for SO_2 and NO_X. Phase I applied primarily to the largest coal-fired electric generation sources from 1995 through 1999 for SO_2 and from 1996 through 1999 for NO_X. Phase II for both pollutants began in 2000. For SO_2, it applies to thousands of combustion units generating electricity nationwide; for NO_X it generally applies to affected units nationwide that burned coal during the period between 1990 and 1995. The Acid Rain program has led to the installation of scrubbers on a number of existing coal-fired units, as well as significant fuel switching to lower sulfur coals. Under the NO_X provisions of title IV, most existing coal-fired units were required to install low NO_X burners.

The 1990 CAA also placed much greater emphasis on interstate transport of ozone and its precursors, and on control of NO_X to reduce ozone nonattainment. This led to the formation of several regional NO_X trading programs. In 1998, EPA promulgated regulations, known as the NO_X SIP Call,[5] that required 21 states in the eastern United States and the District of Columbia to reduce NO_X emissions that contributed to nonattainment in downwind States. EPA based the reduction requirements on, and States implemented those requirements through a cap-and-trade approach targeted to EGUs. This program has resulted in the installation of significant amounts of selective catalytic reduction (SCR). The first SCR application in the U.S. on a coal-fired boiler started operating in 1993. At the end of 2002, 56 U.S. boilers were operating with SCR.

By notice dated May 12, 2005 [70 FR 25162], we promulgated the Clean Air Interstate Rule (CAIR) to reduce interstate transport of SO_2 and NO_X emissions. This rule established statewide emission reduction requirements for SO_2 and NO_X for States in the CAIR region. The emission reduction requirements are based on controls that are known to be highly cost effective for EGUs. This program was based on extensive experience in the Acid Rain and NO_X SIP Call cap-and-trade programs for major sources of SO_2 and NO_X.

In the CAIR, we took final action requiring 28 States and the District of Columbia to adopt and submit revisions to their State Implementation Plans (SIPs), under the requirements of CAA section 110(a)(2)(D), that would eliminate specified amounts of SO_2 and/or NO_X emissions. In developing the CAIR, we limited the requirements to those 28 States because we did not find that emissions from other States contribute significantly to downwind $PM_{2.5}$ or 8-hour ozone nonattainment.

Each State covered by CAIR may independently determine which emission sources to control, and which control measures to adopt. Our analysis indicates that emissions reductions from EGUs are highly cost effective, and we encourage States to base their CAIR SIP programs on emissions reductions from EGUs. States that do so may allow their EGUs to participate in an EPA-administered cap-and-trade program as a way to reduce the cost of compliance, and to provide compliance flexibility. The EPA-administered cap-and-trade program includes fossil-fuel fired boilers, combustion turbines, and certain cogeneration units with nameplate capacity of more than 25 MWe producing or supplying electricity for sale as defined in 40 CFR 96.104 and 96.204.[6] Some of these units have never been subject to major NSR because they commenced construction before the effective date of the major NSR regulations, and they have never undertaken modifications. CAIR Units must hold annual allowances. Each allowance authorizes the emission of one ton of NO_X for a specified calendar year. For SO_2 allowances with vintage in the years before 2010, each allowance authorizes the emission of one ton of SO_2 for a calendar year. For 2010 and beyond, each allowance authorizes the emission of less than one ton of SO_2 per year.[7] The CAIR emissions reductions will be implemented in two phases, one beginning in 2009 (2010 for SO_2) and a second beginning in 2015. CAIR Units are subject to stringent monitoring, recordkeeping, and reporting requirements. Owner/operators must monitor and report CAIR Unit emissions using CEMS or other monitoring methodologies that are as precise, reliable, accurate, and timely according to the requirements in 40 CFR part 75. Source information management, emissions data reporting, and allowance trading occur through EPA-administered

[4] The Acid Rain program generally applies to all fossil-fuel fired combustion devices that, if commencing commercial operation before November 15, 1990, serve on or after November 15, 1990 a generator greater than 25 MW producing electricity for sale and that, if commencing commercial operation on or after November 15, 1990, serve on or after November 15, 1990 any generator producing electricity for sale. The Acid Rain program does not apply to a small portion of the national EGU inventory, including some cogeneration units (many of which are natural-gas fired), certain independent power producers, and solid waste incineration units.

[5] See 63 FR 57356, October 27, 1998 (Item 002 in E–Docket OAR–2005–0163).

[6] The proposed test would not apply to all cogeneration units. It would apply only to those EGU that §§ 96.104, 96.204, and 96.304 identify. On August 24, 2005 [70 FR 49708; see item 0029 in E-Docket OAR–2005–0163], we proposed changes to §§ 96.104 and 96.204 to exclude units (serving a greater-than-25 MW generator) that stopped operating before November 15, 1990 and do not resume. In this notice, we also proposed changes to the definition of ''EGU'' to exclude certain solid waste incineration units.

[7] For allowances of vintage years 2010–2014, each allowance authorized the emission of half a ton of SO_2 for a calendar year. For allowances of vintage years 2015 and beyond, each allowance authorizes the emission of 0.35 tons of SO_2 for a calendar year. See item 0019 in E–Docket OAR–2005–0163–70 FR 25258, May 12, 2005. See also 40 CFR 96.202.

online systems. Any source found to have excess emissions must surrender allowances sufficient to offset excess emissions and surrender future allowances equal to three times the excess emissions.[8]

The CAIR will result in significant reductions in SO_2 and NO_X emissions across the region that it covers. CAIR, if implemented through controls on EGUs, would result in EGU emissions reductions in the CAIR States of roughly 73 percent for SO_2 and 61 percent for NO_X from 2003 levels. The rule would affect roughly 3,000 fossil-fuel-fired units. As Table 1 shows, these sources accounted for roughly 89 percent of nationwide SO_2 emissions and 79 percent of nationwide NO_X emissions from EGUs in 2003.[9]

TABLE 1.—EGU SO_2 AND NO_X EMISSIONS IN 2003 AND PERCENTAGE OF EMISSIONS IN THE CAIR AFFECTED REGION (TONS)

	SO_2	NO_X
CAIR region	9,407,406	3,222,636
Nationwide	10,595,069	4,165,026
CAIR emissions as % nationwide	89%	79%

Note: Region includes States covered for the annual SO_2 and NO_X trading programs (Alabama, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin).

We estimate that the CAIR will reduce SO_2 emissions by 3.5 million tons[10] in 2010 and by 3.8 million tons in 2015. We also estimate that it will reduce annual NO_X emissions by 1.2 million tons in 2009 and by 1.5 million tons in 2015. (These numbers are for the 23 States and the District of Columbia that are affected by the annual SO_2 and NO_X requirements of CAIR. There are 28 States affected by CAIR, but only 23 States affected by the CAIR annual SO_2 and NO_X requirements. That is, five States are only affected by the CAIR seasonal NO_X trading program requirements.) If all the affected States choose to achieve these reductions through EGU controls, then EGU SO_2 emissions in the affected States would be capped at 3.6 million tons in 2010 and 2.5 million tons in 2015,[11] and EGU annual NO_X emissions would be capped at 1.5 million tons in 2009 and 1.3 million tons in 2015.

The CAIR will also improve air quality in all areas of the eastern U.S. We estimate that the required SO_2 and NO_X emissions reductions will, by themselves, bring into attainment 52 of the 79 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2010, and 57 of the 74 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2015. We further estimate that the required NO_X emissions reductions will, by themselves, bring into attainment three of the 40 counties that are otherwise projected to be in nonattainment for 8-hour ozone in 2010, and six of the 22 counties that are otherwise projected to be in nonattainment for 8-hour ozone in 2015.[12] In addition, the CAIR will improve $PM_{2.5}$ and 8-hour ozone air quality in the areas that would remain nonattainment for those two NAAQS after implementation of the rule. The CAIR will also reduce $PM_{2.5}$ and 8-hour ozone levels in attainment areas.

To determine the statewide emission caps under the CAIR, we assumed the application of highly cost-effective control measures to EGUs and determined the emissions reductions that would result. Specifically, we modeled emissions reductions using the Integrated Planning Model (IPM) with wet and dry desulfurization (FGD, commonly known as scrubbers) technologies for SO_2 control and SCR technology for NO_X control on coal-fired boilers.[13] These are fully demonstrated and available pollution control technologies. The design and performance levels for these technologies were based on proven industry experience.

We expect many EGUs to install scrubbers and SCR to meet the emissions reductions required under the CAIR. As a result of the CAIR, we project installation of scrubbers on an additional 64 GW of existing coal-fired generation capacity for SO_2 control and SCR on an additional 34 GW of existing coal-fired generation capacity for NO_X control by 2015. By 2020, we expect installation of scrubbers on an additional 82 GW of existing coal-fired generation capacity for SO_2 control and SCR on an additional 33 GW of existing coal-fired generation capacity for NO_X control.[14]

In the western half of the U.S. and other States where CAIR will not apply, the Best Available Retrofit Technology (BART) requirements of the regional haze rule will also apply to EGUs that may not be subject to major NSR. The regional haze rule requires all States to take steps in their implementation plans to improve visibility in Class I areas. [64 FR 35714 (July 1, 1999); 70 FR 39104 (July 6, 2005)] Under the Regional Haze program, States are to address all types of manmade emissions contributing to visibility impairment in Class I areas, including those from mobile sources, stationary sources (such as EGUs), area sources such as residential wood combustion and gas stations, and prescribed fires. CAA sections 169(b)(2)(A) and (g)(7) specifically require installation of BART for emissions of visibility-impairing pollutants (for example, SO_2 and NO_X) from certain existing stationary sources, including large EGUs. The CAA defines

[8] For a complete description of requirements for CAIR Units under the EPA-administered trading program, see item 0019 in E-Docket OAR–2005–0163–70 FR 25162.

[9] See our Regulatory Impact Analysis for the CAIR at 6–9. The RIA is available at *http://www.epa.gov/air/interstateairquality/pdfs/finaltech08.pdf.* See item 0022 in E-Docket OAR–2005–0163.

[10] These data are from EPA's most recent Integrated Planning Model (IPM) modeling reflecting the final CAIR as promulgated at 70 FR 25162. Please see the final CAIR rule at 70 FR 25162. (*See* item 0019 in E-Docket OAR–2005–0163) for a complete description of the assumptions related to these data.

[11] The banking provisions of the cap-and-trade program encourage sources to make significant reductions before 2010. Such early reductions are beneficial because they encourage greater health benefit sooner. However, due to the use of banked allowances, EPA does not project that these caps will be met in 2010 and 2015.

[12] See item 0019 in E-Docket OAR–2005–0163—70 FR 25162.

[13] U.S. EPA, Regulatory Impact Analysis for the CAIR at p. 7–5. See item 0022 in E-Docket OAR–2005–0163. Available at *http://www.epa.gov/air/interstateairquality/pdfs/finaltech08.pdf.* For more information about the highly cost effective controls for EGUs that were used to establish the emissions reductions under the CAIR, see also 69 FR 4612 (item 0003 in E-Docket OAR–2005–0163).

[14] See CAIR RIA at 7–8 and 7–9 (item 0022 in E-Docket OAR–2005–0163). The CAIR RIA is also available at *http://www.epa.gov/air/interstateairquality/technical.html.* In 1999, total electric generating capacity was 781 GW, of which utilities accounted for approximately 85 percent. U.S. EPA NSR 90-Day Review Background Paper, p. 12. See item 0039 in E-Docket OAR–2005–0163.

a BART-eligible source as a stationary source of air pollutants that falls within one of 26 listed categories and that was put into operation between August 7, 1962 and August 7, 1977, with the potential to emit 250 tons per year of any visibility-impairing pollutant. [CAA section 169(b)(2)(A) and (g)(7); 40 CFR 51.301.]

We issued guidelines for implementing BART requirements,[15] including presumptive BART control levels for emissions of SO_2 and NO_X from utility boilers located at power plants over 750 MW. Those presumptive BART control levels are based on cost effective controls. As explained in the guidelines, as a general matter States must require owners and operators of greater than 750 MW power plants to meet these BART emission limits. In addition, while States are not required to follow these guidelines for EGUs located at power plants with a generating capacity of less than 750 MW, based on our analysis, we believe that States will find these same presumptive controls to be highly cost effective, and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW, regardless of the size of the plant at which they are located.

Regional haze is the result of air pollutants emitted by numerous sources over a wide geographic region. As a result, EPA has encouraged States to work together in developing and implementing their air quality plans addressing regional haze. In fact, the States have been working together in regional planning organizations to develop regional plans. Moreover, we have proposed a process by which States may use an emissions trading program in place of facility-by-facility BART requirements. In these aspects, the requirements for BART are similar to those under the CAIR. We expect that both the CAIR and the BART requirements will reduce regional SO_2 and NO_X emissions from EGUs in a cost-effective manner.

We developed three scenarios to project the nationwide EGU SO_2 and NO_X emissions reductions under BART. Under the medium stringency scenario (Scenario 2), we estimate that BART controls will result in annual NO_X reductions of 585,459 tons, about a 9.6 percent reduction; and in annual SO_2 reductions of 390,224 tons, about a 2.3 percent reduction, over the 2015 base case.[16] Under Scenario 2, BART is projected to result in the installation of scrubbers on an additional 6.2 GW of existing coal-fired generation capacity for SO_2 control in 2015 (relative to expected reductions from CAIR alone). For NO_X control, this BART scenario is also projected to result in installation of combustion control equipment on an additional 24 GW of coal-fired generation capacity by 2015, as well as installation of SCR on an additional 2.4 GW on coal-fired generation capacity by 2015.

We have conducted analyses based on emission projections and air quality modeling showing that CAIR (as we expect States to implement it) will achieve greater reasonable progress towards the national visibility goal than would BART for affected EGUs. In our final BART rule (70 FR 39104), we thus promulgated regional haze rule revisions allowing States to treat CAIR as an in-lieu-of BART program for SO_2 and NO_X emissions from EGUs in CAIR-affected States, where those States participate in the EPA-administered cap and trade program. The criteria for making ''better than BART'' determinations have now been codified in the regional haze rule at 40 CFR 51.308(e)(3). We thus expect EGUs in CAIR-affected States to be subject to SIPs implementing CAIR SO_2 and NO_X requirements rather than to BART.

We are aware that there are some EGUs that would not be subject to the Acid Rain program or BART, would not be included in the CAIR program due to their geographic location, and that also would not be subject to major NSR unless they choose to modify.[17] First, there is a set of EGUs that are not in CAIR affected States, and that are BART-eligible but may not be subject to BART. Assuming Scenario 2, there would be approximately 28 coal-fired EGUs that are BART-eligible, not in the CAIR region, and have a capacity less than 200 MW. Smaller units such as these generally are not base load units. The total capacity for these 28 units is approximately 4 GW, less than one half of a percent of current national capacity. Of these 28 units, approximately 3 GW have NO_X controls and approximately 2 GW have SO_2 controls. There are approximately 47 oil or gas-fired EGUs that are BART-eligible, not in the CAIR region, and have a capacity less than 200 MW. The total capacity for these 47 units is approximately 5 GW, also less than one half of a percent of national capacity. Of these 47 units, approximately 1 GW have NO_X controls. Of these 47 units, 41 are gas-fired. Gas-fired EGU are clean burning and generally emit very small amounts of SO_2. The main control strategy for SO_2 emissions from oil-fired units is using lower-sulfur fuel.

The second set of EGUs that may not be subject to any control requirements are those in the non-CAIR States that are not subject to major NSR and are not BART-eligible. Some EGUs that are located in non-CAIR States and that began operation on or before August 7, 1962 would not be BART-eligible. These units would neither be subject to BART nor included in regulations implementing the CAIR program. They would also not be subject to major NSR unless they choose to modify. Some may be subject to the Acid Rain program. Our database[18] shows that there is a total of about 2 GW of coal capacity (less than one half of a percent of national capacity) outside the CAIR region that was constructed or began operations before 1962. This capacity represents about 25 units at about 13 plants, ranging in capacity from 38–135 MW. Smaller, older units such as these generally are not base load units. We estimate that these units have a potential to emit SO_2 and NO_X that is high enough that they would have been subject to major NSR if they had been constructed later. Of these 25 units, four have NO_X controls and six have SO_2 controls. The 13 plants are geographically dispersed.

Thus, as we explain above, there are a small number of EGUs that may not be required to control emissions under any program, but they comprise a very small portion of the national capacity and will have a minimal impact on emissions.[19] As we note in Table 1,

[15] See **Federal Register** 70 FR 39104 (July 6, 2005) at item 0017 in E-Docket OAR–2005–0163.

[16] That is, these are the reductions that are estimated to occur under Scenario 2 in addition to the reductions that are estimated to occur under CAIR. See BART RIA at 3–6—item 0004 in E-Docket OAR–2005–0163. Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. EPA–452/R–05–004. U.S. Environmental Protection Agency, June 2005. Also, available at: *http://www.epa.gov/oar/visibility/actions.html.*

[17] Major stationary sources of regulated NSR pollutants that commenced construction on or after August 7, 1977 are subject to requirements under major NSR, including meeting emissions limitations based on BACT or LAER. To be BART-eligible, an EGU must have commenced operation between August 7, 1962 and August 7, 1977. Thus, due to their construction date, BART-eligible EGUs are not subject to major NSR unless they modify.

[18] Information received from Mikhail Adamantiades, U.S. EPA, Clear Air Markets Division on October 4, 2005—item 0051 in E-Docket OAR–2005–0163.

[19] We expect all State agencies to include EGUs in their regulations implementing the CAIR rule. We therefore believe that in CAIR-affected States, regulations implementing the CAIR will apply to all EGU. However, there is a possibility that a State agency would decide not to include EGU in their SIP regulations implementing the CAIR. We believe this possibility to be remote.

approximately 90 percent of nationwide EGU SO_2 emissions and approximately 80 percent of nationwide EGU NO_X emissions are from EGU in the CAIR affected region. Furthermore, we note that EGUs, including EGUs outside the CAIR region, are subject to national caps on SO_2 emissions through the Acid Rain program requirements. We therefore believe that any EGUs that might remain uncontrolled would have a negligible impact on national emissions of regulated NSR pollutants.

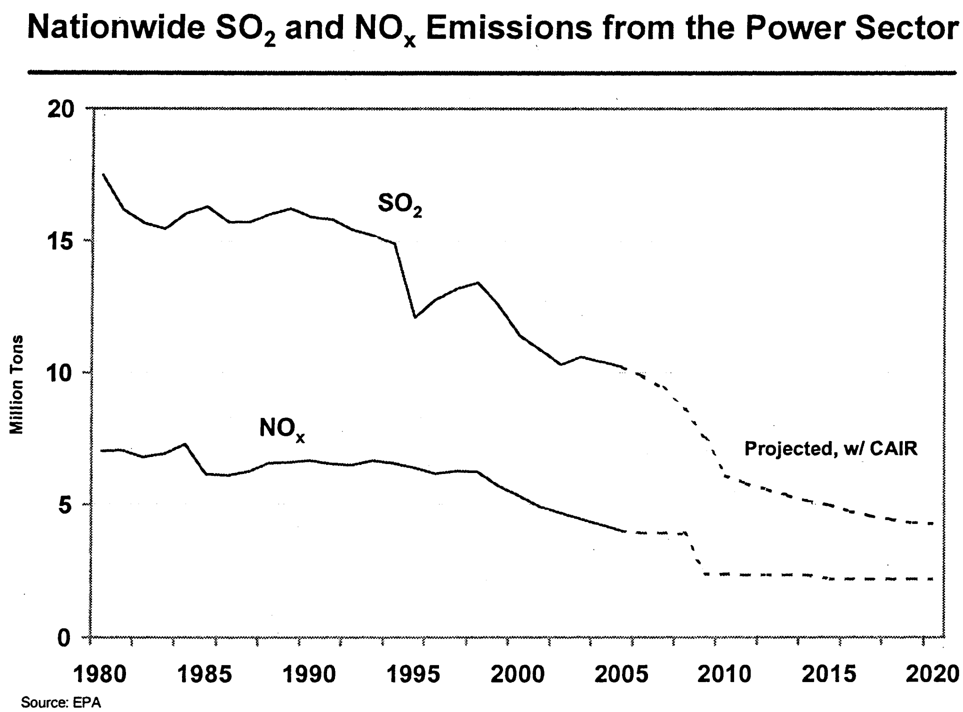
Finally, as Table 2 below shows, substantial reductions in SO_2 and NO_X emissions are projected to occur following the imposition of these market-based strategies after 1990.

TABLE 2.—REDUCTION IN EGU NATIONAL ANNUAL EMISSIONS [20]

[In thousands of tons per year]

	1990	2015	Emission reduction	Percent reduction
SO_2 (Annual)	15,700	4,770	10,930	70
NO_X (Annual)	6,700	1,916	4,784	71

The figure below shows the national reductions in EGU SO_2 and NO_X emissions that have occurred to date, and that we expect to occur, due to these programs.



In addition, we expect further reductions from implementation of BART.

These reductions in national emissions for the utility sector are especially significant considering that national capacity continues to increase. In 1990, national nameplate capacity for EGUs was 692,935 MW, in 2002 it was 758,756 MW, and in 2015 we anticipate it to be 776,377 MW.[21]

In summary, since the 1990 CAA Amendments, additional requirements for EGUs have applied under the Acid Rain program and the NO_X SIP Call, and we expect significant additional reductions as States implement the CAIR. These regional and national programs apply or will apply to EGUs, regardless of when the EGUs were constructed or began operating. More importantly, these national or regional trading programs set permanent caps on SO_2 and NO_X emissions. Notably, the CAIR will permanently cap SO_2 and NO_X emissions in the CAIR region, which covers approximately 80 percent of national electric generating capacity. We expect all of the SO_2 and NO_X reductions under CAIR to come from EGUs. Despite growth in the utility and other sectors, these programs have substantially reduced SO_2 and NO_X emissions and even more substantial reductions will occur as a result of the CAIR. The BART program will further reduce national EGU SO_2 and NO_X emissions.

[20] Modeled 1990 baseline emissions from John Robbins. Reductions based on 2015 projected emissions for EGUs greater than 25 MW, assuming BART Scenario 2 (medium stringency scenario). These projected reductions assume control requirements implemented under CAIR, the Acid Rain program, BART (Scenario 2), and State rules. Under BART Scenario, our IPM modeling assumes control of all EGU at least 200 MW, regardless of the size of the plant at which the EGU is located. See BART RIA at 7–7—item 0004 in E-Docket OAR–2005–0163.

[21] Data from EPA Office of Air and Radiation, Clean Air Markets Division. See item 0012 in E-Docket OAR–2005–0163.

The Acid Rain, NO_X SIP Call and CAIR programs will require substantial reductions in SO_2 and NO_X emissions over the next decade. At the same time, they provide substantial flexibility to EGUs in responding to these regulatory requirements, allowing EGUs to make cost effective control decisions. As a result, they serve a function similar to that under major NSR of balancing environmental goals and encouraging economic growth.

As we discuss in more detail in Section V.B. of this preamble, the primary purpose of the major NSR program is not to reduce emissions, but to balance the need for environmental protection and economic growth. That is, the goal of major NSR is to minimize emissions increases from new source growth. The major NSR approach we have been taking leads to outcomes that have not advanced the central policy of the major NSR program as applied to existing sources. This is because the program is not designed to cut back on emissions from existing major stationary sources through limitations on their productive capacity, but rather to ensure that they will install state-of-the-art pollution controls at a juncture where it otherwise makes sense to do so. We also do not believe the outcomes produced by the approach we have been taking have significant environmental benefits compared with the approach we are proposing today. We do not believe that today's revised emissions test is substantially different from the actual-to-projected-actual test. This is particularly true in light of the substantial EGU emissions reductions that other programs have achieved or are expected to achieve. We therefore believe that, to any extent today's revised emissions test would lead to more growth in emissions than the actual-to-projected-actual test would, the emissions increases from that growth would be substantially less than the emissions reductions we expect from the Acid Rain, NO_X SIP Call, CAIR, and BART programs.[22]

C. Requirements for Pollutants Other Than SO_2 and NO_X

Concerning PM and lead, the application of the major NSR program to EGU emissions increases would be unlikely to result in the implementation of any additional controls. Current BACT and LAER limits to control PM (both PM_{10} and $PM_{2.5}$) for EGUs are achieved through the application of baghouses or electrostatic precipitators (ESPs) to individual boilers. Of the 450 coal-fired plants, the following controls are in place to reduce PM emissions from EGU: 79 plants have bag houses (fabric filters), 354 plants have ESPs, and 21 plants have both ESPs and baghouses.[23] Therefore, virtually all coal-fired EGUs are already well-controlled for PM. The minimal lead emissions from EGUs are in particulate form, and are captured by PM controls.

For CO and VOC, the only BACT/LAER requirements that exist for boilers are ''good combustion'' practices. EGUs operate under enormous economic incentives not to waste fuel, and good combustion practices conserve fuel. Thus, EGUs have strong incentives to use good combustion practices, regardless of the major NSR regulations. We believe that virtually all EGUs are already implementing such practices to control CO and VOC. Accordingly, we do not believe that VOC or CO emissions increases at EGU are likely or that the application of the major NSR program to changes made at the EGUs would be likely to result in the implementation of additional controls for CO and VOC. Furthermore, even if EGU did not have built-in incentives to control VOC and CO emissions, we do not believe that today's revised emissions test would result in emissions increases compared to the actual-to-projected-actual test. Therefore, we expect no air quality impacts due to CO or VOC emissions as a result of this proposed rule.

IV. Today's Proposed Rule

Today, we are proposing to allow existing EGUs to use the same maximum achievable hourly emissions test we apply under NSPS to determine whether a physical change in or change in the method of operation (physical or operation change) results in an emissions increase under the major NSR program. We request public comments on all aspects of the proposed changes.

This section also provides a brief background on the emissions increase test used in the NSPS and major NSR programs, and summarizes our proposed changes to the NSR program, which is necessary to understand the proposed regulations. For a fuller discussion on the statutory and legislative background of the major NSR program, please see Section V.B. of today's preamble.

A. Background on Existing Regulations

Both the NSPS and major NSR programs impose requirements on modifications of stationary sources. Our NSPS regulations contain a two-part definition of modification. The first part substantially mirrors the statutory text found in section 111(a)(4) of the Act, while the second elaborates upon the first. In simplistic terms, the Act establishes a two-step test for determining whether an activity is a modification. First you must determine whether the activity qualifies as a physical change or operational change of a stationary source, then you must determine whether that activity also increases the amount of pollution emitted by the stationary source.

You can find the regulatory text defining ''modification'' within the NSPS general provision regulations at 40 CFR sections 60.2 and 60.14. Substantially mirroring CAA 111(a)(4), § 60.2 contains a general description of the two components an activity must satisfy to qualify as a modification. Section 60.14 elaborates on the general description contained in § 60.2 by more precisely defining how you measure the amount of pollution that results from an activity, and listing activities that do not qualify as physical or operational changes.[24]

Unlike our NSPS regulations, our major NSR regulations do not contain a specific definition of the term ''modification.'' Instead, our regulations define ''major modification,'' which adds provisions for determining whether an activity satisfies the second component (whether there is an increase in the amount of an air pollutant). Specifically, the major modification definition provides a two-step procedure for measuring emissions increases. Under this process, a source looks at whether a project will result in a significant emissions increase on an annual basis and then whether contemporaneous increases and decreases will result in a significant net emissions increase (netting) on an annual basis.

The differences between the definition of ''modification'' as applied in the NSPS program and ''major modification'' as applied in the major NSR program illustrate some fundamental differences in the way we have implemented the programs to date.

[22] In our projections of emissions changes under the Acid Rain program, the NO_X SIP Call, the CAIR, and BART, increases in future electric generating capacity are accounted for.

[23] See information received from Kevin Culligan, U.S. EPA Clean Air Markets Division, item 0044 in E-Docket OAR–2005–0163.

[24] We described the relationship between the provisions contained in sections 60.2 and 60.14 in a 1974 **Federal Register** notice in which we stated that the regulations concerning modifications in § 60.14 clarify the phrase ''increases the amount of any air pollutant'' that appears in the definition of modification in § 60.2. 39 FR 36946, October 15, 1974—see item 0014 in E-Docket OAR–2005–0163.

First, the NSPS program regulates all emissions increases (that is, it regulates any increase in the hourly emissions), while the major NSR program exempts emissions increases that are less than significant (that is, it exempts emissions increases that are less than 40 tpy). Second, the NSPS program regulates modifications of ''affected facilities,'' which are typically small collections of equipment within a larger manufacturing plant. The major NSR program regulates modifications of major stationary sources. Accordingly, all the equipment within a larger manufacturing plant is looked at collectively. Finally, because the NSPS regulates small collections of equipment rather than the entire plant, increases in one part of the plant cannot be ''offset'' with decreases at other parts of the plant. [See *Asarco, Inc.* v. *EPA*, 578 F.2d 319 (D.C. Cir. 1978).] Conversely, major NSR regulates changes in emissions at the major stationary source as a whole and allows decreases in emissions from one part of the plant to ''offset'' increases in emissions that occur in another part of the plant. [See *Alabama Power* v. *Costle*, 636 F.2d 323 (D.C. Cir. 1979).] This process is known as ''netting.''

The NSPS modification provisions apply an hourly emission rate test to measure emissions increases resulting from a physical or operational change. Specifically, under the regulations, whether there is an emissions increase is determined by comparing the pre-change baseline hourly emission rate to the post-change hourly emission rate. For electric utility steam generating units (EUSGUs), the baseline hourly rate is ''the maximum hourly emissions achievable at that unit during the 5 years prior to the change.'' [See 40 CFR 60.14(h).] EPA has described this rate as the rate, in the past 5 years, that the source could achieve at its physical and operational capacity (57 FR 32330). Thus, this hourly rate represents the highest rate at which the source could actually emit during the relevant period.

The baseline hourly emissions rate for non-EGUs is likewise based on current maximum capacity, which is defined as the production rate at which the source could operate without making a capital expenditure. [See § 60.14(e)(2).] As provided in § 60.14 (b)(1), we measure the emissions rate in kg/hr or lbs/hr. Therefore, the baseline hourly emissions for non-utilities is also based on the highest rate at which the source could actually emit. As we stated at 57 FR 32316 referring to the rules for non-utilities, ''under current NSPS regulations, emissions increases, for applicability purposes, are calculated by comparing the hourly emission rate, at maximum physical capacity, before and after the physical or operational change. That is, to determine whether a change to an existing facility will increase the emissions rate, the existing NSPS regulations authorize the use of an ''emissions factor analysis'', or materials balance, continuous monitoring, or manual emissions test to evaluate emissions before and after the change.''

This characterization of the emissions rate as based on the highest rate at which the source could actually emit is consistent with our previous statements and regulations. In the preamble to the December 23, 1971 NSPS rules, we stated that ''procedures have been modified so that the equipment will have to be operated at maximum expected production rate, rather than rated capacity, during compliance tests.'' (See 36 FR 24876.) The December 1971 rules specified that a change in the method of operation did not include ''an increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility.'' (See 36 FR 24877.) On October 15, 1974, we proposed to change this provision to ''an increase in the production rate of an existing facility, if that increase can be accomplished without a major capital expenditure'' and to move it to § 60.14(e)(2).[25] [*See* 39 FR 36946.] In describing the reason for this change, we specifically stated that hourly emissions must be determined considering what the source could actually emit, rather than ''design'' (nameplate) capacity.

> The exemption of increases in production rate is no longer dependent upon the ''operating design capacity.'' This term is not easily defined and for certain industries the ''design capacity'' bears little relationship to the actual operating capacity of the facility.

Id. at 39 FR 36948.

As Congress indicated in the legislative history for the 1977 CAA,[26] design capacity is equivalent to potential to emit. In the NSPS regulations, neither the EGU nor the non-EGU hourly emissions are based on design capacity. Thus, to describe the NSPS test as a potential-to-potential test is inaccurate, and EPA has not asserted that the NSPS test is a potential-to-potential test. Instead, the Agency has at times referred to ''hourly potential emissions.'' Where we have referred to hourly potential emissions, we have also been clear that we are referring to what the source is actually able to emit at current maximum capacity. For example, in the 1988 WEPCO memorandum, we stated:

> Pursuant to longstanding EPA interpretations, the emission rate before and after a physical or operational change is evaluated at each unit by comparing the hourly potential emissions under current maximum capacity to emissions at maximum capacity after the change.''[27]

Our current major NSR regulations measure an emissions increase at an existing emissions unit using the ''actual-to-projected-actual'' applicability test. Under this approach, we compare an emissions unit's ''baseline actual emissions'' to the emission unit's projected actual emissions after the change. Our current test distinguishes how non-EUSGUs compute an emissions unit's baseline actual emissions from the method used for EUSGUs. We define baseline actual emissions for non-EUSGUs as the average annual emission rate calculated from any consecutive 24-month period in the past 10 years. For EUSGUs, the baseline actual emissions equals the average annual emission rate achieved over any consecutive 24-month period in the past 5 years unless there is another period of time that is more representative of normal source

[25] These changes were adopted on December 16, 1975 (see 40 FR 58416) and the provisions have remained unchanged, except to clarify that they apply to the facility rather than to the stationary source containing that facility.

[26] The legislative history is clear that Congress considered ''potential to emit'' and ''design capacity'' to be equivalent terms. The House bill defined a major stationary source as any stationary source of air pollutant which directly emits or has the design capacity to emit 100 tons annually of any pollutant for which an ambient air quality standard is promulgated. [H.R. Report 95–564, p. 172 (1977), U.S. Code Cong. & Admin.News 1977, p. 1552.] The House bill also stated that ''major emitting facilities proposing to construct facilities must receive State permits. All sources with the design capacity to emit 100 tons per year or more of any pollutant must receive a permit.'' [H.R. Report 95–564, p. 149 (1977), U.S. Code Cong. & Admin.News 1977, p. 1529.] The Senate amendment defined major emitting facility as any stationary source with an annual potential to emit 100 tons or more of any pollutant. The Senate bill also required permits for major stationary sources with potential to emit over 250 tons per year. The conference committee agreed on the provisions on major emitting facilities and major stationary sources to be included in the statute at 302(j) and 169(1) as follows.

The State plan must require permits for: (a) All 28 categories listed in the Senate bill if the sources has the potential (design capacity) to emit over 100 tons per year; and (b) any other source with the design capacity to emit more than 250 tons per year of any air pollutant. [H.R. Report 95–564, p. 149 (1977), U.S. Code Cong. & Admin.News 1977, p. 1153].

[27] Memorandum dated September 9, 1988, from Don R. Clay, Acting Assistant Administrator for Air & Radiation, U.S. EPA, to David A. Kee, Director, Air and Radiation Division, U.S. EPA Region V. *Applicability of PSD and NSPS Requirements to the WEPCO Port Washington Life Extension Project.* Available at: *http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/wpco2.pdf.* Page 9 and item 0005 in E-Docket OAR–2005–0163.

operations. We use the same definition of projected actual emissions for both EUSGUs and non-EUSGUs. The rules generally define projected actual emissions as the maximum annual rate of emissions at which the emissions unit is projected to operate for the first 5 years after the emissions unit begins operation following the change. See 40 CFR 51.166 (b)(47) and (b)(40) to understand all aspects of the baseline actual emissions and projected actual emissions definitions.

B. What We Are Proposing

1. Test for EGUs Based on Maximum Achievable Hourly Emissions

Today, we are proposing to allow existing EGUs to use the same maximum achievable hourly emissions test applied in the NSPS to determine whether a physical or operation change results in an emissions increase under the major NSR program. Accordingly, the major NSR regulations would apply at an EGU if a physical or operational change results in any increase in the maximum hourly emissions rate. We are not proposing to allow EGUs to exclude emissions increases that fall below a particular significant emissions rate, or to allow EGUs to use plantwide netting to avoid NSR applicability.

We are proposing to define EGUs in the same way that this term is defined by the CAIR and Acid Rain regulations. Specifically, we would define EGU as fossil-fuel fired boilers and turbines serving an electric generator with a nameplate capacity greater than 25 megawatts (MW) producing electricity for sale.[28] Fossil fuel is described as natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material. The term ''fossil fuel-fired'' with regard to an emissions unit means combusting fossil fuel, alone or in combination with any amount of other fuel or material.

This definition of EGU is broader than the definition of EUSGU currently found in the NSPS and NSR regulations. The EGU definition includes cogeneration facilities and simple cycle gas turbines that would not qualify under EUSGU definitions. That is, the revised emissions test would apply to EUSGUs, cogeneration facilities, and simple cycle gas turbines.

[28] On August 25, 2005, we proposed regulatory language to clarify that the definition of EGU in CAIR does not include municipal waste combustors or solid waste incinerators, and to clarify that the definition only covers entities that have at any time since November 15, 1990 served an electric generator with a nameplate capacity greater than 25 megawatts (MW) producing electricity for sale. See 70 FR 49708, item 0029 in E-Docket OAR–2005–0163.

To incorporate the NSPS maximum achievable hourly emissions test into the major NSR regulations, we are proposing to add a definition of modification to the major NSR regulation that will apply to changes affecting regulated NSR pollutant emissions in lieu of the current definition of major modification. We would add the new definition to all versions of the NSR regulations including 40 CFR 51.165, 51.166, 52.21, 52.24, and in Appendix S of 40 CFR part 51, as well as any regulations we finalize to implement major NSR in Indian Country.[29]

We propose that this definition would substantially mirror, but would not be identical to, the definition of modification contained in section 60.14 of the NSPS regulations. There are differences between the two programs that prevent a wholesale adoption of the NSPS modification definition into the major NSR provisions. For example, the NSPS program applies the definition of modifications only to stationary sources and pollutants for which a particular NSPS standard applies. Specifically, the NSPS program regulates modifications of ''affected facilities,'' which are typically small collections of equipment within a larger manufacturing plant. The NSPS program also specifies which pollutants from the affected facility are regulated. For example, Subpart Da of 40 CFR part 60 regulates emissions increases of sulfur dioxides, nitrogen oxides, and particulate matter from EUSGUs. The major NSR program, on the other hand, regulates modifications of major stationary sources. Accordingly, all the equipment within a larger manufacturing plant is looked at collectively. Furthermore, the Act mandates that major NSR requirements apply to modifications at any major stationary source that increases emissions of any regulated NSR pollutant.[30] The proposed definition is as follows.

''Modification,'' for an electric generation unit (EGU), means any physical change in, or change in the method of operation of, an EGU which increases the amount of any regulated NSR pollutant emitted into the atmosphere by that source or which results in the emission of any regulated NSR pollutant(s) into the atmosphere that the source did not previously emit. An increase in the amount of regulated NSR pollutants must be determined according to the provisions in paragraph (x) of this section.

[29] In the near future, we plan to publish a proposed rule addressing NSR requirements in tribal lands.

[30] The major NSR regulations define NSR regulated pollutants at 40 CFR 51.166(b)(49).

We disagree with the Fourth Circuit's holding in *Duke Energy*, and thus believe we are able to make reasonable distinctions between the NSPS and NSR programs where appropriate. Although the Fourth Circuit held in *Duke Energy* that we must use the same definition of modification in both the NSPS and NSR programs where appropriate, it only discussed this finding in the context of the component term of the definition ''increases in the amount of any air pollutant emitted.'' In fact, the Court noted that the Fourth Circuit had previously held that the term ''stationary source,'' a component term within the definition of ''modification,'' could be interpreted differently in the NSPS and PSD programs because Congress had not defined the term in both programs. [*Duke Energy*, slip op. at 17, citing *Potomac Elec. Power Co.* v. *EPA*, 650 F.2d 509, 518 (4th Cir. 1981).[31] Accordingly, we believe it is reasonable to interpret the *Duke Energy* decision as requiring, within the Fourth Circuit, that the maximum hourly emissions test be used within the major NSR provisions, but as not requiring the identical treatment of the term ''physical change in or change in the method of operation.'' Based on our interpretation, we propose to incorporate the part of the major modification definition that addresses regulation of physical and operational changes into the modification definition for EGUs. We request comment on this interpretation.

We also are not proposing to change our current methodologies for computing the amount or availability of emissions offsets, or for computing emissions for purposes of conducting an ambient impact analysis. Accordingly, EGUs will be required to follow the existing regulations related to these provisions.

In proposing this NSR test for EGUs based on maximum achievable hourly emissions, we are aware of the recent opinion by the United States Court of Appeals for the District of Columbia Circuit in *New York* v. *EPA*, 413 F.3d 3 (D.C. Cir. June 24, 2005). In that case, the Court rejected challenges to substantial portions of EPA's 2002 NSR rules. However, the Court did hold that EPA lacked authority to promulgate the ''Clean Unit'' provision of the 2002 rules, and in doing so, held that ''the plain language of the CAA indicates that

[31] The *Duke Energy* Court also noted that in *Northern Plains Res. Council* v. *EPA*, 645 F.2d 1349, 1356 (9th Cir. 1981) [see item 0046 in E-Docket OAR–2005–0163], the Ninth Circuit allowed EPA to interpret the statutory term ''commenced'' differently in the NSPS and PSD regulations. *Duke Energy*, slip op. at 17.

Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.'' *Id.*, slip op. at 40.

We respectfully disagree with the Court's holding that the plain language of the CAA requires that NSR apply to changes in actual emissions, and the United States has filed a petition for rehearing and rehearing *en banc* as to this holding. We believe that the CAA is silent on whether increases in emissions for purposes of determining whether a physical or operational change constitutes a modification must be measured in terms of actual emissions, potential emissions, or some other currency. Therefore, we believe that even if the test for emissions increases that we propose today were based on something other than actual emissions, it would be an appropriate interpretation and entitled to deference under step 2 of the analytical process set forth in *Chevron U.S.A., Inc.* v. *Natural Res. Def. Council*, 467 U.S. 837 (1984). Nonetheless, we recognize that we must promulgate a rule that is consistent with the D.C. Circuit's resolution of this issue.

Regardless of whether our petition for rehearing in *New York* v. *EPA* is denied, we believe that a test based on maximum achievable hourly emissions is a test based on actual emissions. The maximum achievable hourly emissions test measures what a source has been actually able to emit based on physical and operating capacity during a representative period prior to the change. For most, if not all EGUs, the hourly rate at which the unit is actually able to emit is substantively equivalent to that unit's historical maximum hourly emissions. States require most, if not all EGUs, to perform periodic performance tests under applicable SIPs and enhanced monitoring requirements. The NSPS regulations require a source to conduct testing based on representative performance of the affected facility, generally interpreted as performance at current maximum physical and operational capacity. [40 CFR 60.8(c).] [32] Also, in the National Stack Test Guidance that we issued on September 30, 2005, we recommended that facilities conduct performance tests under conditions that are ''most likely to challenge the emissions control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition.'' [33] Most EGUs actually emit at the highest level at which they are capable of emitting at some time within a 5-year baseline period.

We solicit comment on our assumption that an NSR test for EGUs based on maximum achievable hourly emissions is, in fact, a test that would be based on a measure of actual emissions in light of the manner in which EGUs are operated.

As we noted earlier, the current major NSR regulations contain a definition of major modification. Specifically, the major modification definition provides a two-step procedure for measuring emissions increases. Under this process, a source looks at whether a project will result in a significant emissions increase on an annual basis and then whether contemporaneous increases and decreases will result in a significant net emissions increase (netting) on an annual basis. We are proposing to replace this definition of major modification with a definition of modification based on the maximum hourly achievable emissions increase test (or one of the two other emissions increase tests that we discuss in the following sections, maximum achieved emissions or an output-based measure of emissions). However, we request comment on whether we should instead add the definition of modification based on an hourly emissions test, which would then be followed by the current major modification provisions based on annual emissions. Specifically, we request comment on whether the major NSR program should include a four-step process as follows: (1) Physical change or change in the method of operation; (2) maximum achievable hourly emissions increase (or another alternative emissions increase test such as discussed below); (3) significant emissions increase as in the current major NSR regulations; (4) significant net emissions increase as in the current major NSR regulations.

2. Test for EGUs Based on Maximum Achieved Hourly Emissions

We are also proposing in the alternative a slightly different emissions test from the maximum achievable hourly emissions test applied in the NSPS program. Specifically, we are requesting comment on whether we should promulgate an emissions test based on assessing an emissions unit's historical maximum hourly emissions. That is, instead of calculating what a source could actually emit at current maximum capacity, actual emissions would be determined by a specific measure of historical emissions, such as with CEMS. This test may be preferred by some because the method of assessing the source's actual emissions is similar to the current major NSR approach for determining baseline actual emissions.

We would call this test the maximum achieved hourly emissions test. Under this approach, an EGU would determine whether an emissions increase will occur by comparing the pre-change maximum actual hourly emission rate to a projection of the post-change maximum actual hourly emission rate. The pre-change maximum actual hourly emission rate would be the highest rate at which the EGU actually emitted the pollutant within the 5-year period immediately before the physical or operational change.

Like the maximum achievable hourly emissions test, the maximum achieved emissions test is a measure of a source's actual emissions. The maximum achieved hourly emissions test is based on a specific measure of historical actual emissions during a representative period. Therefore, even if our petition for rehearing in *New York* v. *EPA* is denied, we believe that a test based on maximum achieved hourly emissions satisfies the requirement that major NSR applicability be based on ''some measure of actual emissions.''

We request comment on whether adopting this alternative approach would achieve all of the policy objectives supporting this proposal as effectively as the maximum achievable hourly emissions test would. We stated that two of our goals for this proposal are to streamline the regulatory requirements applying to EGUs by allowing EGUs to apply the same test for measuring emissions increases from modifications under both the NSPS program and NSR program, and to provide some nationwide consistency in the emissions calculation procedures in light of the Fourth Circuit's decision in *Duke*. We believe that the maximum achievable hourly emissions test could better comport with our policy goals than the maximum achieved hourly emissions test. Therefore, given that we do not believe that there is substantive difference in the baseline emissions between the two tests, we prefer adoption of the maximum achievable hourly emissions test as used in the NSPS program.

[32] See also 36 FR 24876, December 23, 1971. Referring to performance tests, we stated that ''Procedures have been modified so that the equipment will have to be operated at maximum expected production rate, rather than rated capacity, during compliance tests.

[33] See the EPA memorandum, *Issuance of Final Clean Air Act National Stack Testing Guidance,* from Michael M. Stahl, Director, Office of Compliance, to Regional Compliance/Enforcement Division Directors, September 30, 2005, p. 14. Available at *http://www.epa.gov/Compliance/resources/policies/monitoring/caa/stacktesting.pdf* and item 0007 in E–Docket OAR–2005–0163.

In view of our policy goal to establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs, we also request comment on extending the maximum achieved hourly emissions test to emissions increases in the NSPS program. Specifically, we request comment on whether we should revise 40 CFR 60.14 to include a maximum achieved hourly emissions test, either in lieu of the maximum achievable hourly emissions test or in addition to the maximum achievable hourly emissions test. We intend to provide more detailed information concerning the maximum achieved hourly emissions test in the NSPS program in our supplemental proposal.

3. Emissions Test Based on Energy Output

We also request comment on adopting an NSR emissions test based on mass of emissions per unit of energy output, such as lb/MW hour or nanograms per Joule. Applicability under the major NSR program has historically been based on annual limits measured in tons per year. As we discuss in Section V. of this preamble, Congress did not specify how to calculate ''increases'' in emissions and left EPA with the task of filling that gap. We believe establishing an NSR emissions increase test based on mass emissions per unit of energy output would be a reasonable use of our discretion.

We also believe that incorporating an output-based emissions test has merit for several reasons. The primary benefit of output-based standards is that they recognize energy efficiency as a form of pollution prevention. Using more efficient technologies reduces fossil fuel use and also reduces the environmental impacts associated with the production and use of fossil fuels. Another benefit is that output-based standards allow sources to use energy efficiency as a part of their emissions control strategy. Energy efficiency as an additional compliance option can lead to reduced compliance costs, as well as lower emissions. We want to encourage use of efficient units that displace less efficient, more polluting units. This approach is especially desirable where EGUs are already subject to market-based systems such as the Acid Rain program, NO_X SIP Call, and State trading programs implementing the CAIR, as those programs increase incentives for using efficient units.

Furthermore, an output-based emissions test would comport with recent State efforts. Several States have initiated regulations or permits-by-rule for distributed generation (DG) units, including combustion turbines. States that have made efforts to regulate DG sources include California, Texas, New York, New Jersey, Connecticut, Delaware, Maine, and Massachusetts. Those State rules include emission limits that are output-based, and many allow generators that use combined heat and power (CHP) to take credit for heat recovered. For example, Texas recently passed a DG permit-by-rule regulation that gives facilities 100 percent credit for steam generation thermal output, and incorporates HRSG and duct burners under the same limit. The California Air Resources Board (CARB) also has output-based emission limits, which allow DG units using CHP to take a credit to meet the standards, at a rate of 1 MW-hr for each 3.4 million British thermal units (MMBtu) of heat recovered, or essentially, 100 percent. The draft rules for New York and Delaware also allow DG sources using CHP to receive credit toward compliance with the emission standards.

We request comment on the desirability and feasibility of using an output-based test for measuring emissions increases in the major NSR program. In view of our policy goal to establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs, we also request comment on extending an output-based test for measuring emissions increases to the NSPS program. Specifically, we request comment on whether we should revise 40 CFR 60.14 to include an output-based emissions test, either in lieu of the maximum achievable and maximum achieved hourly emissions tests or in addition to these emissions tests. We intend to provide more detailed information concerning the output-based emissions test for both the NSR and NSPS programs in our supplemental proposal.

C. Pollutants to Which the Revised Applicability Test Applies

We request comments on our proposal that the revised emissions test (either our preferred maximum achievable test, the alternative maximum achieved test, or the output-based emissions test) should apply to all regulated NSR pollutants. In light of our policy goal to provide a nationally consistent program and to streamline major NSR for EGUs, we believe it is desirable to provide the alternative test for emissions increases of all regulated NSR pollutants. As described in detail in Section III of this preamble, we do not believe that today's revised emissions test is substantially different from the actual-to-projected-actual test, particularly in light of the substantial SO_2 and NO_X emissions reductions that other programs have achieved or are expected to achieve from EGUs. As we describe in further detail in Section III.C. of this preamble, the application of the major NSR program to EGU emissions increases of regulated NSR pollutants other than SO_2 and NO_X would be unlikely to result in the implementation of any additional controls.

D. Significant Emissions Rates

As we stated, we are not proposing to allow EGUs to exclude emissions increases that fall below a particular significant emissions rate. Our current major NSR regulations allow sources to avoid major NSR applicability if the physical or operational change results in an emissions increase that is below a significant level.

We codified the existing significant rates based on a *de minimis* legal theory that balances the administrative burden of running the program with the environmental benefit of undergoing major NSR review. In codifying the significant rates, we relied on our belief that Congress did not intend to regulate every physical or operational change at a major source. Because a maximum achievable hourly emissions rate test is based on computing a unit's rate of emissions in kg/hr, whereas the existing significant rates are expressed in tons per year (tpy), it is more administratively efficient to eliminate the need to compute significant emission rates from the proposed emissions test.

By eliminating the use of a significant emission rate threshold for modifications, we balance the differences in these tests, and focus permitting authority resources on reviewing all changes that result in increases in existing capacity.[34] We believe that this result is consistent with our interpretation of Congressional intent in that it assures that, at a minimum, increases in existing capacity undergo major NSR review. See a fuller discussion of the legislative history in Section V. of this preamble.

We request comment on our conclusion that the maximum achievable hourly emissions test should regulate all emissions increases and not

[34] To the extent that sources prefer to avoid major NSR by taking enforceable limitations on their potential to emit, reviewing authority resources will also be focused on establishing synthetic minor limits subject to the conditions in § 51.165(a)(5)(ii), § 51.166(r)(2), and § 52.21(r)(4). That is, sources basically have two choices—enforceable limitations on emissions increases or major NSR review for changes that result in increases in existing capacity.

just those that are above the significant rate. We also request comment on the alternative of including a significant emissions rate as a component of the maximum achievable hourly emissions test for major NSR. If we include use of the significant rate within the emissions increase test, sources would have to extrapolate their maximum hourly emission rate to a maximum annual emission rate. We request comment on an appropriate approach for making this extrapolation.

E. Eliminating Netting

Netting has played an important role over the history of the major NSR program by, to some extent, allowing sources to manage plantwide changes in a way that assures that the major stationary source's emissions do not increase. Nonetheless, numerous stakeholders, including individuals among State, environmental, and industry groups, believe that our netting procedures in the existing program are too complicated. State and environmental groups also believe netting allows construction of brand new emissions units to occur without requiring emissions controls. These stakeholders suggested removing the netting provisions or revising the procedures to shorten the contemporaneous period to allow for ''project netting.'' Project netting allows the emissions increases and decreases from a given project to be summed together without the need to review all changes over the previous 5 years.

Because the maximum achievable hourly emissions test is based on increases in kg/hr, including netting within the emissions test would further complicate administration of the program by adding additional calculations to an already complicated process. Accordingly, eliminating the ability to net pollutant increases and decreases would simplify applicability determinations and assure that increases in existing capacity could not occur without preconstruction review and installation of appropriate controls (except where sources otherwise establish enforceable limitations to avoid emissions increases) . Also, one of the advantages of our proposal to eliminate netting is that there would be no unreviewed increases.

Nevertheless, the Court in *Alabama Power* held that the Act requires EPA to allow netting within our regulations (the ''bubble'' approach), because such an approach is consistent with the purposes of the Act. The Court reasoned that Congress intended to ''generate technological improvement in pollution control, but this approach focused upon 'rapid adoption of improvements in technology as new sources are built,' not as old ones [plants] were changed without pollution increases.''

It is important to place this ruling in the context of the rules before the Court at that time. Our 1978 regulations required a source-wide accumulation of emissions increases without providing for an ability to offset these accumulated increases with any source-wide decreases. In finding that we must apply a bubble approach, the Court held that we could not require sources to accumulate increases without also accumulating decreases. It is unclear whether the Court would have reached the same conclusion if the emissions test before the Court only considered the increases from the project under review and not source-wide increases from multiple projects. Moreover, contrary to the *Alabama Power* Court's analysis, some have argued that the netting approach may have impeded Congress' objective of promoting ''rapid adoption of improvements in technology as new sources are built.'' This is because it allows construction of new units at existing facilities without emissions controls, while requiring major NSR for large greenfield sources.

We request comment on our observations related to the *Alabama Power* Court's decision related to netting and whether a major NSR program without netting can be supported under the Act. Specifically, we request comment on whether, in adding the maximum achievable emissions test for EGUs within the major NSR program, we should retain the requirement to compute a net emissions increase. Under this approach, a source would first determine whether an activity results in an increase in maximum hourly emissions, and then the source would determine whether this increase, when considered with other increases and decreases at the major stationary source over the past 5 years, would result in a net emissions increase at the major stationary source. We also request comment on whether we should retain netting, but shorten the contemporaneous period to the time of construction and allow EGUs to use only ''project'' netting in computing whether a physical or operational change results in an emissions increase.

F. Benefits of Maximum Achievable Hourly Emissions Test

We believe that implementing our proposed maximum achievable hourly emissions rate test for EGUs offers significant benefits over the current actual-to-projected-actual emissions test. The proposed regulations (and our alternate proposal) would provide nationwide consistency in how States implement the major NSR program for EGUs. They would also establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs. However, we are also requesting comment on whether the proposed maximum achievable hourly emissions test (and our alternate proposals) should be limited to the geographic area covered by CAIR, or to the geographic area covered by both CAIR and BART.

Furthermore, the proposed regulations allow owner/operators to make changes that, without increasing existing capacity, promote the safety, reliability, and efficiency of EGUs. We do not want to discourage plant owners or operators from engaging in activities that are important to restoring, maintaining, and improving plant safety, reliability, and efficiency. Uncertainties inherent in the current major NSR permitting approach can exacerbate the reluctance to engage in these activities. To elaborate on the uncertainty issues: Unless an owner or operator seeks an applicability determination from his or her reviewing authority, it can be difficult for the owner or operator to know with reasonable certainty whether a particular activity would trigger major NSR. This gives the owner or operator five choices, two of which the owner or operator is not likely to select, and the other three of which have significant drawbacks for the productivity of the plant.

First, the owner or operator may simply seek an NSR permit. That course, however, is likely to be time-consuming and expensive, since it will likely result in a requirement to retrofit an existing plant with state-of-the-art pollution controls, which often is very costly and can present significant technical challenges. Therefore, an owner or operator is not likely to select this option if it can be avoided.

Second, the owner or operator may proceed at risk without a reviewing authority determination. That option, however, is also not likely to be attractive where a significant replacement activity is involved, because if the owner or operator proceeds without a reviewing authority determination and if we later find that he or she made an incorrect determination on their own, the owner or operator faces potentially serious enforcement consequences. Those consequences could well include substantial fines and penalties for violation of the CAA (along with the further consequences of violation of the CAA) and a requirement to install state-of-the-art pollution controls, even though those controls present technical issues or represent a significant enough expenditure that they likely would have deterred the owner or operator from seeking a permit in the first place. The owner or operator is not likely to take this risk if he or she believes there is a high probability of these kinds of consequences and if he or she has other options.

Third, the owner or operator may seek an applicability determination. That process, too, is time-consuming and expensive, albeit typically less so than seeking a permit. Furthermore, there is a possibility that EPA could eventually make a different applicability determination than the State has made, which can add more time and uncertainty to the process. This path presents a potentially significant barrier to EGUs and other industries. This approach also is likely to delay important projects that would enhance the safety, reliability, and efficiency of the plant while the owner/operator waits for the applicability determination.

Fourth, the owner or operator may forego or curtail activities that would enhance the safe, reliable, or efficient operation of its plant, instead opting to repair existing components, even though they are inferior to current-day components because they probably are less advanced and less efficient than current technology. Foregoing the activities altogether will reduce plant safety, reliability and efficiency; curtailing or postponing them does as well, differing only in the degree of these effects.

Finally, the owner or operator may curtail the plant's productive capacity by replacing components with less than the best technology to be more certain that the replacement is within the regulatory bounds. Or he or she may agree to limit the source's hours of operation or capacity or install air pollution controls that are less than state-of-the-art. These alternative courses of action, however, will also result in loss of plant productivity.

The current approach to major NSR is also problematic for State and local reviewing authorities. They require the regulatory authorities to devote scarce resources to make complex determinations, including applicability determinations, and consult with other agencies to ensure that any determinations are consistent with determinations made for similar circumstances in other jurisdictions and/or that other reviewing authorities would concur with the conclusion. In our June 2002 report to the President, we concluded that the current major NSR program has impeded or resulted in the cancellation of projects that would have maintained and improved the reliability, efficiency, or safety of existing energy capacity.

We believe it is desirable to change the approach to major NSR. The current approach discourages sources from replacing components, and encourages them to replace components with inferior components or to artificially constrain production in other ways. This behavior does not advance the central policy goals of the major NSR program as applied to existing sources. The central policy goal is not to limit productive capacity of major stationary sources, but rather to ensure that they will install state-of-the-art pollution controls at a juncture where it otherwise makes sense to do so. We also do not believe the outcomes produced by the approach we have been taking have significant environmental benefits compared with the approach we are proposing today.

We believe that these problems would be significantly reduced by the rule we are proposing today. Our new approach would provide more certainty both to source owners or operators who will be able better to plan activities at their facilities, and to reviewing authorities who will be able better to focus resources on other areas of their environmental programs rather than on time-consuming determinations. The effect should be to remove disincentives to undertaking activities that improve efficiency, safety, reliability, and environmental performance.

We also note that today's proposed emissions test would simplify applicability determinations for sources by using the same test for both the NSPS and NSR programs. Moreover, it eliminates the burden of projecting future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, because any increase in the emissions under the maximum achievable emissions test would logically be attributed to the change. It reduces recordkeeping and reporting burdens on sources because compliance will no longer rely on synthesizing emissions data into rolling average emissions. It improves compliance by making the rules more understandable, which correspondingly reduces the reviewing authorities' compliance and enforcement burden.

Nonetheless, despite identifying many of these benefits in our analysis of the Settlement Agreement that EPA had entered into in *Chemical Manufacturer's Association* v. *EPA*, No. 79–112, we rejected the use of that approach because we stated that such an approach was not acceptable for major NSR applicability as a general matter.[35] We based our conclusions on concerns that the Settlement Agreement Approach would allow facilities to generate paper credits for netting and offsets because the facility may never have operated at its full potential emissions. Moreover, we raised concerns that unreviewed increases could lead to increment violations.

Today's proposal differs from the Settlement Agreement Approach in an important way. We retain the existing procedures for calculating offset credits to avoid any possibility of generating paper reductions. Moreover, we requested comment on eliminating or limiting the availability of netting. Either approach would alleviate the possibility of generating paper reductions. One of the advantages of our proposal to eliminate netting is that there would be no unreviewed increases. (That is, all emission increases, including those less than 40 tpy, would be reviewed.) On the other hand, if we continue to include netting provisions in the major NSR applicability test, those provisions will continue to be based on actual emissions.

Importantly, States' implementation of the Acid Rain, CAIR, and BART programs will generate significant reductions in pollution and thereby decrease the likelihood that an unreviewed source could cause an increment violation. We conducted modeling to estimate the impact of the CAIR program on nationwide emissions trends and ambient concentrations. The modeling shows that emissions are predicted to decline in all parts of the country. With nationwide emissions declining, there is a decreased likelihood that unpermitted emissions increases could violate a PSD increment by returning a given geographical area to levels above that area's historical actual levels. We also conducted modeling to estimate the impact of the BART rule on nationwide emissions trends and visibility. The BART modeling shows that emissions will decline beyond those reductions under CAIR, particularly in Class I areas.[36]

[35] We discuss the regulatory history related to the CMA Exhibit B Settlement Agreement in Section V. of today's preamble. *See* also 67 FR 80205, December 31, 2002—item 0030 in E-Docket OAR–2005–0163.

[36] For a complete discussion of the emissions reductions and air quality impacts of the BART rule, see Chapter 3 of the RIA for the BART final rule, available at *http://www.epa.gov/oar/visibility/actions.html* and item 0004 in E-Docket OAR–2005–0163.

Furthermore, our analyses estimate improvements in air quality related values from both the CAIR and BART.[37]

The emissions reductions from the programs that affect electric utilities principally come from cap-and-trade programs such as the Acid Rain Program, the NO_X SIP Call, and the CAIR. Concerns have been expressed at times about how trading programs might have a disparate impact on some populations, especially those located closest to some of the affected emission sources. EPA is developing a methodology to look at the local impacts of these types of programs and will attempt to quantify the impacts on local communities for the final rule.

For all the reasons we articulate in this section, we now believe that it is appropriate to consider the benefits of implementing the maximum achievable hourly emissions increase test.

G. Would States Be Required To Adopt the Revised Emissions Test?

Consistent with our longstanding practice, we are proposing that the revised emissions test would be a core, mandatory, minimum program element for SIPs implementing the part C and part D major NSR programs. We are also proposing that State and local agencies would submit NSR SIP revisions incorporating the revised emissions test within 12 months after promulgation of the final rules. For the reasons we articulate in Section V.C. of this preamble, we believe the maximum achievable hourly emissions test implements Congressional intent for the major NSR program and in a more effective manner for EGUs than the current major NSR program.

Consistent with our longstanding practice, we are also proposing that if a State were to decide it does not want to implement the revised emissions test, that State would need to make a showing that its program is not less stringent than our program.

V. Statutory and Regulatory History and Legal Rationale

This section provides our legal basis and rationale for the proposed changes. In support of our legal basis and rationale, this section provides a more detailed background than that in Section IV. on the emissions increase test used in the NSPS program and major NSR program.

A. The NSPS Program

In the 1970 CAA Amendments, Congress included, for the first time, emission standards for new sources of air pollution, termed ''new source performance standards'' (NSPS). [CAA section 111.] The purpose of the NSPS program was to prevent new air pollution problems by requiring that new sources of emissions, including those from expanded or modified existing facilities, be designed and equipped to incorporate demonstrated emissions controls.[38]

Specifically, Congress required the EPA to set emission limitations for categories of new stationary sources of air pollution based on the best system of emissions reduction, considering costs, that has been adequately demonstrated. Congress also specifically required that the NSPS apply to modifications of existing facilities, and defined ''modification'' in CAA section 111(a)(4) as follows:

> ''The term modification means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' [39]

The statute does not specify how increases in emissions are to be determined and the 1970 legislative history does not directly speak to it. Nonetheless, the legislative history shows that, at a minimum, Congress was concerned about regulating new sources of emissions caused by expanded or modified capacity, as the following two statements indicate:

> Therefore, particular attention must be given to new stationary sources which are known to be either particularly large-scale polluters or where the pollutants are extra hazardous. The legislation, therefore, grants authority to the Secretary of Health, Education, and Welfare to establish emission standards for any such sources which either in the form of entire new facilities or in the form of expanded or modified facilities, or because of expanded or modified operation or capacity, constitute new sources of substantially increased pollution.[40]
>
> Therefore, it would appear to me that, for instance, an old steel plant which altered its production of a particular unit or operation, even though that unit was an old unit, would be controlled just as its competitor, a new steel plant, would be controlled, where new equipment plus new sources of emissions occur? That is correct.[41]

On December 23, 1971 (36 FR 24877), we promulgated the first NSPS regulations. Consistent with Congressional intent to regulate new sources of emissions, these regulations included a definition of modification applying to affected facilities as follows.

> Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which a standard applies) emitted by such facility or which results in the emission of any air pollutant (to which a standard applies) not previously emitted, * * *

Id.

On December 16, 1975, we revised the definition of modification in the NSPS program. 40 FR 58416. Our revisions clarified how to measure emissions increases when there is a physical change or change in the method of operation at an existing facility. Specifically, we added the phrase ''emitted into the atmosphere'' to the definition of modification at 40 CFR 60.2 and added new provisions to define how to measure emissions increases for purposes of determining whether a modification occurs, at 40 CFR 60.14.[42]

Our focus in adding the regulatory phrase ''emission rate to the atmosphere'' was to regulate facilities only when they constitute a new source of emissions. We do not believe that Congress intended to draw existing facilities into NSPS applicability when there was no increase in the amount of pollution that a facility could actually emit to the environment, either because the new equipment did not emit

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[37] For our discussion of these impacts related to the CAIR, see the CAIR RIA at 5–1, item 0022 in E-Docket OAR–2005–0163. The CAIR RIA is also available at *http://www.epa.gov/air/interstateairquality/technical.html*. For our discussion of these impacts related to the BART, see the BART RIA at 5–1, available at *http://www.epa.gov/oar/visibility/actions.html* and item 0004 in E-Docket OAR–2005–0163.

[38] See House Report 91–1146 at 5365: The purpose of this authority is to prevent the occurrence of significant new air pollution problems arising from or associated with such new sources. As explained above, such new sources may take the form either of entirely new facilities or expanded or modified facilities, or of expanded or modified operations which result in substantially increased pollution. * * * The emission standards shall provide that sources of such emissions shall be designed and equipped to prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility as determined by the Secretary.

[39] CAA section 111(a)(4). This section has not been amended since it was inserted into the statute in 1970.

[40] H.R. Rep 91–1146, p. 5361 (1970).

[41] Congressional Record—HR 17090, June 10, 1970 at 19212.

[42] This language concerning modifications was never included in the NSR regulations at §§ 51.165, 51.166, 52.21, 52.24, and Appendix S to part 51. On January 23, 1980 (see 45 FR 5616, item 32 in E-Docket OAR–2005–0163), we amended this language to delete the portions of § 60.14 that implemented the bubble concept, which the United States Court of Appeals for the District of Columbia Circuit rejected in a decision rendered January 27, 1978. [*Asarco, Inc.* v. *EPA,* 578 F.2d 319 (D.C. Cir. 1978)—item 0047 in E-Docket OAR–2005–0163.] Following the Asarco decision, § 60.14 was amended to include the current provisions.

pollutants or because the addition of control devices means that the total emissions rate to the atmosphere did not increase. In the proposed preamble, we described the addition of the regulatory term emitted into the atmosphere'' by reference to ''actual emissions,'' measured as post-control emissions at capacity instead of potential emissions without controls.

The proposed amended definition of ''modification'' also includes a new phrase ''emitted into the atmosphere.'' The new phrase clarifies that for an existing facility to undergo a modification there must be an increase in actual emissions. If any increase in emissions that would result from a physical or operational change to an existing facility can be offset by improving an existing control system or installing a new control system for that facility, such a change would not be considered a modification because there would be no increase in emissions to the atmosphere. The Administrator considered defining ''modification'' so that increases in pre controlled (potential) emissions would be considered modifications. However, the proposed definition of modification is limited to increases in actual emissions in keeping with the intent of section 111 of controlling facilities only when they constitute a new source of emissions * * * Section 60.14(b) provides four mechanisms which the Administrator may use (but to which he is not limited) in determining whether an increase in emissions has occurred * * * [T]hese techniques utilize parameters such as maximum production rate * * *''

39 FR 36946, 36946–7.

As we stated in the preamble for the proposal, we added the regulations in § 60.14 to clarify the phrase ''increases the amount of any air pollutant'' in the definition of modification in § 60.2 . [See 39 FR 36946.] We did not create a new definition of modification in codifying § 60.14, but instead used § 60.14 to define how to determine an actual emissions increase based on the facility's maximum hourly emissions rate considering controls. Under § 60.14(b), we calculate an emissions increase by comparing the hourly emissions rate before and after the physical or operational change using ''parameters such as maximum production rate * * *'' 39 FR 36946, 36947. We clarified in the proposed rule that maximum production rate should not be interpreted to mean the facility's operating design capacity (sometimes referred to as name plate capacity) because this rate ''bears little relationship to the actual operating capacity of the facility.'' *Id.* at 36948. Instead, the maximum production rate refers to ''that production rate that can be accomplished without making major capital expenditures.'' *Id.*

Thus, the final regulations calculate changes in what a source is actually able to emit at its capacity, considering controls. (We may refer to this test as the actually-able-to-emit test.) Under § 60.14(b), we calculate an emissions increase by comparing the hourly emissions rate before and after the physical or operational change using ''parameters such as maximum production rate * * *'' 39 FR 36946, 36947. Some refer to this test as a ''maximum hourly potential-to-potential'' emissions test. However, since the NSPS test is based on actual operating capacity rather than design capacity, we believe that this potential-to-potential terminology can be misleading, and prefer the name ''maximum achievable hourly emission rate'' which is similar to the provision we promulgated in the 1992 WEPCO rule, described below. As we discuss in detail in Section IV.A of this preamble, NSPS applicability based on maximum achievable hourly emissions before and after a change was reiterated in various policy memoranda and applicability determinations over the history of the program.

On July 21, 1992, we further revised the NSPS regulations to clarify how we calculate emissions increases at electric utilities. [See 57 FR 32314 (final rule); 56 FR 27630 (June 14, 1991) (proposed rule).] Among other things, this regulation further defined ''capacity'' for electric utilities subject to the NSPS program. Specifically, we indicated that utilities could use the highest hourly emissions rate achievable by the facility at any time during the 5 years before the change.

In this rulemaking, prompted by litigation involving the Wisconsin Electric Power Company and commonly called the WEPCO rule, we noted that the pre-existing NSPS program ''examines maximum hourly emission rates, expressed in kilograms per hour,'' that is, ''[e]missions increases for NSPS purposes are determined by changes in the hourly emissions rates at maximum physical capacity.'' 57 FR 32316. We explained how to determine an hourly rate, as follows.

An hourly emissions rate may be determined by a stack test or calculated from the product of the instantaneous emissions rate, *i.e.*, the amount of pollution emitted by a source, after control, per unit of fuel combusted or material processed (such as pounds of sulfur dioxide emitted per ton of coal burned) times the production rate (such as tons of coal burned per hour) * * *

Id., n. 5.[43]

One of the purposes of the WEPCO rule was to address problems that resulted from the pre-existing method of calculating the maximum hourly emissions rate for NSPS purposes. We stated the following.

Under current regulations, the emissions rate before and after a physical or operational change is evaluated at each unit by comparing the current hourly potential emissions at maximum operating capacity to hourly emissions at maximum capacity after the change. In this calculation, the reviewing authority disregards the unit's maximum design capacity. The original design capacity of a unit, to the extent it differs from actual maximum capacity at the time that the baseline is established due to physical deterioration of the facility, is immaterial to this calculation.

57 FR 32330. We stated that current regulations presented the problem of ''undue emphasis on the physical condition of the affected facility immediately prior to the change * * * For instance, if a unit has broken down and is in need of repairs, the utility's baseline will be artificially low.'' *Id.*

Accordingly, we revised the baseline requirement for electric utilities to include the following constraint.

No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

40 CFR 60.14(h). In characterizing this requirement as a ''modest'' change from the pre-existing regulation, we described this requirement as a

More flexible provision [that] enables units to establish a baseline that is representative of its physical and operational capacity in recent years, while still precluding the use of a baseline tied to original design capacity, which * * * may bear no relationship to the facility's capacity in recent years.

57 FR 32330. Therefore, the WEPCO rule makes clear that the NSPS applicability test for EGUs is the same test (that is, the actually-able-to-emit

[43] By comparison, we added, ''NSR regulations examine total emissions to the atmosphere,'' that is, ''emissions increases under NSR are determined by changes in annual emissions as expressed in tons per year (tpy).'' *Id.* We explained how to determine the annual emissions as follows:

Annual emissions may be calculated as the product of the hourly emissions rate times the utilization rate, expressed as hours of operation per year, or as the product of an emission factor * * * in units of mass emitted per unit of process throughput times the annual throughput * * *

Thus, we said, both NSPS and NSR calculations include the hourly emission rate, but the difference between the two is that the NSR calculation then adds the annual utilization rate, expressed as hours of operation per year.

test) that is generally applicable. Thus, the only difference in the NSPS applicability test for EGUs and non-EGUs is the method for determining the actual operating capacity; for EGUs it is the actual operating capacity at any time in the previous 5 years and for non-EGUs it is actual operating capacity that is achievable without a capital expenditure.

B. The Major NSR Program

EPA promulgated the first set of PSD regulations in 1974 (39 FR 42510), and the first nonattainment major NSR programs in 1976 (41 FR 55524). At that time, the Act did not contain specific provisions for these programs. Instead, the PSD program evolved from a lawsuit claiming that the Act required EPA to ensure that air quality did not deteriorate in areas where air quality met the NAAQS. *Sierra Club* v. *Ruckelshaus,* 344 F.Supp. 253 (D.D.C 1972). We issued the first nonattainment NSR regulations (known as the Emission Offset Interpretative ruling) because attainment dates had passed and we received questions as to whether, and to what extent, new stationary sources could locate in areas that failed to meet the attainment date.

Our preamble to the 1974 PSD rules explained that we intended the PSD definition of ''modified source'' to be consistent with the definition of that term under the NSPS regulations. 39 FR 42510, 42513. Accordingly, the 1974 PSD regulations defined ''modification'' in essentially the same way for both programs. [See 40 CFR 52.01(d); 39 FR 42514; 1975.] Similar to the NSPS provisions, EPA also included an exclusion for increases in production rate and hours of operation within the regulatory definition of physical change in or change in the method of operation.

Congress expressly added an expanded preconstruction permitting program for new and modified major stationary sources to the CAA in 1977. The 1977 Amendments contained different preconstruction permitting requirements for major stationary sources in attainment and nonattainment areas. In areas meeting the NAAQS (''attainment'' areas) or for which there is insufficient information to determine whether they meet the NAAQS (''unclassifiable'' areas), Congress added requirements for the PSD program in part C of title I of the Act. Congress required States to amend their implementation plans to include requirements to prevent the significant deterioration of air quality where such air quality is presently cleaner than existing ambient air quality standards. The main focus of the PSD program was a ceiling on incremental pollution growth. The statute at sections 163(b) and 165(d) included specific ''increments,'' or maximum allowable increases in particulates and sulfur dioxide. In section 166, the 1977 Amendments also required EPA to propose regulations for increments or other means for preventing significant deterioration that would result from the other criteria pollutants. To ensure protection of increments and other means of preventing significant deterioration, Congress established a preconstruction permitting program for major sources that required installation of BACT for major sources. Thus Congress established the PSD program to allow for economic growth in attainment areas, to be accomplished primarily through preservation of increment. The PSD program is implemented primarily through SIP-approved State preconstruction permitting programs meeting the requirements of our regulations at 40 CFR 51.166. Where we have not approved a SIP for an attainment or unclassifiable area, the program is implemented by us or by the States according to the requirements in 40 CFR 52.21.

Congress in 1977 was likewise concerned with permitting new or modified facilities in nonattainment areas. The House proposed a new CAA section 117 for nonattainment areas ''as a means of assuring realization of the dual goals of attainment air quality standards and providing for new economic growth.'' [H.R. Report 95–294, p. 19 (1977), U.S. Code Cong. & Admin. News 1977, p. 1091.] Thus, Congress added the preconstruction permitting program for major stationary sources in nonattainment areas in part D of title I of the 1977 CAA at section 173. The basic requirements of the program as Congress established them in CAA section 173 are still in place: (1) Each major stationary source must go through preconstruction review; (2) the total allowable emissions from new and modified sources must be offset;[44] (3) the source must comply with the lowest achievable emission rate (LAER); (4) there must be a demonstration that all major stationary sources in the State that have the same owner or operator are in compliance; and (5) an alternative sites analysis must be conducted. The preconstruction permitting program for major stationary sources in nonattainment areas, commonly known as the nonattainment major NSR program, is generally implemented through the SIP according to our regulations at 40 CFR 51.165. In transition periods before SIP approval, permits must be issued meeting the conditions of 40 CFR Appendix S, which reflects substantially the same requirements as those in § 51.165.

Following the enactment of the major NSR program in the 1977 CAA, in 1978 we promulgated comprehensive changes to the PSD and nonattainment major NSR regulations to carry out the statutory changes. 43 FR 26380. In the absence of statutory language on how to determine an emissions increase, we initially defined emissions increases in terms of allowable or potential emissions.[45] As with the NSPS regulations, we defined potential emissions as uncontrolled emissions. Nonetheless, when we interpreted 111(a)(4) for the major NSR program, we concluded that the NSPS and NSR program have different purposes. We believed that the NSPS-based definitions and interpretations should not be controlling for NSR purposes. Accordingly, in our 1978 final rules, we defined ''modification'' for NSR differently than we defined it in the NSPS program by including a plantwide approach for reviewing emissions increases (netting), even though the Court held this approach unlawful as applied in the NSPS program. [*Asarco, Inc.* v. *EPA*, 578 F.2d 319 (D.C. Cir. 1978).]

Numerous aspects of our 1978 final rules were challenged by industry, State and environmental petitioners. In June 1979, the D.C. Circuit Court issued a per curiam (preliminary) opinion. [*Alabama Power Co.* v. *Costle*, 606 F.2d 1068 (D.C. Cir. 1979).] In response to that opinion, we immediately undertook to revise our regulations consistent with that opinion and proposed significant changes to the method for determining whether a change constitutes a major modification. Under the proposal, a major

[44] Before 1990, Congress provided States with two options for managing the impact of economic growth on emissions. A State could either provide a case-by-case review of each new or modified major source and require such source to obtain offsetting emissions, or the State could implement a waiver provision which allowed the State to develop an alternative to the case-by-case emissions offset requirement. This alternative program became known as the ''growth allowance'' approach. In 1990, Congress invalidated some of the existing growth allowances and shifted the emphasis for managing growth from using growth allowances to using the case-by-case offset approach.

[45] See the first nonattainment area regulations at Appendix S to part 51, December 21, 1976, at 41 FR 55528/1—see item 0034 in E-Docket OAR–2005–0163. Similarly, a ''major modification'' shall include a modification to any structure, building, facility, installation or operation (or combination thereof) which increases the allowable emission rate by the amounts set forth above. *See* also our 1978 regulations at 43 FR 26380 item 0035 in E-Docket OAR–2005–0163.

modification would occur if a source increased its potential to emit a pollutant.

On December 14, 1979, the Court in *Alabama Power* issued an opinion that superseded its *per curiam* decision. [*Alabama Power* v. *Costle*, 636 F.2d 323 (D.C. Cir. 1979).] [46] EPA interpreted the Court's opinion as focusing on ''actual emissions'' rather than ''potential to emit.'' [45 FR 52676, 52700.] This led EPA to amend its NSR regulations and to change the baseline for measuring emissions increases from using a source's potential to emit to using the source's ''actual emissions.'' The final rules generally defined pre-change actual emissions based on historical emissions (the average of annual emissions for the 2 years preceding the change), but also included provisions to allow source-specific allowables or potential to emit to be a measure of pre-change actual emissions in certain circumstances. [See 40 CFR 52.21(b)(21).]

Our 1980 regulations resulted in numerous challenges, including challenges to our methodology for calculating emissions increases. These challenges were consolidated in *Chemical Manufacturer's Association* v. *EPA,* No. 79–112. EPA entered into a Settlement Agreement which required us to propose an NSPS-like, hourly-potential-to-hourly-potential emissions increase test for modifications (''CMA Exhibit B'').

In 1992, before implementing the Settlement Agreement, we promulgated revisions to our applicability regulations creating special rules for physical and operational changes at EUSGUs. [See 57 FR 32314 (July 21, 1992).] [47] In this rule, as noted above, commonly referred to as the ''WEPCO rule,'' we adopted an actual-to-future-actual methodology for all changes at EUSGUs except the construction of a new electric generating unit or the replacement of an existing emissions unit. Under this methodology, the actual annual emissions before the change are compared with the projected actual emissions after the change to determine if a physical or operational change would result in a significant increase in emissions. To ensure that the projection is valid, the rule requires the utility to track its emissions for the next 5 years and provide to the reviewing authority information demonstrating that the physical or operational change did not result in an emissions increase.

In promulgating the WEPCO rule, we also adopted a presumption that utilities may use as baseline emissions the actual annual emissions from any 2 consecutive years within the 5 years immediately preceding the change.

On July 23, 1996, we proposed CMA Exhibit B as one alternative as part of a comprehensive proposal to reform the NSR regulations. [61 FR 38250.] Finally, on December 21, 2002, we took final action on certain elements of our 1996 proposal and declined to promulgate the CMA Exhibit B approach. Instead, we revised the emissions calculation procedures to include an actual-to-projected-actual emissions test for all sources. [67 FR 80290.]

While industry, environmental groups and States filed petitions for review with the United States Court of Appeals for the District of Columbia Circuit regarding both our 1980 and 1992 rules, those challenges were not heard and decided until earlier this year when those challenges were consolidated with challenges to our 2002 revisions to the major source NSR program. [See *New York* v. *EPA,* No. 02–1387 (D.C. Cir. June 24, 2005).] The Court upheld EPA's regulations concerning the actual-to-projected-actual test. *Id.,* slip op. at 26. While industry argued that the statute requires EPA to use the same definition of ''modification'' for the NSPS program and NSR programs, the Court concluded that industry had waived the argument and thus declined to address this issue in its ruling.[48]

In a separate part of its opinion, the Court held that EPA had discretion in defining the period of time over which to calculate emissions, for purposes of ascertaining whether a physical or operational change increases those emissions. *Id.* at 39–40. The Court upheld EPA regulations that revised that period as a 2-year period within the 10 years prior the change. The Court stated:

> In enacting the NSR program, Congress did not specify how to calculate ''increases'' in emissions, leaving EPA to fill in that gap while balancing the economic and environmental goals of the statute [citation omitted]. Based on its experience with the NSR program and its examination of the relevant data, EPA determined that a ten-year lookback period would alleviate the problems experienced under the 1980 rule and advance the economic and environmental goals of the CAA * * * [W]e defer to EPA's statutory interpretation under Chevron step 2 * * *.

Id. at 39–40.

In another part of the Court's opinion, the Court held that the NSR modification requirement, which incorporates by reference CAA section 111(a)(4), ''unambiguously defines 'increases' in terms of actual emissions.'' *Id.* at 62. EPA has filed a petition for rehearing in which we argue that this holding was in error, and that the term ''increases'' is ambiguous for NSR purposes and therefore EPA has discretion to promulgate an actuals, allowables, or potentials interpretation.

On June 15, 2005, the United States Court of Appeals for the Fourth Circuit handed down a decision concerning an enforcement action against Duke Energy Corporation concerning major NSR applicability at eight electric utilities. [*United States* v. *Duke Energy Corp.,* No. 04–1763.] The Court ruled that ''because Congress mandated that the PSD definition of 'modification' be identical to the NSPS definition of 'modification,' the EPA cannot interpret ''modification'' under the PSD inconsistently with the way it interprets that term under the NSPS.'' *Id.,* slip op. at 12–14). The Court also stated that ''No one disputes that prior to enactment of the PSD statute, the EPA promulgated NSPS regulations that define the term ''modification'' so that only a project that increases a plant's hourly rate of emissions constitutes a 'modification' '' *Id.,* slip op. at 18. The Court thus held that for purposes of the PSD program, emissions increases must be determined by comparing the pre- and post-change maximum hourly emissions.

C. Legal Rationale

1. Maximum Achievable Hourly Emissions Test

Sections 169(2)(C) and 171(4) of the Act specify that the definition of ''modification'' set forth in CAA section 111(a)(4) applies in the PSD and nonattainment major NSR programs. Pursuant to CAA section 111(a)(4), the term modification means ''any physical change or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' The statute, however, does not prescribe the methodology for determining when an emissions increase has occurred following a physical change or change in the method of operation. *New York* v. *EPA,* slip op. at 31, 39–40, No. 02–1387

[46] The Court amended the December 14th opinion on April 21, 1980. See item 0024 in E-Docket OAR–2005–0163.

[47] The regulations define ''electric utility steam generating units'' as any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts (MW) of electrical output to any utility power distribution system for sale. See, for example, § 51.166(b)(30).

[48] The Court expressed a view that Congress' failure to expressly incorporate the NSPS regulatory definition of NSPS argues against a finding that Congress intended the NSPS definition to apply in implementing the NSR program. *Id.* at 25.

(D.C. Cir. June 24, 2005). Since Congress did not specify how to calculate ''increases'' in emissions, it left EPA with the task of filling that gap while balancing the economic and environmental goals of the CAA. *Id.* at 39–40.

When a statute is silent or ambiguous with respect to specific issues, the relevant inquiry for a reviewing court is whether the Agency's interpretation of the statutory provision is permissible. *Chevron U.S.A., Inc.* v. *NRDC, Inc.*, 467 U.S. 837, 865 (1984). Accordingly, EPA has the discretion to propose a reasonable method by which to calculate emissions increases for purposes of NSR applicability. Although we do not assert that the NSPS interpretation is the only one we can adopt for NSR purposes (we followed quite a different interpretation from 1980 until today), at the very least we believe that the statutory silence on this issue delineates a zone of discretion within which EPA may operate.

As we discuss in the previous section of this preamble, we modeled our early major NSR method for calculating any emissions increases after the existing NSPS program. In the NSPS program, we define major modification as the maximum achievable hourly increase in emissions at actual operating capacity, considering controls. That is, we defined actual emissions as post-controlled emissions at current capacity. Our early NSR regulations defined emissions increases in terms of allowable or potential emissions, consistent with our interpretation that Congress intended the modification definition to apply to expansions in capacity, but not to apply to the use of existing capacity.

As we previously explained, we promulgated the actual-to-potential emissions test [49] in 1980, after interpreting the *Alabama Power* final decision as shifting the focus from regulating increases in existing capacity to regulating possible changes in actual emissions. Our decision to change to a historical actual emissions baseline must be viewed in light of the progress of air quality programs at that time. The air quality was significantly degraded in a number of areas and air emission trends showed a steady decline in the quality of our nation's air in some jurisdictions. State and local air pollution control programs were just developing, and the programs mandated in 1990 by parts 2, 3, and 4 of title I of the Act and programs such as the Acid Rain program, the NO_X SIP Call, CAIR, and BART did not exist. Accordingly, the major NSR program provided States one of the few opportunities under the Clean Air Act to mitigate rising levels of air pollution through regulation of potential emissions increases from existing sources. Moving to an actual-to-potential applicability test was a sensible approach for managing air quality at that time, and interpreting the *Alabama Power* final decision to support this goal was appropriate.

The *Alabama Power* Court recognized EPA's discretion to define the same statutory terms differently in the NSR and NSPS regulations. [*Alabama Power Co.* v. *Costle*, 636 F.2d at 397–98 (EPA has latitude to adopt definitions of the component terms of ''source'' that are different in scope from those that may be employed for NSPS and PSD, due to differences in the purpose and structure of the two programs).] Moreover, while the Court held that potential to emit must be determined considering controls, and that NSR major modifications must be determined considering total or net emissions from the source over a contemporaneous period, the Court otherwise left it to EPA's discretion to determine how emissions increases following a physical change or change in the method of operation were to be determined, including the currency for measuring the emissions increases. *Id.* at 353–54, 401–03.

In using our discretion for defining the component term ''increases in any pollutant emitted'' within the definition of ''modification,'' we are mindful of Congress' directive that the major NSR program be tailored in such a way as to balance the need for environmental protection against the desires to encourage economic growth. In this context, the appropriate methodologies for measuring emissions increases is inherently linked to our responsibility to guide the States in their efforts to achieve and maintain an effective, comprehensive air quality program, of which the major NSR program is only one component. See section 101(a) of the Act. Accordingly, as both we and the States have gained experience in managing air quality, we have amended the applicability provisions of the NSR regulations to better balance the need for environmental protection and economic growth, and the administrative burden of running the program. (See for example 57 FR 32314, July 21, 1992; 67 FR 80186, December 31, 2002; 68 FR 61248, October 27, 2003.)

In light of the progress of air quality programs under the 1990 CAA to reduce EGU emissions and the policy goals of the major NSR program, we considered the appropriate scope of the major NSR program as it applies to existing sources. The NSR program's scope is closely related to the scope of the NSPS program, created 7 years earlier in the CAA Amendments of 1970. In section 111 of the CAA, which sets forth the NSPS provisions, Congress applied the NSPS to ''new sources.'' [CAA sections 111(b)(1)(B), 111(b)(4).] Congress determined that as a general matter it would not impose the NSPS standards on existing sources, instead leaving to the State and local permitting authorities the decision of the extent to which to regulate those sources through ''State Implementation Plans'' designed to implement National Ambient Air Quality Standards (NAAQS). [See CAA section 110.] Congress followed a similar approach in determining the scope of the major NSR program established by the 1977 Amendments to the CAA. As amended, the CAA specifies that State Implementation Plans must contain provisions that require sources to obtain major NSR permits prior to the point of ''construction'' of a source. [CAA sections 172(c)(5); 165(a).] By contrast, the CAA generally leaves to State and local permitting authorities in the first instance the question of the extent, means, and timetable for obtaining reductions from existing sources that are needed to comply with NAAQS. [See CAA sections 172(c)(1), 161.] NSR's applicability to existing sources that undergo a ''modification'' is an exception to this basic concept. This exception likewise finds its roots in the NSPS program's applicability to ''modifications'' of existing sources. The 1970 CAA made the NSPS program applicable to modifications through its definition of a ''new source,'' which it defined as ''any stationary source, the construction or modification of which is commenced after the publication of regulations * * * prescribing a[n applicable] standard of performance * * *.'' [CAA section 111(a)(2).] CAA section 111(a)(4), in turn, defined a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted from such source or which results in the emission of any air pollutant not previously emitted.''

[49] The 1980 rules revised the pre-change (baseline) emissions calculation to one based on actual emissions, but retained potential-to-emit for measuring post-change emissions.

The 1980, 1992 and 2002 rules[50] were reasonable interpretations of the statutory language in CAA section 111(a)(4) for purposes of the major NSR program and the air quality needs of the country at those times, and continue to be reasonable in many respects. Nonetheless, we retain discretion to adopt other constructs for determining emissions increases following a physical change or change in the method of operation when they make sense in particular circumstances. The proposed regulations would establish a uniform emissions test nationally under the NSPS and NSR programs for existing EGUs. They would also streamline requirements for EGUs. Accordingly, we believe that it is appropriate to tailor the major NSR program for EGUs to regulate modifications that result in increases to an EGU's existing capacity. The maximum achievable hourly emissions test is an appropriate tool for this purpose.

The Court in *New York* v. *EPA* held that the language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions, instead of potential or allowable emissions. Slip op. at 64. The Court based its opinion, in part, on the *Alabama Power* Court's finding that the term ''emit'' in the phrase ''emit, or have the potential to emit'' within the definition of major emitting facility, is ''some measure of actual emissions.'' *New York* v. *EPA*, slip op. at 63, citing *Alabama Power*, 636 F.2d at 353 (emphasis added).[51]

To the extent that the *Alabama Power* Court's holding relating to the definition of major emitting facility in CAA section 169(1) should have any persuasive value in interpreting a different component term (increases the amount of any air pollutant) in a different definition [definition of modification in CAA 111(a)(4)] in the Act, the Court's reference to ''some measure of actual emissions'' indicates that the statute allows for different ways of measuring actual emissions.

We believe that the maximum achievable hourly emissions test provides ''some measure of actual emissions.'' For most, if not all EGUs, the amount at which the unit is actually able to emit—its maximum achievable hourly rate—is equivalent to that unit's maximum actual hourly rate during the relevant period. States require most, if not all EGUs, to perform periodic performance tests under applicable State Implementation Plans and enhanced monitoring requirements. The NSPS regulations require a source to conduct testing based on representative performance of the affected facility, generally interpreted as performance at current maximum physical and operational capacity. [40 CFR 60.8(c).][52] Also, in the National Stack Test Guidance that we issued on September 30, 2005, we recommended that facilities conduct performance tests under conditions that are ''most likely to challenge the emissions control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition.'' Most EGUs actually emit at the highest level at which they are capable of emitting at some time within a 5-year baseline period.

One way in which the maximum achievable hourly emissions test differs from the way actual emissions are measured under the current actual-to-projected-actual test is that the former measures actual emissions over an hourly period rather than over an annual period. When Congress enacted the 1977 amendments to the CAA creating the NSR program, it did not specify how increases in emissions were to be calculated, or over what increment of time emissions should be measured. Nonetheless, Congress was likely aware, before it enacted the 1977 Amendments, that we calculated emissions increases in terms of kg/hr to determine whether a project resulted in a ''modification.'' Congress did not indicate anywhere in the 1977 Amendments or the legislative history that our use of a kg/hr measure of emissions would be contrary to the purposes of the NSR program. Accordingly, we believe that we have discretion to determine the appropriate increment of time over which to measure actual emissions for purposes of determining whether emissions increases have occurred in the major NSR program.

We believe that it is reasonable to use an hourly period to calculate actual emissions for purposes of measuring emissions increases in the major NSR program. Prior to Congress' enactment of the major NSR provisions in the CAA Amendments of 1977, the NSPS regulations calculated emissions increases from physical and operational changes in terms of hourly emissions. Our 1975 NSPS regulations provided that ''any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning * * * of the Act,'' with ''emission rate * * * expressed as kg/hr of any pollutant discharged to the atmosphere.'' [40 FR 58416, 58419 (December 16, 1975)] Even before the 1975 NSPS rule, we put forth a definition of ''modification'' in a 1974 regulation implementing what became known as the ''Prevention of Significant Deterioration'' program. [39 FR 42510 (December 5, 1974).] The regulation's preamble further provided that we intended the term ''modified source'' to be ''consistent with the definition used in the [NSPS].'' *Id.* at 42513.

We further believe that today's revised emissions test does not result in a substantially different outcome from the actual-to-projected-actual test. The current major NSR regulations measure actual emissions differently from the emissions test we are proposing by assessing changes in emissions relative to historical emissions over a baseline period defined in terms of annual emissions. Nonetheless, like the NSPS test, the major NSR regulations allow for consideration of an emissions unit's operating capacity in determining whether a change results in an emissions increase. Under the actual-to-projected-actual test, a source can subtract from its post-project emissions those emissions that the unit could have accommodated during the baseline period and that are unrelated to the change (sometimes referred to as the ''demand growth exclusion''). That is, the source can emit up to its current maximum capacity without triggering major NSR under the actual-to-projected-actual test, as long as the increase is unrelated to the physical or operational change. The NSPS approach thus differs from the major NSR test only by when a source considers operating capacity in the methodology, and by assuming that a source's use of existing operating capacity is unrelated to the change.

Although the approaches differ, applying the maximum achievable hourly emissions test for EGUs in the major NSR program has merit because it reduces the administrative burden of the NSR program. It eliminates the burden of projecting future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, because any increase in the emissions under the maximum achievable

[50] 45 FR 52676, August, 7, 1980; 57 FR 32314, July 21, 1992; 67 FR 80186, December 31, 2002. See items 0036, 0027, and 0030 in E-Docket OAR–2005–0163.

[51] As previously stated, the United States has filed a petition for rehearing on this aspect of the Court's decision in *New York* v. *EPA*. See item 0050 in E-Docket OAR–2005–0163.

[52] *See* also 36 FR 24876, December 23, 1971. Referring to performance tests, we stated that ''Procedures have been modified so that the equipment will have to be operated at maximum expected production rate, rather than rated capacity, during compliance tests.''

emissions test would logically be attributed to the change. It reduces recordkeeping and reporting burdens on sources because compliance will no longer rely on synthesizing emissions data into rolling average emissions. In view of this, allowing use of the maximum achievable hourly rate test reasonably balances the economic need of sources to use existing operating capacity with the environmental benefit of regulating those emissions increases related to a change. Moreover, allowing use of this approach for EGUs is a reasonable use of our discretion to define how we measure emissions increases for purposes of the major NSR program, because it reduces administrative burden associated with the emissions calculation procedure, and considers the effectiveness of other regulatory programs in regulating use of existing EGU capacity.

Finally, the test allows sources to undertake projects designed to improve the efficiency, reliability, and safety of the EGU without necessitating a finding that post-change emissions at such a unit are unrelated to regulated physical or operational changes. In our 2003 final rule on the Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion for NSR (68 FR 61248, October 27, 2003), we articulated our position that activities designed to promote safety, reliability, and efficiency of emissions units should not be subject to major NSR, yet it is often these types of projects that raise questions as to whether post-change emissions are related to a change. The maximum achievable hourly emissions test encourages sources to undertake such projects by focusing reviewing authority resources on changes that add new operating capacity rather than on projects that restore a source to normal operations. Importantly, short-term emissions are a good indicator for operating capacity. That is, longer averaging periods, such as an annual basis, can mask spikes in production.

2. Maximum Achieved Hourly Emissions Test

As we stated in Section IV.B. of this preamble, we also believe that, like the maximum achievable hourly emissions test, the maximum achieved emissions test is a measure of a source's actual emissions. The maximum achieved hourly emissions test is based on a specific measure of historical actual emissions during a representative period. Therefore, even though it is not our preferred option, we believe that a test based on maximum achieved hourly emissions satisfies the requirement that major NSR applicability be based on ''some measure of actual emissions.'' For the reasons that we state in Section V.C.1 of this preamble, we believe we have discretion to adopt a maximum hourly achieved emissions test for determining whether there is an increase in emissions following a physical change or change in the method of operation. We request comment on this option and on whether it satisfies the requirement that major NSR applicability be based on a measure of actual emissions.

We request public comment on all aspects of the legal basis in today's proposed action.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866—Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers this a ''significant regulatory action'' within the meaning of the Executive Order. EPA has submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 1230.18.

Certain records and reports are necessary for the State or local agency (or the EPA Administrator in non-delegated areas), for example, to: (1) Confirm the compliance status of stationary sources, identify any stationary sources not subject to the standards, and identify stationary sources subject to the rules; and (2) ensure that the stationary source control requirements are being achieved. The information would be used by the EPA or State enforcement personnel to (1) identify stationary sources subject to the rules, (2) ensure that appropriate control technology is being properly applied, and (3) ensure that the emission control devices are being properly operated and maintained on a continuous basis. Based on the reported information, the State, local, or tribal agency can decide which plants, records, or processes should be inspected.

The proposed rule would reduce burden for owners and operators of major stationary sources. While we do not expect a change in the number of permit actions due to the proposed changes, we expect the proposed rule would simplify applicability determinations, eliminate the burden of projecting future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, and reduce recordkeeping and reporting burdens. Over the 3-year period covered by the ICR, we estimate an average annual reduction in burden of about 5,870 hours and $462,000 for all industry entities that would be affected by the proposed rule. For the same reasons, we also expect the proposed rule to reduce burden for State and local authorities reviewing permits when fully implemented. However, there would be a one-time, additional burden for State and local agencies to revise their SIPs to incorporate the proposed changes. We estimate this one-time burden to be about 2,240 annual hours and $83,000 for all State and local reviewing authorities that would be affected by this proposed rule.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purpose of responding to the information collection; adjust existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. We will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfies the requirements of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizine respondent burden, including use of automated collection techniques, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number OAR–2005–1064. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after October 20, 2005, a comment to OMB is best assured of having its full effect if OMB receives it by November 21, 2005. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's notice on small entities, small entity is defined as: (1) A small business that is a small industrial entity as defined in the U.S. Small Business Administration (SBA) size standards. (*See* 13 CFR 121.201); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's notice on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. sections 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect, on all of the small entities subject to the rule.

We believe that today's proposed rule changes will relieve the regulatory burden associated with the major NSR program for all EGUs, including any EGUs that are small businesses. This is because the proposed rule would simplify applicability determinations, eliminate the burden of projecting future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, and by reducing recordkeeping and reporting burdens. As a result, the program changes provided in the proposed rule are not expected to result in any increases in expenditure by any small entity.

We have therefore concluded that today's proposed rule would relieve regulatory burden for all small entities. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule would not contain a Federal mandate that would result in expenditures of $100 million or more by State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Although initially these changes are expected to result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, these revisions would ultimately simplify applicability determinations, eliminate the burden of reviewing projected future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, and reduce the burden associated with making compliance determinations. Thus, today's action is not subject to the requirements of sections 202 and 205 of the UMRA.

For the same reasons stated above, we have determined that today's notice contains no regulatory requirements that might significantly or uniquely affect small governments. Thus, today's action is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132—Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This proposed rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. We estimate an one-time burden of approximately 2,240 hours and $83,000 for State agencies to revise their SIPs to include the proposed regulations. However, these revisions would ultimately simplify applicability determinations, eliminate the burden of reviewing projected future emissions and distinguishing between emissions increases caused by the change from those due solely to demand growth, and reduce the burden associated with making compliance determinations. This will in turn reduce the overall burden of the program. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications, as specified in Executive Order 13175. There are no Tribal authorities currently issuing major NSR permits. To the extent that today's proposed rule may apply in the future to any EGU that may locate on tribal lands, tribal officials are afforded the opportunity to comment on tribal implications in today's notice. Thus, Executive Order 13175 does not apply to this rule.

Although Executive Order 13175 does not apply to this proposed rule, EPA specifically solicits comment on this proposed rule from tribal officials. We will also consult with tribal officials, including officials of the Navaho Nation lands on which Navajo Power Plant and Four Corners Generating Plant are located, before promulgating the final regulations.

G. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045: ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This rule is not subject to Executive Order 13045, because we do not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. We believe that, based on our analysis of electric utilities, this rule as a whole will result in equal environmental protection to that currently provided by the existing regulations, and do so in a more streamlined and effective manner.

H. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' [66 FR 28355 (May 22, 2001)] because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. In fact, this rule improves owner/operator flexibility concerning the supply, distribution, and use of energy. Specifically, the proposed rule would increase owner/operators' ability to utilize existing capacity at EGUs.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

Today's proposed rule does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

List of Subjects in 40 CFR Parts 51 and 52

Environmental protection, Administrative practice and procedure, Air pollution control, Electric Generating Unit, BACT, LAER, Nitrogen oxides, Sulfur dioxide, BART, Clean Air Interstate Rule.

Dated: October 13, 2005.

Stephen L. Johnson,

Administrator.

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