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Part V

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New Stationary Sources; Industrial-Commercial Institutional Steam Generating Units; Proposed Revision of Rule and Denial of Petitions for Reconsideration

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-3483-2]

Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed revision of rule.

SUMMARY: On November 25, 1986, standards of performance were promulgated limiting emissions of particulate matter (PM) and nitrogen oxides (NO_x) from industrial-commercial-institutional steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour) (51 FR 42768). Petitions for reconsideration of the NO_x standards were submitted by the Utility Air Regulatory Group (UARG) and owners of the William H. Zimmer Generating Station (Cincinnati Gas & Electric Company, Columbus and Southern Ohio Electric Company, and the Dayton Power and Light Company; hereafter "Zimmer owners"), which presented information pertaining to steam generating units that operate at very low annual capacity factors. Consideration of these data and information has led to today's proposal to establish revised NO_x performance testing and monitoring requirements for steam generating units with heat input capacities of greater than 73 MW (250 million Btu/hour) that fire natural gas, distillate oil, and low nitrogen residual oil and that operate at very low annual capacity factors (i.e., less than 10 percent). In addition, today's proposal would also exempt steam generating units with heat input capacities of less than 73 MW (250 million Btu/hour) that fire natural gas, distillate oil, and low nitrogen residual oil and that operate at very low annual capacity factors (i.e., less than 10 percent) from the NO_x standards and performance testing and monitoring requirements.

DATES: *Comments.* Comments on the proposed changes must be received by March 10, 1989.

Public hearing. If anyone requests to speak at a public hearing by February 2, 1989, a public hearing will be held on February 9, 1989, beginning at 10:00 a.m. Persons interested in attending the hearing should call Ms. Ann Eleanor at (919) 541-5578 to verify that a hearing will be held. Assistance will be available for persons with hearing impairments.

Request to speak at hearing. Persons wishing to present oral testimony must request to speak at the public hearing by February 2, 1989.

ADDRESSES: *Comments.* Comments on the proposed changes should be submitted (in duplicate, if possible) to: Central Docket Section (LE-131), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. Attention: Docket Number A-79-02.

Public hearing. If anyone requests a public hearing, it will be held at the EPA's Office of Administration Auditorium, Research Triangle Park, North Carolina. Persons interested in attending the hearing or wishing to present oral testimony should notify Ms. Ann Eleanor, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

Docket. Docket Number A-79-02, containing supporting information used in developing the proposed revision, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at the EPA's Central Docket Section, South Conference Center, Room 4, Waterside Mall, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter [(919) 541-5251] Standards Development Branch, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

Criteria for Review of the Petitions for Reconsideration

The standards were promulgated under the procedures of section 307 of the Clean Air Act. The petitioners (i.e. UARG and Cincinnati Gas & Electric Company) have requested reconsideration under section 307(d)(7)(B) of the Act. Section 307(d)(7)(B) provides that "if the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the comment period] if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule [ ]." As the relevant House report explains, the purpose of section 307(d)(7)(B) is to provide the Agency an opportunity "to pass on the significance of the [new] materials and determine whether supplementary proceedings are called for or not." Legislative History of the Clean Air Act Amendments of 1977, Volume 4, p. 2790.

In EPA's view, such objections are of central relevance only if they provide substantial support for the argument that the standards should be revised. *See* Denial of Petition to Revise NSPS for Stationary Gas Turbines, 45 FR 81653 (December 11, 1980); Response to Petition for Reconsideration and Final Amendments, NSPS for Petroleum Dry Cleaners, 50 FR 49022 (November 27, 1985).

In reviewing the reconsideration petitions of UARG and Cincinnati Gas & Electric Company, EPA has considered whether under section 307(d)(7)(B) of the Act, the petitions presented EPA with new material of central relevance to the rule that could not have been presented before.[1] As is discussed in detail elsewhere in today's **Federal Register**, it has decided that none of the petitions present that kind of material. Nevertheless, the Administrator has discretionary authority to reconsider or amend a rule at any time. The Administrator has determined that with respect to one issue raised by Cincinnati Gas & Electric and UARG—the NO_x standard as applied to low capacity steam generating units burning certain oils or natural gas—EPA agrees with UARG and the Zimmer owners. The proposed rule exempted all units, regardless of size or fuel consumed, from continuous emission monitors (CEM) requirements for NO_x if they operated at 30 percent capacity or less. The final rule modified the CEM exemption. It deleted the capacity factor criterion and substituted criteria related to size and fuel consumption in order to better fit the CEM requirement to the units most likely to generate large

[1] Section 4(d) of the Administrative Procedure Act (APA), U.S.C. 553(e), states "Each agency shall give an interested person the right to petition for issuance, amendment or repeal of a rule." Although section 4(d) of the APA also establishes a right to petition for administrative reconsideration, that provision almost certainly does not apply to petitions for reconsideration of regulations that are promulgated pursuant to the rulemaking provisions of section 307(d) of the Clean Air Act. *See* section 307 (d)(1)(N), 42 U.S.C. 7607(d)(1)(N). ("The provision of section 553 through 557 * * * of title 5 of the United States Code shall not, except as expressly provided in this subsection, apply to action to which evaluating the petition for reconsideration under the APA are essentially the same as those for section 307(d)(7)(B) petitions. *See* Denial of Petition to Revise NSPS for Stationary Gas Turbines, 45 FR 81653-54, and decision cited therein.

quantities of NO_x. Upon further consideration, EPA agrees that it is not reasonable to require continuous emission monitoring of emissions from very low capacity factor steam generating units—even large ones—using certain low nitrogen fuels (very low nitrogen residual oil, distillate oil and natural gas). For that reason, EPA is proposing to revise the rule to require initial performance testing and annual testing of large steam generating units and is proposing to exempt small steam generating units from NO_x standards. The basis for and the details of the proposed action are discussed below.

Rationale for Proposed Amendments

The UARG and the Zimmer owners submitted petitions for reconsideration requesting changes to the promulgated NO_x standards as they applied to utility auxiliary steam generating units. As promulgated, the standards limited NO_x emissions from industrial-commercial-institutional steam generating units with heat input capacity greater than 29 MW (100 million Btu/hour) for which consideration commenced after June 19, 1984 (51 FR 42768).

As identified by the petitioners, utility auxiliary units are used at power plants to assist in start-up of the main steam generating unit. These auxiliary units operate infrequently and typically exhibit very low annual capacity factor levels. The petitions stated that the NO_x standards would impose an unreasonable burden on these steam generating units. They, therefore, requested that the final NO_x standards be amended to either: (1) Exempt utility auxiliary steam generating units from the NO_x standards; (2) exempt steam generating units from the NO_x standards that operate at very low annual capacity factor levels, such as 10 percent or less; or (3) reduce the burden imposed by the performance testing and monitoring requirements associated with the NO_x standards on steam generating units that operate at such very low annual capacity factors.

In support of its petition, UARG submitted data for 20 utility auxiliary steam generating units planned for construction in the 1985 to 1995 time period which would be subject to the NO_x standards, as promulgated. The annual capacity factor of these units was generally in the range of 5 to 8 percent, although several were as low as 2 and 3 percent.

Review of a survey of owners/operators of new industrial steam generating units constructed between 1981 and 1984, which the Agency conducted in 1986–1987, indicates that utility auxiliary units are not the only type of steam generating units that operate at such low capacity factors. A limited number of industrial steam generating units also operate at very low annual capacity factors of 10 percent or less. These industrial units function as stand-by or back-up steam generating units that are operated only when the primary steam generating unit must be taken out of operation for some reason. The impacts of the promulgated NO_x standards on steam generating units that operate at very low annual capacity factors are essentially the same whether the units are utility auxiliary units or industrial stand-by or back-up units. Consequently, the same provisions should apply to both utility auxiliary and industrial-commercial-institutional steam generating units.

Review of the data submitted by the petitioners, as well as that contained in the survey mentioned above, indicates that very low annual capacity factor steam generating units tend to fire "clean" fuels such as natural gas, distillate oil, or low nitrogen residual oils (i.e., residual oils with nitrogen contents of 0.30 weight percent or less). Combustion of these "clean" fuels results in much lower NO_x emissions than combustion of "dirty" fuels, such as high nitrogen residual oils or coal. Therefore, special provisions applicable to very low annual capacity factor steam generating units should be limited to those units firing "clean" fuels in order to minimize NO_x emissions from such units.

With these considerations in mind, the impacts associated with the promulgated NO_x standards were reviewed for steam generating units firing natural gas, distillate oil, and low nitrogen residual oil at very low annual capacity factors (i.e., less than 10 percent). The impacts were reviewed in terms fo the annual cost of NO_x control (including the performance testing and monitoring requirements), the potential NO_x reduction from these units, and the cost effectiveness of the NO_x standards.

As promulgated, the NO_x standards for a typical steam generating unit with a heat input capacity of 73 MW (250 million Btu/hour) or less and firing natural gas, distillate oil, or low nitrogen residual oil are based on low excess air (LEA) operation. The standards require a 30-day intitial performance test, continuous monitoring of either NO_x emissions or combustion parameters indicative of NO_x emissions, and the submittal of quarterly excess emission reports (semiannual reports if no excess emissions occurred). The NO_x standards for a large steam generating unit with a heat input capacity greater than 73 MW (250 million Btu/hour) and firing natural gas, distillate oil, or low nitrogen residual oil are based on staged combustion and low NO_x burners. The standards require a 30-day initial performance test, continuous monitoring of NO_x emissions using a continuous emission monitoring system (CEMS) for continuous compliance (including Appendix F quality assurance procedures), and the submittal of quarterly reports including emissions data and the results of the Appendix F procedures.

Thus, the population of industrial-commercial-institutional steam generating units subject to the promulgated NO_x standards can be divided into two groups for analysis. The impacts on a typical steam generating unit [i.e., one with heat input capacities between 29 MW (100 million Btu/hour) and 73 MW (250 million Btu/hour)] can be considered by examining a steam generating unit with a heat input capacity of 44 MW (150 million Btu/hour). The impacts on a large steam generating unit [i.e., one with a heat input capacity of greater than 73 MW (250 million Btu/hour)] can be considered by examining a steam generating unit with a heat input capacity of 117 MW (400 million Btu/hour).

For a typical steam generating unit with a heat input capacity of 44 MW (150 million Btu/hour), operating at 10 percent annual capacity factor, using LEA as the NO_x control technique, and firing natural gas, distillate oil, or low nitrogen residual oil, the annual cost associated with the NO_x standards (control equipment, performance test, and monitor) would be $65,000 to $75,000 per year. For a large-sized steam generating unit with a heat input capacity of 117 MW (400 million Btu/hour), operating at 10 percent annual capacity factor, using staged combustion or low NO_x burners to control NO_x emissions, and firing natural gas, distillate oil, or low nitrogen residual oil, the annual cost would be $130,000 to $150,000 per year. The NO_x reductions that would be achieved by these steam generating units would be less than 2 tons per year for the typical unit and approximately 20 tons per year for the large unit.

The estimated emission reductions associated with the standards are notable for the large steam generating unit. The cost effectiveness of NO_x control for these very low capacity units, however, appears to be quite high [i.e., $5,000 to $8,000 per ton of NO_x for the large 117 MW (400 million Btu/hour) unit and $43,000 to $49,000 per ton of NO_x for the typical 44 MW (150 million

Btu/hour) unit]. Since the cost effectiveness of NO_x control is "driven,"in this case, by the cost of the performance testing and monitoring requirements, the impacts associated with alternative and less burdensome performance testing and monitoring requirements were analyzed.

To derive these cost estimates, EPA assumed that all very low capacity factor units would vent to the atmosphere 100 percent of the steam generated in performance tests. Thus, the fuel used to fire these units is a major component of the cost of complying with the performance testing requirements of the current standards. The EPA solicits comments on the approach used to determine the cost effectiveness, especially the assumption that all steam would be vented to the atmosphere.

The application of NO_x control through the use of techniques such as LEA or staged combustion generally makes combustion more difficult to sustain in a steam generating unit. Thus, the unit generally becomes more difficult to operate and requires more frequent and greater operator attention. The natural tendency, therefore, is for the operator to decrease the amount of LEA or staged combustion in order to make operation of the steam generating unit easier. As this occurs, NO_x emissions increase and NO_x emission reductions decrease.

As a result, continuous monitoring of NO_x emissions (either directly by the use of a continuous emission monitor, or indirectly by monitoring combustion parameters indicative of NO_x emissions) is necessary to provide complete assurance of NO_x emission reductions. As the frequency of NO_x monitoring decreases, the assurance of actual NO_x emission reductions decreases, and the NO_x standards become less meaningful.

The only alternative to continuous monitoring of NO_x is periodic, short-term NO_x performance tests. Because this alternative is less rigorous than continuous monitoring, however, it will undoubtedly lead to some increase in NO_x emissions above the levels that could be maintained through the use of continuous monitoring. Despite this drawback, periodic short term performance tests are a useful tool for enforcement and will permit enforcement personnel to monitor periodically the compliance status of steam generating units operating at very low annual capacity factors.

The requirement of an initial 24-hour NO_x performance test followed by 3-hour NO_x performance tests (conducted annually or after every 400 hours of operation, whichever comes first) reduces the cost effectiveness of the NO_x standards to about $300 per ton for a large steam generating unit. For a typical steam generating unit, however, even these requirements result in a NO_x cost effectiveness greater than $3,000 per ton.

The changes being proposed today, therefore, would amend the promulgated NO_x standards in two ways. First, less burdensome performance testing and monitoring requirements for NO_x emissions are proposed for large steam generating units [i.e., those greater than 73 MW (250 million Btu/hour) heat input] firing natural gas, distillate oil, or low nitrogen residual oil (either alone or in combination), and operating at 10 percent annual capacity factor or less. These units would be required to perform an initial short-term performance test (minimum 24-hour) for NO_x emissions within 60 days after achieving the maximum production rate, but not later than 180 days after initial start-up to demonstrate compliance with the NO_x standards and to confirm their maximum heat input capacity. This initial test would be followed by a short-term (minimum 3-hour) NO_x performance test (conducted annually or after every 400 hours of operation, whichever comes first) to verify continued compliance using Method 7, 7A, or other approved methods, or using a CEMS.

Second, an exemption from the NO_x standards and monitoring requirements is proposed for typical steam generating units [i.e., those of less than 73 MW (250 million Btu/hour) heat input] that fire natural gas, distillate oil, or low nitrogen residual oil (either alone or in combination), and operate at 10 percent annual capacity factor or less. The reason for the exemption is the lack of a cost-effective method of monitoring No_x emissions. These units would be required, however, to perform an initial short-term test (minimum 24-hour) to confirm their maximum heat input capacity. This is necessary to ensure that these steam generating units will, in fact, operate at 10 percent annual capacity factor or less. Sources will also be required to maintain fuel records to demonstrate that they are using the "clean" fuels.

The estimated increase in No_x emissions resulting from the proposed exemption for typical steam generating units is less than 50 tons per year. The promulgated standards projected approximately 25,000 tons of NO_x reduction per year in the fifth year following promulgation. This proposed revision would affect fewer than 30 steam generating units out of the 604 units projected to be constructed in the 5 years following promulgation. No solid waste or liquid waste environmental impacts are associated with these proposed revisions.

Miscellaneous

Under Executive Order 12291, a rulemaking action must be examined to determine if it is a "major rule" and, therefore, subject to certain requirements of the Order. Today's rulemaking action would result in none of the adverse economic effects set forth in section 1 of the Order as grounds for finding a regulation to be a "major rule." This rulemaking action would result in a reduced burden on the industrial-commercial-institutional steam generating unit source category. It would not result in any increase in costs or prices and would not disrupt market competition. This revision, therefore, would not be a "major rule" under Executive Order 12291.

Under section 317 of the Clean Air Act, an economic impact assessment must be prepared for revisions that are determined to be substantial. These revisions are not substantial; as a result, an economic impact assessment has not been prepared.

Pursuant to 5 U.S.C. 605(b), the Administrator certifies that these revisions would not have a significant impact on a substantial number of small entities. The revisions would reduce the burden on this source category, and it has already been determined that, in the absence of these revisions, the standards would not affect a substantial number of small entities (51 FR 42787 and 42788, November 25, 1986).

Paperwork Reduction Act

Changes to the information requirements as proposed in today's notice 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.* An Information Collection Request document has been prepared by EPA (ICR No. 1088) and a copy may be obtained by writing Carla Levesque, Information Policy Branch, Environmental Protection Agency, 401 M Street, SW. (PM-223), Washington, DC 20460 or by calling (202) 382-2468.

Public reporting burden for this collection of information is estimated to decrease 800 hours for large steam generating units [i.e., those greater than 73 MW (250 million Btu/hour) heat input] that fire natural gas, distillate oil, or low nitrogen residual oil (either alone or in combination), and operate at 10 percent annual capacity factor or less and 3,700 hours for steam generating units with less than 73 MW (250 million Btu/hour) heat input that also fire natural gas, distillate oil, or low nitrogen residual oil (either alone or in combination), and operate at 10 percent annual capacity factor or less.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch, PM-223, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Paperwork Reduction Project (2060-1088), Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA." The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

List of Subjects in 40 CFR Part 60

Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Date: January 6, 1989.

Lee M. Thomas,
Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for Part 60 continues to read as follows:

Authority: 42 U.S.C. 7411, 7414, and 7601(a).

2. Section 60.44b is amended by revising the first phase of paragraphs (a) and (b) and adding paragraphs (i), (j), and (k) as follows:

§ 60.44b Standard for nitrogen oxides.

(a) Except as provided under paragraph (k) of this section, * * *

(b) Except as provided under paragraph (k) of this section, * * *

* * * * *

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities meeting the following three criteria:

(1) combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) are subject to a Federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraph (j) of this section, and that have a heat input capacity of 73 MW (250 million Btu/hour) or less, are not subject to the nitrogen oxides emission limits under this section.

3. Section 60.46b is amended by revising paragraph (c) and adding paragraphs (g) and (h) as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(c) Compliance with the nitrogen oxides emission standards under § 60.44b shall be determined through performance testing under paragraph (e), (f), or (g) and (h) of this section, as applicable.

* * * * *

(g) The owner or operator of an affected facility described in § 60.44b(j) or 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test for affected facilities that meeting the criteria of § 60.44b(j). It will be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meet the criteria of § 60.44b(k). Subsequent demonstrations may be required at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacture is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) shall:

(1) conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the nitrogen oxides emission standards under § 60.44b using Method 7, Method 7A, or other approved reference methods, or using a continuous emission monitoring system (CEMS); and

(2) determine nitrogen oxides emissions after the initial performance test once per calendar year or every 400 hours of operation (whichever comes first) using Method 7, Method 7A, or other approved reference methods, or using a continuous emission monitoring system (CEMS).

4. Section 60.48b is amended by revising paragraph (b) and adding paragraph (i) as follows:

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

* * * * *

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standards under § 60.44b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere and record the output of the system.

* * * * *

(i) The owner or operator of an affected facility described in §§ 60.44b(j) or 60.44b(k) is not required to install or operate a continuous monitoring system to measure nitrogen oxides emissions.

5. Section 60.49b is amended by revising paragraphs (a)(2), (b), (e), and the introductory text of paragraph (g) and adding paragraphs (p) and (q) as follows:

§ 60.49b Reporting and recordkeeping requirements.

(a) * * *

(2) if applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), 60.43b(a)(3)(iii), 60.43b(c)(2)(ii), 60.43b(d)(2)(iii), 60.44b(c), 60.44b(d), 60.44b(e) 60.44b(i), 60.44b(j), 60.44b(k), 60.45b(d), 60.46b(g), 60.46b(h), or 60.48b(i),

* * * * *

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under §§ 60.42b, 60.43b, and 60.44b, shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in Appendix B. The owner or operator of each affected facility described in §§ 60.44b(j) or 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

* * * * *

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or 60.44b(k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content on a per calendar quarter basis. The nitrogen content shall be determined using ASTM Method D3431-80, Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons (IBR—see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

* * * * *

(g) Except as provided under paragraph (p) of this section, the owner and operator of an affected facility subject to the nitrogen oxides standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

* * * * *

(p) The owner or operator of an affected facility described in §§ 60.44b(j) or 60.44b(k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The number of hours of operation.

(q) The owner or operator of an affected facility that meets the criteria under §§ 60.44b(j) or 60.44b(k) shall submit to the Administrator on a quarterly basis:

(1) Results of any nitrogen oxides emission tests required during the quarter,

(2) The annual capacity factor over the previous twelve months,

(3) The average fuel nitrogen content during the quarter, if residual oil was fired; and,

(4) If the affected facility meets the criteria described in § 60.44b(j), the hours of operation during the quarter and the hours of operation since the last nitrogen oxides emission test.

[FR Doc. 89-700 Filed 1-12-89; 8:45 am]
BILLING CODE 6560-50-M

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40 CFR Part 60

[AD-FRL-3504-9]

Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Denial of petitions for reconsideration.

SUMMARY: New source performance standards (NSPS) for new, modified, and reconstructed industrial-commercial-institutional steam generating units with heat input capacities of more than 29 MW (100 million Btu/hour) [other than those subject to Subpart Da] were promulgated on November 25, 1986 (51 FR 42768), as Subpart Db of 40 CFR Part 60. These standards limited emissions of particulate matter (PM) from industrial-commercial-institutional steam generating units firing coal, wood, and municipal solid waste, and nitrogen oxides (NO_x) emissions from steam generating units firing natural gas, oil, coal, and waste by-product fuels. Additional standards promulgated on December 16, 1987 (52 FR 47826), limited emissions of sulfur dioxide (SO_2) from industrial-commercial-institutional steam generating units firing coal and oil, and PM emissions from units firing oil.

Petitions requesting reconsideration of the standards of performance promulgated on November 25, 1986, were submitted to the Agency in January 1987 by the Council of Industrial Boiler Owners (CIBO), Utility Air Regulatory Group (UARG), and the owners of the William H. Zimmer Generating Station (Cincinnati Gas & Electric Company, Columbus and Southern Ohio Electric Company, and the Dayton Power and Light Company, referred to hereinafter as the Zimmer owners). Petitions requesting reconsideration of the standards of performance promulgated on December 16, 1987, were submitted to the Agency in February, March, and May 1988, by CIBO, Hawaiian Electric Company (HECO), the Zimmer owners, and the American Paper Institute (API) together with the National Forest Products Association (NFPA).

The issues raised by these petitioners do not meet the criteria for reconsideration of the rule as set out in section 307(d)(7)(B) of the Clean Air Act (CAA or the Act). The petitioners neither raised new objections that were impractical to present during the specified comment period nor presented new material of central relevance to the outcome of the rule. Because these petitions do not provide substantial support for revising the standards of performance promulgated on November 25, 1986, and December 16, 1987, they are being denied in today's notice. However, using his discretionary authority to reconsider and amend a rule, the Administrator has decided that sufficient reason exists and, therefore, is proposing revisions to parts of the NO_x rule. (The rationale for this decision is explained more fully in a separate **Federal Register** notice.) These proposed revisions are discussed elsewhere in today's **Federal Register**.

DATES: The denial of the petitions to reconsider these standards is a final action under sections 307(b)(1) and 307(d)(7)(B) of the CAA. Review of the denial is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia within 60 days of today's publication, as provided in section 307(b)(1).

ADDRESSES: Docket Nos. A-79-02 (PM/NO_x) and A-83-27 (SO_2) are available for public inspection and copying between 8:00 a.m. and 4:30 p.m., Monday through Friday, at Central Docket Section, South Conference Center, Room 4, Waterside Mall, 401 M Street SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: For further information contact Mr. Fred Porter [(919) 541-5251], Standards Development Branch, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

Standards of performance for PM and NO_x emissions from industrial-commercial-institutional steam generating units were promulgated on November 25, 1986 (51 FR 42768), and for SO_2 emissions on December 16, 1987 (52 FR 47826). Subsequently, seven groups petitioned the Administrator pursuant to section 307(d)(7)(B) of the CAA to reconsider certain requirements of these standards.

These standards of performance implement section 111 of the Clean Air

Act and are based on the Administrator's determination that industrial-commercial-institutional steam generating units cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Industrial-commercial-institutional steam generating units, as a source category, are the second largest stationary source of PM, NO_x, and SO_2 emissions from fuel combustion in the nation, ranking only behind electric utility steam generating units. Further, they were the highest ranked source of PM and SO_2 emissions and the second highest ranked source of NO_x emissions in the NSPS priority list adopted in 1980. The standards, as promulgated, reflect the Administrator's determination of the reduction in emissions (i.e., PM, NO_x, and SO_2) achievable by the best demonstrated system of continuous emission reduction considering costs, nonair quality health and environmental impacts, and energy requirements. [*See* CAA section 111(a)(1)(C).] The basis for specific components of the standards as promulgated were set forth in the preambles to the final rules (51 FR 47268 and 52 FR 47826) and the various background documents referred to in the promulgation notices and contained in the record. In certain cases, specific percentage reduction requirements were determined to be unreasonable. Emission limits, however, remain applicable.

By and large, the petitions submitted by the parties challenge various individual pieces of data, conclusions made by the Agency, or interpretations of the data. For the most part, the petitions simply restate or expand on issues raised and considered during the comment period or present issues that could have been raised during the comment period. To the extent that new issues are raised (e.g., the effect of the "new boiler survey" on the PM standards), the petitioners' contentions are either without merit, or even if true, do not affect the outcome of the rule. Although most of the contentions raised in the petitions could be rejected summarily, the Agency, in the notice below, has endeavored to provide a comprehensive response to the contentions.

Three groups petitioned for reconsideration of the promulgated PM/NO_x standards. CIBO (Docket No. A-79-02, Docket Item VI-D-2) sought reconsideration on the basis that the interrelationship with the SO_2 standards was not considered, the environmental and economic impacts of the standards were overstated, new information gathered in the Agency's own "Survey of New Industrial Boiler Projects 1981-1984" (referred to hereinafter as the "new boiler survey") (Docket No. A-83-27, Item IV-A-4) was not considered, and certain aspects of the Industrial Fuel Choice Analysis Model (IFCAM) were not valid. The Zimmer owners (Docket No. A-79-02, Docket Item VI-D-6) petitioned for reconsideration of the PM/NO_x standards on the basis that NO_x limits on electric utility auxiliary steam generating units are unreasonable and distillate oil NO_x standards cannot be achieved. UARG (Docket No. A-79-02, Docket Items VI-D-1 and IV-D-4) petitioned for reconsideration on the basis that NO_x limits on electric utility auxiliary steam generating units are unreasonable.

Five groups petitioned for reconsideration of the promulgated SO_2 standards. CIBO (Docket No. A-83-27, Item VI-A-1) petitioned on the basis that the standards are inconsistent with the 1977 amendments to the CAA, national energy policy was not considered, the performance of fluidized bed combustion (FBC) and lime spray drying flue gas desulfurization (FGD) systems was not demonstrated, new information on waste disposal impacts was discovered after the comment period closed, the exemption from percent reduction requirements for noncontinental areas is arbitrary, new analyses made available after proposal of the standard (especially information from the "new boiler survey") were not given sufficient consideration, and informal vendor statements were used to support the requirement for 90 percent SO_2 reduction. The Zimmer owners (Docket No. A-83-27, Item VI-A-4) petitioned on the basis that the impacts of a 130 ng/J (0.30 lb/million Btu) heat input emission limit for SO_2 on two oil-fired electric utility auxiliary steam generating units at the Zimmer Station are unreasonable. HECO (Docket No. A-83-27, Item VI-A-5) requested reconsideration on the basis that the impacts of a 130 ng/J (0.30 lb/million Btu) heat input emission limit for SO_2 on oil-fired steam generating units in Hawaii are unreasonable. API and NFPA (Docket No. A-83-27, Item VI-A-6) sought reconsideration on the basis that the lack of provisions for start-up, shutdown, and malfunction is unreasonable.

The next section of today's notice discusses the content of each petition relative to the criteria set forth in section 307(d)(7)(B) of the CAA for requiring the Administrator to convene a proceeding to reconsider the promulgated standards. Following that section, the notice addresses the technical merit of each issue raised in the petitions.

This notice is organized as follows:

I. Review of Petitions for Reconsideration Under Section 307 of the Clean Air Act

A. Criteria for Reconsideration under Section 307

Review of these petitions for reconsideration was carried out according to the procedures of section 307 of the Clean Air Act. Section 307(d)(7)(B) provides that:

> [i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the comment period] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule. . . .

As the relevant House report explains, the purpose of section 307(d)(7)(B) is to provide the Agency an opportunity "to pass on the significance of the [new] materials and determine whether supplementary proceedings are called for or not." (See "Legislative History of the Clean Air Act Amendments of 1977," Volume 4, p. 2790.)

Objections are of central relevance only if they provide substantial support for the argument that the standards should be revised. [See Denial of Petition to Revise NSPS for Stationary Gas Turbines, 45 FR 81653 (December 11, 1980); Response to Petition for Reconsideration and Final Amendments, NSPS for Petroleum Dry Cleaners, 50 FR 49022, (November 27, 1985).] Using the section 307(d)(7)(B) criteria, each of the seven petitions was reviewed to determine whether material of central relevance to the rule was presented that could not have been presented during the comment period. For reasons summarized below and detailed later in this notice, it is apparent that none of the petitions presents this kind of material. In a separate notice in today's **Federal Register**, however, the Administrator is exercising his discretionary authority to propose revised rules for monitoring NO_x emission from very low capacity factor steam generating units.[1]

B. Summary of PM/NO$_x$ Reconsideration Petitions

1. UARG

UARG submitted a petition contending that EPA did not respond to the specifics of arguments it had made on the proposed rule. Further, UARG supplemented this petition with arguments that no standards should be imposed on very low capacity factor utility auxiliary steam generating units. UARG also sought deletion of the monitoring requirements on the grounds that the requirements cannot be applied readily to units that are used infrequently.

These arguments do not compel reconsideration under section 307. First, a claim that EPA's response to comments was incomplete does not trigger section 307 reconsideration. Second, the information provided in UARG's "supplement" could have been provided during the comment period. The same is true of the arguments concerning monitoring. UARG's comments are discussed in Section III below.

2. Zimmer Owners

The Zimmer owners argued that EPA failed to address their comments on the proposed standards. In a supplement dated June 29, 1987, 7 months after the standards were promulgated, the Zimmer owners argued that the standards should not apply to utility auxiliary units for legal and economic reasons.

As the Zimmer owners themselves seemed to recognize, their reconsideration comments generally repeated and expanded on arguments raised during the comment period. Such comments do not compel reconsideration under section 307. The Zimmer owners' comments are discussed in Section III below.

3. CIBO

CIBO argued that two post-proposal developments in the SO_2 proceeding compel reconsideration of the PM/NO$_x$ rule under section 307. The two developments were EPA's proposal of an "interrelated" SO_2 standard after proposal (but before promulgation) of the PM/NO$_x$ standards and the imminent (in early 1987) completion of a "new boiler survey" in the SO_2 rulemaking.

These developments do not compel reconsideration under section 307 because they do not constitute information of central relevance to the outcome of the PM/NO$_x$ rulemaking. EPA has long recognized and taken into account the interrelated character of the PM/NO$_x$ and SO_2 rules. CIBO's argument, therefore, does not provide new information. The only respect in which the argument could be considered new is in CIBO's conjecture that the NO_x standard could be violated in steam generating units designed for firing pulverized coal (PC) when using natural gas or oil. As explained below in Section III, however, EPA believes that compliance with the NO_x standards can be readily accomplished by such units, and CIBO has provided no data to support its comments. CIBO's comments on the interrelationship of the PM/NO$_x$ and SO_2 rules are discussed in Section III below.

CIBO's claims that the projections of new units were too high and its conjectures regarding the "new boiler survey" do not compel reconsideration under section 307. As explained in Section III below, new projections of the absolute number of new and replacement steam generating units are informative, but far less important in regulatory analysis than the relative balance between costs and benefits. When deciding whether or not to regulate, it is the relative balance between costs and benefits that is of primary importance rather than the absolute numbers. However, even with lower projections of the number of new units, the emission reductions achieved by the standards are significant. Conjecture regarding the methods of the "new boiler survey" is also not a basis for mandatory reconsideration absent compelling indications that the survey methods affected the results. CIBO's critiques are not, therefore, of central relevance to the outcome of the rule.

[1] Section 4(d) of the Administrative Procedure Act (APA), U.S.C. 553(e), states, "Each agency shall give an interested person the right to petition for issuance, amendment or repeal of a rule." Although Section 4(d) of the APA also establishes a right to petition for administrative reconsideration, that provision almost certainly does not apply to petitions for reconsideration of regulations that are promulgated pursuant to the rulemaking provisions of Section 307(d) of the Clean Air Act. See section 307(d)(1)(N), 42 U.S.C. 7607(d)(1)(N). ("The provisions of section 553 through 557 * * * of Title 5 of the United States Code shall not, except as expressly provided in this subsection, apply to action to which this subsection applies.") In any event, the criteria for evaluating a petition for reconsideration under APA are essentially the same as those for section 307(d)(7)(B) petitions. *See* Denial of Petitions to Revise NSPS for Stationary Gas Turbines, 45 FR 81653–54, and decisions cited therein.

C. Summary of SO_2 Reconsideration Petitions

1. CIBO

CIBO argued that (1) the SO_2 standards are inconsistent with the 1977 amendments to the CAA, (2) national energy policy was not considered, (3) EPA erroneously analyzed the results of a "new boiler survey," (4) the "new boiler survey" produced important new information, (5) post-proposal waste disposal information showed that flue gas desulfurization (FGD) on coal-fired units is not cost effective, (6) post-proposal fluidized bed combustion (FBC) and spray dryer information did not show that they constitute "demonstrated technologies, (7) EPA did not provide notice of the extent of its reliance on vendor guarantees, and (8) EPA should have extended its unanticipated exemption from percent reduction requirements for noncontinental areas to the continental United States. CIBO argued that these post-proposal developments compel reconsideration under section 307(d)(7)(B).

This is not the case. The issues of consistency with the 1977 amendments to the CAA and national energy policy were raised and discussed at length prior to proposal as well as during the comment period. [See e.g., "Background Information Document" (BID), Volume 4.] Such comments, therefore, do not compel reconsideration under section 307.

Concerning the analysis of the "new boiler survey," EPA surveyed steam generating unit sales from 1981 to 1984 to determine why new steam generating units are installed, what percentage of recent sales were for replacement, how sales might be related to increased cost, and the impact of new units on overall SO_2 emissions. The survey was conducted to respond to CIBO comments that the great majority of new units replace existing units and that the NSPS would prompt owners to delay purchasing replacement units. CIBO suggested that EPA's analysis of the "new boiler survey" is faulty and argued that had EPA correctly analyzed the survey, the outcome of the rule would have been different.[2]

Again, this is not the case. The findings of the survey indicate that although replacement was the primary reason for many new units, a roughly equal number of units are installed for new applications. The survey also found that the decision to build most of these new application units was not sensitive to cost increases in the range expected to result from the new rules. Findings from the survey also indicated that many existing units would continue to be used alongside the replacement units.

In its petition, CIBO hypothesized that the answers received from the survey might have been different if the survey had asked whether the unit would be built if air pollution control equipment were required. However, CIBO provided no details to support this conjecture. Unsupported conjecture does not provide a basis for reconsideration under section 307. As discussed in greater detail in Section IV below, the amount, not the origin, of costs seems relevant to elasticity of sales as a function of costs. The replacement rate may affect the number of unit sales, but in the final analysis—and absent volume price decreases—the relationship between control costs and absolute emission reductions is more relevant to standard setting.

CIBO also argued that, apart from costs, reliability needs also deter new unit installation if pollution control systems are less reliable than production facilities. On August 19, 1988, it provided EPA with a "supplement" attaching letters attesting to the need for high rates of facility reliability. This argument does not provide a basis for reconsideration under section 307. The general point—the need for high steam generating unit reliability—was raised at the time of proposal and addressed during the comment period [See e.g., BID, Volume 4 (EPA-450/3-87-024)]. The specific argument that this need, like increased costs, could deter new installation could have been made at that time. Factored into the analysis was the cost of backup systems generally used by industry to ensure steam supply. Use of such backup systems should assure reliable operation and should not significantly affect installation rates. Even if backup systems did affect installation rates, the point remains that the number of new units and replacement units is less relevant to standard setting than the relationship between control costs and emissions.

CIBO argued that the "new boiler survey," properly analyzed, supported its claim that EPA overstated emission reductions. For reasons explained in Section IV below, CIBO's argument does not provide information of central relevance to the outcome of the rule compelling reconsideration under section 307. The reasonableness of the rule, considering costs, is not significantly affected by the total number of projected unit installations since smaller population projections would mean a corresponding reduction of control costs. Furthermore, CIBO simply renews a contention that was raised and discussed during the comment period. (See e.g., BID, Volume 4.)

CIBO also argued that a post-proposal memorandum, which was prepared for EPA and discussed the disposal of sodium-scrubbing waste, coupled with EPA's "reliance" on sodium-scrubbing, shows the "impracticability" of the rule—or, rather, that the rule renders "impracticable" the use of coal-fired steam generating units. The post-proposal memorandum notes, among other things, that several sodium scrubbers are located in areas where local rules might limit the availability of some scrubbing waste disposal options (Docket No. A-83-27, Docket Item IV-B-12).

The issue of scrubber waste disposal was raised and thoroughly discussed both prior to proposal and during the comment period. (See e.g., BID, Volume 4.) CIBO's comments on the post-proposal memorandum do not compel reconsideration under section 307. The possibility that some sources may be limited in their disposal options does not change the outcome of the rule.

CIBO also argued that post-proposal memoranda prepared for EPA do not show that fluidized bed combustion (FBC) and lime spray dry scrubbers are "demonstrated" technologies. (See e.g., Docket No. A-83-27, Docket Items IV-B-18 and IV-B-97.) CIBO's critique of the post-proposal memoranda does not compel reconsideration under section 307. The Agency's conclusion that FBC and lime spray dryers are "demonstrated" technologies was explained prior to proposal and again in response to public comments [See e.g., BID, Volume 4; 52 FR 47837; and "Summary of Regulatory Analysis" (EPA-450/3-86-005).] The EPA's conclusion in the final rule, as well as at proposal, was based on the judgment that test data and other factors indicate that high levels of reliability are achievable. The post-proposal memoranda, while providing additional support for this conclusion, were far from its sole support. Critiques of the memoranda, therefore, are not centrally relevant to the finding that these technologies are demonstrated for purposes of Section 111 of The CAA. The merit of CIBO's critiques is discussed in Section IV below.

[2] That EPA was going to conduct the "new boiler survey" was noted in the June 19, 1986, notice of proposed rulemaking (51 FR 22384). Notice of the availability of the study was sent to all commenters in April 1987, informing them that new analyses were being added to Docket A-83-27.

CIBO argued that EPA did not provide notice of the "extent" of its reliance on vendor guarantees with respect to the demonstrated status of lime spray dryers and that EPA improperly relied on a guarantee that was informal and unenforceable. This comment does not constitute centrally relevant new information compelling reconsideration under section 307. As CIBO's comment acknowledges, the possibility that EPA might refer to vendor guarantees was evident during the comment period. (See e.g., "Summary of Regulatory Analysis.") Moreover, as is discussed in Section IV below, EPA's determination that lime spray drying technology is demonstrated was based on engineering review of lime spray dryer designs, test data, and other information that indicate that this technology is demonstrated. The vendor guarantees were merely corroborative of this conclusion.

CIBO argued that the exemption for noncontinental areas from the percent reduction requirement should apply to all areas where natural gas is unavailable. The comment is essentially a moot point. The noncontinental exemption applies in practice only to units firing very low sulfur oil. The final standard, in fact, exempts all sources firing very low sulfur oil from the percent reduction requirement, no matter where they are located.

2. Zimmer Owners

The Zimmer owners argued that information provided in their petition shows that use of 130 ng SO_2/J (0.30 lb SO_2/million Btu) oil is not cost effective relative to using a higher sulfur content oil. This comment does not compel reconsideration under section 307. The original exemption at the time of proposal was based on a heat input limitation of 86 ng SO_2/J (0.20 lb SO_2/ million Btu), and the exemption in the final rule was based on 130 ng SO_2/J (0.30 lb/million Btu). The Zimmer owners' concerns about the cost effectiveness of various low sulfur oils could have been raised during the comment period. The Zimmer owners' comment is discussed in more detail in Section IV below.

3. HECO

The final rule, unlike the proposal, exempted oil-fired units in noncontinental areas from the percent reduction requirement, but limited emissions to the equivalent of 130 ng SO_2/J (0.30 lb. SO_2/million Btu). HECO argued that no notice of the 0.30 requirement was given, that the emissions limit should be raised to 210 ng SO_2/J (0.50 lb SO_2/million Btu) on Oahu, and that no limit should be imposed elsewhere in Hawaii.

This argument does not compel reconsideration under section 307. It is true, as HECO claims, that the emission limit of 130 ng SO_2/J (0.30 lb SO_2/million Btu) was developed after (and as a result of) the comment period. The Agency had, however, established an 86 ng SO_2/J (0.20 lb SO_2/million Btu) limit as the basis for a percent reduction exemption. HECO's objections could have been raised during the comment period because its objections are based on the cost and/or current unavailability of very low sulfur oil, i.e., they apply to both the proposed emission limit and the final emission limit. Further, the standard does not require use of 130 ng SO_2/J (0.30 lb SO_2/million Btu) oil, but rather allows the owner to meet this emission limit by whatever means the owner chooses. HECO's comments are discussed in more detail in Section IV below.

4. API/NFPA

API and NFPA argued that new post-proposal materials and analyses showed that various backup strategies for maintaining compliance during periods of planned and unplanned outages (i.e., start-ups, shutdowns, and malfunctions) are not available.

This comment does not compel reconsideration under Section 307 because the information in the API/ NFPA petition, including information about demand charges and premiums for noninterruptible supplies of natural gas, was addressed in response to comments or could have been presented during the public comment period. Furthermore, as discussed in Section IV below, even upon consideration of the information contained in the petition, EPA finds no basis for reconsideration of the rule.

II. Petitions Submitted Concerning the PM/NO_x Standards

A. Achievability of the PM/NO_x Standards

1. Achievability of NO_x Standards by Distillate Oil-Fired Electric Utility Auxiliary Steam Generating Units

Petitioner's Comment: The Zimmer owners commented that electric utility auxiliary steam generating units that fire distillate oil cannot consistently meet the NO_x standard of 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input.

Agency Response: Electric utility auxiliary steam generating units are large field-erected units. These units are characterized by low volumetric heat release rates, typically below 310,000 J/ sec-m^3 (30,000 Btu/hour ft^3). Heat release rate is one of the major factors in determining the NO_x-generating potential of a unit firing distillate oil and the ability of control techniques to limit NO_x emissions. Data show that NO_x emissions increase as heat release rate increases, all other things being equal. Emission test data available from three distillate oil-fired steam generating units employing staged combustion demonstrate that NO_x emissions can be limited to 43 ng NO_x/J (0.10 lb NO_x/ million Btu) or below through the use of this technique. (See Docket No. A-79-02, Docket Items II-I-224, II-A-9, and II-A-14.) One of the units used a staged combustion burner while the other units used staged combustion air. These steam generators are packaged units with volumetric heat release rates of 460,000 to 490,000 J/sec-m^3 (45,000 to 48,000 Btu/hour-ft^3), which are higher than those typical for electric utility auxiliary units.

Since the heat release rates for electric utility auxiliary units are substantially below those of the tested steam generating units, NO_x emissions can be limited to 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input or less through the use of staged combustion when firing distillate oil. Moreover, other NO_x limitation techniques, such as flue gas recirculation, are available which have been shown to be capable of limiting NO_x emissions to 43 ng NO_x/J (0.10 lb NO_x/million Btu) or less in distillate oil-fired steam generating units with heat release rates up to 640,000 J/ sec-m^3 (62,000 Btu/hour-ft^3). (See Docket No. A-79-02, Docket Items II-I-224 and IV-B-23.) Accordingly, there is no basis for granting the request by the Zimmer owners for a higher NO_x limit.

2. Special Monitoring Problems Associated with Electric Utility Auxiliary Steam Generating Units

Petitioner's Comment: UARG contended that the monitoring requirements in the NO_x standards would be difficult, if not impossible, for very low capacity factor steam generating units to meet. Specifically, the petitioner claimed that facilities such as oil-fired utility auxiliary steam generating units would not be able to satisfy the initial performance test requirement to be completed within 180 days of initial start-up because a unit that operates only 2 or 3 days per month, for example, would take an entire year to satisfy these performance test requirements.

Similarly, the petitioner claimed that the 30-day rolling average compliance test for these same units would not produce meaningful data because it is unlikely that enough data would be collected in 1 year to calculate even one 30-day average.

Agency's Response: The Agency does not agree with the petitioner's contention that the NO_x monitoring requirements cannot be met by very low capacity factor steam generating units. The initial performance test is based on emissions data collected during the first 30 operating days following unit start-up (operation of a unit for a single hour during a given day qualifies as an operating day). Up to 180 calendar days can be used to collect these 30 days of operating data. Many very low capacity factor units may be able to gather 30 days of data through collection of NO_x emissions data in conjunction with commercial acceptance testing of the unit and during normal operating days. If insufficient operating days occur during the first 180 calendar days, the owner can operate the unit and vent steam to collect the additional NO_x emissions data necessary. If collection of such data is considered infeasible for an individual unit, the owner can apply to the Administrator for relief under § 60.8(b) of the General Provisions of 40 CFR Part 60.

The petitioner misunderstands the mechanics of how 30-day rolling averages are calculated in contending that insufficient data would be collected in a year to calculate 30-day averages. A 30-day rolling average is calculated as the average of all daily average data collected during the previous 30 consecutive steam generating unit operating days. The first 30-day average is calculated after initial unit start-up and serves as the initial performance test. Thereafter, a new 30-day rolling-average is calculated at the end of each new steam generating unit operating day.

B. Interrelationship of PM/NO_x and SO_2 Standards

1. Effect of SO_2 Control Techniques on PM/NO_x

Petitioner's Comment: CIBO stated that EPA proposed a stringent (90 percent reduction) SO_2 standard after proposal of the PM/NO_x NSPS, but ignored economic and technical interrelationships between the proposed SO_2 standards and the promulgated PM/NO_x standards. According to the petitioner, all of these combustion products (PM, NO_x, and SO_2) are critically interrelated and, therefore, should not have been considered under two separate NSPS. The petitioner pointed out that implementation of control techniques to satisfy the SO_2 standards will affect the control techniques necessary to satisfy the PM/NO_x standards, both from a technical feasibility and a cost standpoint. The petitioner also stated that no opportunity was given for public comment on the technical or cost impact of the SO_2 standards on the PM/NO_x standards.

Agency Response: Although NSPS for PM/NO_x and SO_2 were developed in separate regulatory actions, potential technical or economic interrelationships were considered throughout the development of regulations for each pollutant and fuel type. For example, because PM and SO_2 emissions and control technologies for oil-fired units are closely interrelated, the PM and SO_2 standards for oil were considered in the same regulatory action. Relationships between the use of a fabric filter or electrostatic precipitator (ESP) to reduce PM emissions and a flue gas desulfurization (FGD) system to reduce SO_2 emissions from coal-fired steam generating units were also identified, but were found to be separable, and were therefore analyzed in separate regulatory actions. Possible interrelationships between NO_x and SO_2 control were also considered, but no significant interrelationships were identified.

Further, when evaluating alternative SO_2 standards for coal-fired units, the Agency assumed that the proposed PM and NO_x standards were already in effect and that new units were constructed and operated to comply with them. This approach ensured that even minor technical and cost interrelationships between the standards for PM, NO_x, and SO_2 were implicitly considered during the course of the SO_2 rulemaking. Accordingly, the petitioner's contention that the Agency did not consider the interrelationship between the PM/NO_x and SO_2 standards is incorrect.

Finally, during the comment period on the proposed SO_2 standards, the public could have commented on technical and economic interrelationships among the PM, NO_x, and SO_2 standards. However, no significant interrelationships were identified by any of the commenters. Furthermore, mere conjuncture is not a basis for granting a petition for reconsideration. Only one specific interrelationship of the standards was identified by the petitioners and, as is explained below, it does not impose unreasonable impacts.

2. Achievability of NO_x Standards by Pulverized Coal-Fired Units When Using Backup Fuel to Meet SO_2 Standards

Petitioners Comment: As a specific example to illustrate the PM/NO_x/SO_2 interrelationship, CIBO cited a field-erected pulverized coal (PC)-fired steam generating unit firing natural gas or oil as a backup fuel. The petitioner stated that firing backup fuels in PC units will become more frequent and prolonged than in the past because of FGD system reliability problems, fuel disruptions, and fuel price variations. According to the petitioner, all PC units are equipped with air preheaters, which typically deliver preheated air at 110 to 160 °C (400 to 600 °F) for combustion of both primary and backup fuels. Such high air temperatures, which increase the formation of thermal NO_x, restrict the ability of units with volumetric heat release rates below 720,000 J/sec-M^3 (70,000 Btu/hour-ft^3) to meet the 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input NSPS for natural gas for distillate oil combustion. Since using backup fuel is part of the basis for the SO_2 standards, the petitioner stated that this requirement must be considered in the NO_x standards and the necessary relief must be provided in the form of a higher NO_x emission rate for PC units firing natural gas or distillate oil with air preheat.

Agency Response: Coal-fired steam generating units inherently have larger furnace volumes than oil- and natural gas-fired units with equivalent steam generating capacities. Because of the lower heat release rates in these larger furnace volumes, conversion of atmospheric nitrogen to NO_x while firing backup fuels in a field-erected PC-fired steam generating unit is lower than in a smaller, higher heat release rate steam generating unit designed to fire natural gas or oil. To assure that proper combustion conditions are achieved to minimize NO_x formation, a number of NO_x reduction techniques are available. These techniques include reducing combustion air temperature by either total or partial bypass of the air preheater, and using flue gas recirculation, overfire air ports, and low NO_x burners to fire backup fuels. Data from units employing staged combustion burner (SCB) or staged combustion air technology indicate that these controls can meet the 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input limit when firing natural gas or oil in units with heat release rates below 720,000 J/sec-m^3 (70,000 Btu/hour-ft^3). In addition, one low NO_x burner manufacturer stated that NO_x emissions can be limited to 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input while firing natural gas if the unit heat release rate is less than 770,000 J/sec-m^3 (75,000 Btu/hour-ft^3). (See Docket No. A-79-02, Docket Item IV-E-14.)

Industrial field-erected units have heat release rates well below these levels. A survey of such units installed between 1982 and 1986 identified nine PC-fired units. (See Docket No. A-83-27, Docket Items IV-J-4, IV-J-5, IV-J-7, and IV-J-9, and IV-J-42.) The heat release rates for these units ranged from 140,000 to 245,000 J/sec-m^3 (13,500 to 23,700 Btu/hour-ft^3). Since these heat release rates are substantially below the upper limits of 720,000 to 770,000 J/sec-m^3 (70,000 to 75,000 Btu/hour-ft^3) identified above, NO_x emissions can be reduced to 43 ng NO_x/J (0.10 lb NO_x/million Btu) heat input or less through use of the above NO_x reduction techniques when firing natural gas or oil as a backup fuel. Accordingly, there is no basis for granting the CIBO request for a higher NO_x limit or convening a proceeding to reconsider the interrelationship between the PM/NO_x and SO_2 standards.

C. Projected Environmental and Economic Impacts

1. Overstatement of Impacts

Petitioner's Comment: EPA projected that 725 new steam generating units with heat input over 29 MW (100 million Btu) would be built in the 5-year period following proposal. CIBO stated that this number is too high (CIBO contended that 250 new units are more likely, of which 80 percent are replacement units) and, as a result, the projected economic, environmental, and energy impacts associated with the PM/NO_x standards are overstated. The petitioner cited the Agency's own "new boiler survey" to support its contention. The petitioner contended that the survey shows that the number of "new" steam generating units as opposed to "replacement" units was overestimated, that purchase of replacement units is discretionary, and that the impact of the standards will be to further reduce the number of replacement units during the period modeled, given the high cost of complying with the standards. Thus, CIBO argued that the projected emission reductions achieved by the standards are significantly overestimated.

Agency's Response: As explained in the response to comments in the SO_2 rulemaking (see e.g., 52 FR 47826), several factors suggest that 1984 estimates of steam generating unit population and total "new" emissions were high. These estimates of new steam generating units were based on U.S. Department of Energy projections made in the late 1970's. (See e.g., BID, Volume 4.) As the Agency explained, however, any change in the overall balance between the costs and benefits and, hence the reasonableness of the standard, depends on the relative change in both costs and benefits. If EPA has overestimated the number of new units subject to the standard, then *both* the costs as well as the emission reductions (i.e., benefits) of the standard decrease. EPA's conclusion as to the standard would remain valid even if CIBO's estimates, or lower ones, proved more accurate.

The total number of new steam generating units and the percentage of these units that are replacements was examined in the "new boiler survey." The survey results suggest that about half of all unit installations from 1981 to 1984 represented replacements of existing units. However, for four reasons, the fact that a significant number of new units are replacements for existing units does not support CIBO's claims that lower-than-projected emissions reduction compel reconsideration. First, replacement capacity may simply displace existing capacity in an accounting sense, but it represents *new* capacity under section 111 of the Clean Air Act. Therefore, the petitioner's exclusion of replacement capacity from its calculations of baseline emissions increases is not warranted. Second, the suggestion that replacement should not be counted because it is discretionary and might be deferred is unfounded. Deferring replacement is simply replacement displaced in time to a later date. Third, the "new boiler survey" results indicate that the decision to install new steam generating units is not significantly cost sensitive in the range of cost increases anticipated by the Agency. Fourth, with respect to projected post-NSPS emission levels, many of the replaced units are not retired but continue in service.

2. Legal Basis for and Economic Impacts of Controls on Electric Utility Auxiliary Steam Generating Units

Petitioner's Comment: In their petitions, UARG and the Zimmer owners argued that Subpart Db should not apply to auxiliary utility steam generating units that are used to assist in start-up and shutdown of the main steam generating unit because these units are not significant contributors, operate at very low capacity factors, use oil or natural gas, operate intermittently, and are located in rural areas. The petitioners also contended that any standards for PM/NO_x would result in excessive cost impacts on electric utility auxiliary steam generating units relative to units operated at higher capacity factors. According to the petitioners, the standards would also have minimal impact on reducing PM and NO_x emissions beyond those achieved by current unit designs. Therefore, the petitioners recommended that the final standards be amended to either (1) exempt utility auxiliary steam generating units from the standards; (2) adopt a capacity factor cut-off for the promulgated standards and establish different levels of control for units that operate at very low annual capacity factor levels, such as 10 percent or less; or (3) reduce the burden imposed by NO_x monitoring requirements on steam generating units that operate at very low annual capacity factors.[3]

Agency Response: As the Agency stated in its June 19, 1984, proposed rule (49 FR 25156), all steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour) (other than those units subject to Subpart Da) were included within the Subpart Db rule (51 FR 42794). The Agency included very low capacity factor units on the basis that the design of these units and control technologies for emission reductions are similar, irrespective of capacity factor. As was noted in the final rule, "there is no requirement that each subcategory of a listed category or each individual source within a listed category also be a significant contributor." (See 51 FR 42795; *see also* 51 FR 42772.) It was thereby determined that auxiliary utility steam generating units are subject to Subpart Db.

The Agency does not agree that the criteria set forth by UARG and the Zimmer owners provide a basis for EPA to subcategorize utility auxiliary steam generating units. No doubt there are multiple bases upon which Subpart Db steam generating units could be subcategorized. Criteria such as ownership and/or the existence of companion base load units (i.e., units owned by utilities, or units auxiliary to base load units) do not seem to be functionally useful. An exemption for rural settings is inconsistent with the concept of section 111, which contemplates national standards and does not distinguish among regions based on air quality achieved. Capacity factor, although related to the level of emissions, is unsuitable as a basis for exemption from all standards where emission control remains cost effective; as the final rule recognizes, however,

[3] The Zimmer owners also contended that section 111(f) bars EPA from determining that utility auxiliary steam generating units are within the category of units subject to Subpart Db and, simultaneously, in regulating such units, section 111(f) requires that EPA establish a list of major stationary source categories and establish deadlines for regulation. The Zimmer owners do not explain their interpretation of section 111(f). On its face, section 111(f) contains no such bar.

capacity factor is an appropriate criterion for exemption where emission control is not cost effective.

As discussed in a separate rulemaking notice published today elsewhere in the **Federal Register**, the Administrator, under his discretionary authority, is proposing to amend the NO_x performance testing and monitoring requirements for steam generating units that operate at very low annual capacity factors (less than 10 percent) and that fire natural gas, distillate oil, or low nitrogen residual oil (either alone or in combination). The proposed rule imposes less burdensome performance testing and monitoring requirements on large steam generating units and exempts small steam generating units from the NO_x standards.

The Agency also does not agree that auxiliary utility steam generating units should be exempted from the performance standards for PM and NO_x on the basis that minimal emission reductions will be achieved. Although most auxiliary utility units may be designed to fire oils with PM emission potentials of less than 43 ng/J (0.10 lb/million Btu) and may be equipped with low NO_x burners, the performance standards provide a "cap" to assure that these units are operated in a manner that minimizes emissions. Establishment of performance standards as a "cap" to limit future emissions is a valid exercise of regulatory authority.

D. "New Boiler Survey"

Consideration of New Information Gathered in the "New Boiler Survey."

Petitioner's Comments: CIBO stated that EPA recognized the importance of steam generating unit replacement when it announced that it had initiated a "new boiler survey" to gather information regarding the impact of the NSPS on new steam generating unit construction and refurbishment (51 FR 16586). The petitioner contended that many new steam generating units are replacements for existing units and, in most cases, these new units represent discretionary expenditures by unit owners. As a result, if the cost of a new unit is too high, the owner will continue to use the existing unit. Because existing units frequently have higher emission rates than new units, failure to install new units will result in higher emission levels and fewer reductions than claimed by the Agency. The petitioner contended that EPA should recalculate the net reduction in emissions from steam generating unit replacement in its analysis and modify the final rule to encourage economic replacement of higher emitting, existing units.

Agency Reponse: Two questions are relevant here: First, what is the impact of the PM/NO_x standards on the rate of steam generating unit installations; and second, what are the implications of the "new boiler survey" for the PM/NO_x rule. Regarding the first of these questions, the "new boiler survey" was conducted in response to public comments on the proposed SO_2 standards. It focused on collecting data about the reasons new units are installed, the extent to which new units may be replacements for existing units, and the impact of new units on overall SO_2 emisssions. The survey did not directly examine PM/NO_x emissions. However, based on the survey data and earlier analyses of the cost of PM and NO_x control techniques, the impact of the PM/NO_x standards on replacement of existing steam generating units is considered minimal because of the small cost of the PM/NO_x standards on new units.

As to the second question, EPA's analysis of the "new boiler survey" results confirms the need for PM/NO_x controls. It may well be true, as the petitioner contends, that PM and NO_x emission rates for individual new units will be lower, even absent an NSPS, than for existing units of equal size and fuel use patterns. However, the level of reductions from individual units that would occur in the absence of an NSPS is less than the emission reductions resulting from the promulgated standards.

The argument that NSPS-induced delays in steam generating unit replacement will result in higher aggregate emissions is not supported by analysis. (See Docket A-83-27, Docket Item IV-A-4.) Based on unit replacement data from the "new boiler survey" and the PM and NO_x emission levels expected from existing and NSPS-controlled new steam generating units, aggregate emissions from existing and new steam generating units at facilities covered by the survey will increase after installation of new units even with the NSPS. For PM, the aggregate increase was roughly 30 percent relative to the level occurring prior to new unit installation. For NO_x, the aggregate emissions almost doubled. This result—higher aggregate emission despite lower emission rates from individual units—is caused primarily by emission increases from new units installed for new applications that substantially exceed the emission reductions from facilities where replacements occurred. Adoption of less stringent emission control requirements for new units would result in even greater increases in aggregate PM and NO_x emissions. As a result, promulgation of an NSPS with stringent emission limits is essential if aggregate emissions of PM and NO_x are to be minimized.

E. IFCAM National Impacts Model

Validity of the Model

Petitioner's Comment: CIBO claimed that the Industrial Fuel Choice Analysis Model (IFCAM) EPA used to forecast industrial steam generating unit sales has serious shortcomings. The model is based on historical data from a period of chaotic energy prices and large cost differentials between high cost fuels (such as natural gas and fuel oil) and low cost fuels (such as coal and waste fuels). The petitioner stated that the previous behavior of steam generating unit owners in conserving energy and switching fuels would not be repeated today because of the large decline of natural gas and fuel oil prices relative to those for coal and waste fuels. According to the petitioner, the IFCAM model must be revalidated using the steam generating unit sales results contained in the "new boiler survey" and energy prices for the period in question, allowing for appropriate decision lead times. The petitioner stated that the IFCAM model should not be used for regulatory analyses until this revalidation has been accomplished. If the IFCAM projections cannot be validated, the petitioner stated that they must be disregarded and new data developed.

Agency Reponse: The petitioner appears to misunderstand the design and operation of IFCAM. IFCAM is simply a "least cost" economic choice model designed to aid in examining the impact of alternate regulatory standards on new industrial steam generating units. Key economic parameters (such as the estimated growth in national industrial energy demand and projected prices for coal, oil, and natural gas) are inputs to the model and reflect projected economic conditions in the future. For each alternate regulatory standard, IFCAM uses the projected fuel prices and total industrial energy demand to evaluate steam production costs for new industrial units spanning a range of sizes, capacity factors, and fuels, and then selects the steam generating unit and fuel combination with the lowest after-tax costs over the useful life of each unit. The results of these fuel choice selections for each new steam generating unit are then added together to estimate the total costs, emissions, and fuel use associated with the alternate regulatory standard.

Consequently, the impacts of alternate regulatory standards are projected by IFCAM based on the input values for projected fuel prices, projected industrial energy demand, and specified regulatory requirements. The results obtained from IFCAM, therefore, are not based on the "past," but are based on projections of the "future."

III. Petitions Submitted Concerning the SO_2 Standards

A. Legal Basis for Establishing the SO_2 Standards

1. Consistency of the SO_2 Standards with Congressional Intent

Petitioner's Comment: CIBO supplemented its petition for reconsideration with contentions that the SO_2 standard is inconsistent with Congressional intent in enacting the 1977 amendments to the CAA. The essence of CIBO's contentions is that Congress enacted the section 111 percent reduction requirement to ensure that new sources do not switch to natural gas to avoid the application of control technology. CIBO contends, however, that the percent reduction requirement included in the SO_2 standard will encourage new sources to switch from coal to natural gas. The result, therefore, is to circumvent the statute. (The Department of Commerce also submitted comments on this point.)

Agency Reponse: The petitioner's contentions that the SO_2 standard is inconsistent with Congressional intent are without merit. The petitioner misinterprets section 111. Followed to their logical conclusions, these contentions mean that the Agency should have either not adopted any percent reduction requirement at all, or adopted a percent reduction requirement that applied to all fuels (e.g., coal, oil, natural gas, wood, etc.).

An SO_2 standard for fossil fuel-fired stationary sources without any percent reduction requirement is inconsistent with the explicit language of Section 111 as it was amended by Congress [see CAA 111(a), H.R. Rep. No. 95-294 95th Cong., 1st Sess. 188 (1977) "Conference Report" reprinted in "Legislative History of the Clean Air Act Amendments of 1977", Volume 4, at 2655 "Legislative History"]. If the Agency had adopted an SO_2 standard including only a mass emission limit, sources could have avoided the application of any control technology simply by burning oil or low sulfur coal.

An SO_2 standard with a percent reduction requirement applied to all fuels, including fuels such as natural gas, very low sulfur oil, wood, etc., may also be inconsistent with the explicit language of section 111, which requires the Agency to consider costs. If the Agency had adopted an SO_2 standard applying the percent reduction requirement to all fuels, unreasonably high costs would have been imposed on a number of new sources firing fuels such as natural gas, very low sulfur oil, wood, etc.

EPA reads the percent reduction requirement in section 111 as tempered by the requirement that technology be the "best technological system of continuous emission reduction which (taking into consideration the cost * * *) * * * has been adequately demonstrated." Thus, a percent reduction requirement need not be applied to certain types or classes of sources if the impacts associated with imposing this requirement would be unreasonable. Consequently, the Agency made a thorough analysis of the potential impacts of imposing the percent reduction requirement on various types and classes of sources. Based on this analysis, the Agency included exemptions from the percent reduction requirement where the impacts of imposing this requirement would have been unreasonable. The final SO_2 standard, therefore, is reasonable and this approach represents a reasonable way to harmonize the twin requirements of Section 111 to include percent reduction requirements and to consider costs.

Finally, even in the absence of the SO_2 standard, economic factors unrelated to the standards, such as the relative price between coal, oil, and natural gas, are likely to have more impact on the choice of fuel for a new industrial-commercial-institutional steam generating unit than the SO_2 standard.

2. Impacts of the SO_2 Standard on the Natural Energy Policy

Petitioner's Comment: CIBO claimed that the SO_2 standard is inconsistent with national energy policy in that it fails to encourage the use of coal, threatens a balanced energy supply, and reduces the incentive for companies to develop clean coal technologies. (The Department of Energy and the Department of Commerce also submitted comments on this point.)

Agency Response: The petitioner's comments are a repetition of comments submitted to the Agency during the public comment period following proposal of the SO_2 standards. At worst, as discussed in the "Summary of Regulatory Analysis," the proposal notice (51 FR 22384), Volume 4 of the Background Information Document, and the promulgation notice (52 FR 47826), the SO_2 standard will have only a very small impact on the overall mix of fuels consumed to satisfy national energy demands. Thus, the standard will not cause a significant change in national energy supplies nor will it threaten national energy security.

To illustrate this fact, under the worst case scenario examined by the Agency, about 600 new coal-, oil- or gas-fired industrial-commercial-institutional steam generating units are projected to be sold over the 5-year period between 1986 and 1990. These new units will result in total fuel consumption of roughly 550 PJ/year (520 trillion Btu/year) in 1990. Even if all this energy consumption were satisfied by coal, it would represent less than 3 percent of total United States coal consumption in 1986. Similarly, if all this energy consumption were satisfied by oil or natural gas, it would represent less than 2 percent or 3 percent, respectively, of total oil or natural gas consumption in 1986.

Not all this increased energy consumption in new industrial-commercial-institutional steam generating units, of course, will be satisfied by a single fuel, such as natural gas or oil. Furthermore, the Agency's projections of sales of new steam generating units are quite likely to be overestimated, as the petitioner has pointed out. Consequently, the impact of the SO_2 standard on changes in the national energy mix of coal, oil, and natural gas will be even less significant than these figures might indicate.

The Agency acknowledges that some fuel switching to natural gas may occur as a result of the SO_2 standard. As discussed in Volume 4 of the Background Information Document and the promulgation notice (52 FR 47826), this fuel switching, however, will be small compared to the amount of fuel switching that is likely to occur as a result of the current low price of natural gas. The impact of the SO_2 standard on the difference in cost between firing coal or firing natural gas in a new steam generating unit is small compared to the impact of current natural gas prices. Even in the absence of the SO_2 standard, with current low natural gas prices few new steam generating units are likely to select coal over natural gas.

Finally, as also discussed in the proposal notice (51 FR 22384), Volume 4 of the Background Information Document, and the promulgation notice, (52 FR 47826), in developing the SO_2 standard the Agency recognized that the standard and, in particular, the requirement to achieve a 90 percent reduction in SO_2 emissions, could hinder the development of some new clean coal technologies. The potential risk of failure that might be associated with using a new technology to achieve such a high percent reduction requirement could be sufficient in some cases to deter the use of that technology. Yet it is only through new technologies that better and less expensive means of controlling SO_2 emissions can be developed.

Although development of new technologies should be encouraged, it is not reasonable to permit the use of new technologies if use of these technologies would lead to SO_2 emissions grossly out of balance with what emissions would have been if a conventional technology had been used. Thus, to encourage the development of new technologies that show promise of achieving levels of performance comparable to those of existing technologies, but ensure that SO_2 emissions are not grossly out of balance with what they would have been if a conventional technology had been used, provisions were included in the SO_2 standard that require a 50 percent reduction in SO_2 emissions from new technologies and limit SO_2 emissions to 260 ng SO_2/J (0.6 lb SO_2/million Btu). This percent reduction requirement is low enough to substantially reduce the risk of failure associated with achieving it, and the 260 ng SO_2/J (0.6 lb SO_2 million Btu) emission limit ensures that SO_2 emissions from a source using a new technology will not be grossly out of balance with what SO_2 emissions would have been if a conventional technology had been used.

B. Projected Economic Impacts

1. Cost Effectiveness of a 130 ng SO_2/J (0.30 lb SO_2/million Btu) Heat Input Emission Limit on Electric Utility Auxiliary Steam Generating Units at the Zimmer Owners' Generating Station

Petitioner's Comment: The Zimmer owners stated that EPA did not consider the full costs associated with meeting a 130 ng SO_2/J (0.30 lb SO_2/million Btu) heat input emission limit for its two very low capacity factor auxiliary utility steam generating units. The petitioner stated that the exemption from the percent reduction requirement for oil-fired units with a maximum annual heat input capacity of 30 percent and less was meaningless when their very low capacity auxiliary units must also meet the 130 ng SO_2/J (0.30 lb SO_2/million Btu) heat input emission limit.

The petitioner contended that the full costs of meeting a 130 ng SO_2/J (0.30 lb SO_2/million Btu) heat input standard at its two auxiliary units are grossly disproportionate to the benefits achieved [i.e., Mg (tons) of SO_2 removed]. For these units, either very low sulfur oil must be burned in both the main unit and the auxiliary units or a separate oil handling system must be installed for the auxiliary units. According to the petitioner, the separate handling system would cost a total of $225,000/year, or $13,000/Mg ($11,800/ton) of SO_2 removed, whereas burning very low sulfur oil in both the main unit and auxiliary units would cost a total of $190,000/year, or $11,000/Mg ($10,000/ton) of SO_2 removed. As a result of these unreasonable cost impacts, the petitioner recommended that very low capacity factor auxiliary units be excluded altogether from regulation under Subpart Db standards.

Agency Response: The 130 ng SO_2/J (0.30 lb SO_2/million Btu) heat input emission limit for steam generating units exempt from the percent reduction requirement was established based on an assessment of the emissions and costs of very low sulfur oils. In establishing an NSPS, the Agency determines the best technology available, considering costs and other factors, for the category of sources affected by the standard. This approach does not mean that every source affected by the standards will incur the same costs of compliance. Some individual facilities subject to the standards may experience higher cost. In other words, in setting standards for new sources the Agency takes costs into account for the category of sources considered as a whole, not cost for every particular facility that might be affected.

Nevertheless, EPA reexamined the cost effectiveness of the promulgated SO_2 standard based on the Zimmer owners' specific situation and concluded that even in their situation the costs are reasonable.

Of the two compliance alternatives identified by the Zimmer owners, the lower cost alternative is to use very low sulfur oil in both the main steam generating unit [which is permitted to fire oil with an emission potential of 240 ng SO_2/J (0.55 lb SO_2/million Btu)] and the auxiliary units, which are subject to these standards. Based on the projected emission reductions from only the auxiliary units [estimated at 17 Mg/year (19 tons/year)], the petitioner estimated that the cost effectiveness of SO_2 reductions would be $11,000/Mg ($10,000/ton). However, it is inappropriate to exclude the emission benefits of using very low sulfur oil in the main units. When these emission reductions are included, the cost-effectiveness level is roughly $3,700/Mg ($3,400/ton) of SO_2, which is considered reasonable.

Further, these calculations are based on a fuel premium that the Zimmer owners believe may exist between 130 and 240 ng SO_2/J (0.30 and 0.55 lb SO_2/million Btu) oil of six cents per gallon. Based on a review of available data on fuel sulfur price premiums in the areas surrounding the Zimmer station, this premium appears overstated. In fact, this review identified little, if any, premium in the price between 130 and 240 ng SO_2/J (0.30 and 0.55 lb SO_2/million Btu) oils. As a result, the actual cost-effectiveness level could be considerably lower than the value calculated above.

2. Exemption for Noncontinental Areas

Petitioner's Comment: CIBO contended that the exemption of industrial steam generating units from the 90 percent SO_2 reduction requirement in noncontinental areas was arbitrary. According to the petitioner, the Agency provided this limited exemption due to the unavailability of natural gas in noncontinental areas. The petitioner argued that the distinction between facilities in continental and noncontinental areas is not supportable, considering that steam generating unit owners in some areas of the continental United States also have difficulties in obtaining natural gas.

Agency Response: The petitioner's contention is a moot point. Little or no coal is burned in steam generating units loaded in noncontinental areas. Thus, the exemption for noncontinental areas in the final rule applies in practice only to steam generating units burning very low sulfur oil. The final standard, however, also exempts all steam generating units firing very low sulfur oil from the percent reduction requirement no matter where they are located. In effect, therefore, the exemption sought by CIBO has already been granted in the existing rule. To extend this exemption for oil-fired units to coal-fired units in the continental United States, would present statutory difficulties. Congress plainly intended that the Agency utilize percentage reduction standards where appropriate given other statutory constraints, including the obligation to consider costs and other environmental impacts.

3. Failure to Analyze Economic Impacts on the Paper Industry

Petitioner's Comment: API/NFPA stated that, when compared to the seven other major steam-using industry groups examined in the "Summary of Regulatory Analysis," the paper industry ranked first in industrial steam generating unit fossil fuel consumption. However, EPA performed economic impact analyses for only six of these industries, omitting an analysis of the paper industry. According to the petitioner, such an analysis of the paper industry would have revealed important information about the impact of the standard on the paper industry.

Agency Response: The economic impacts analysis of NSPS for industrial steam generating units was conducted in two phases. The first phase focused on major steam-using industries. Using aggregate economic criteria to characterize each industry selected for analysis, this phase of the analysis examined the potential impact of NSPS on industry average steam costs and product prices, and the ability of the industry to pass increased costs forward to the consumer or to absorb increased costs due to high profitability.

The second phase of the analysis focused on selected industries considered likely to experience the most severe economic impacts. Industries were selected for this phase of the analysis based on several crtieria: (1) Results from the first phase of the analysis indicated further analysis was appropriate; (2) manufacturing operations within an industry were considered unusually steam-intensive; or (3) the steam generating unit capacity within an industry was characterized by unusually low utilization factors. Using model plants and model firms representative of those found within each industry selected for analysis, this phase of the analysis examined the potential impacts of NSPS on product prices and profitability at the plant level and capital availability at the firm level.

The pulp and paper industry was one of the industries examined in the first phase of this analysis. The results, however, indicated that the potential impacts of NSPS on this industry were small and that further analysis of this industry was not warranted in the second phase of this analysis. Although a major steam consuming industry, most of the steam used in the pulp and paper industry for pulping, bleaching, and paper making is generated by burning fuels, such as black liquor and wood, which are not subject to the SO_2 standards. Combustion of oil and coal in the pulp and paper industry may contribute less than one-third of the total steam requirements for this industry. Therefore, the potential impact of the NSPS on steam costs and product prices is small.

In addition, the first phase of the analysis also indicated that the pulp and paper industry was quite profitable. Pulp, paper, and board were produced at record levels in 1984, 1985, and 1986. The rates of after-tax profit on stockholders equity, the rates of after-tax profit on total assets, and the after-tax profits per dollar of sales were near or exceeded the average for all manufacturing plants in 1984, 1985, and 1986.

As a result, the pulp and paper industry was not considered one of those industries likely to experience the most severe economic impacts and, therefore, this industry was not examined in the second phase of the analysis. In any case, the petitioner gave no indication of how such an analysis would change the outcome of the standard. Consequently, the Agency finds no basis for reconsidering the standards.

4. Inadequate Analysis of the Economic Impact of Start-Up, Shutdown, and Malfunction Provisions

Petitioner's Comment: API/NFPS also contended that start-up, shutdown, and malfunction provisions are needed for the standards because methods of compliance with the standards during these periods are not always available or are too expensive for many new paper industry facilities. The petitioner contended that EPA had abandoned its earlier position that emissions during periods of start-up, shutdown, or malfunction would be minimized by relying on spare capacity. The petitioner added that the Agency now relies on the ability of units to switch to very low sulfur oil or natural gas during such periods.

The petitioner stated that many paper mills cannot obtain natural gas and that 0.3 weight percent sulfur oil is not readily available in many areas of the country, particularly in noncoastal areas. The petitioner contended that the lack of natural gas in the noncontinental United States was specifically recognized in the regulations by providing an exemption from the percent reduction requirement for facilities in these locations, but that the regulations discriminate for no valid reason against continental facilities that cannot obtain gas or very low sulfur fuel.

According to the petitioner, many paper mills with access to natural gas would also incur costs for backup supplies of natural gas in excess of EPA assumptions because the gas costs that were assumed when developing the regulations did not take into account demand charges and premium prices for firm gas supplies. Many paper mills would also incur excessive costs for backup supplies of very low sulfur fuel oil. The petitioner estimated that the cost effectiveness of SO_2 removal when using noninterruptible natural gas or very low sulfur oil as a malfunction backup fuel can be as high as $17,300/Mg ($15,700/ton), a ratio almost ten times more than estimated when developing the regulations.

Agency Response: The decision to limit SO_2 emissions during periods of start-up, shutdown, and malfunction was based on the availability of several cost-effective alternatives that an affected facility can use during these periods. Contrary to the petitioner's assertion, using spare FGD capacity was not abandoned as a backup alternative and is the most economically attractive option in many situations. It is true that natural gas is not available everywhere. Similarly, very low sulfur residual oil may be difficult to obtain in noncoastal locations, although very low sulfur distillate oil is generally available throughout the United States. If neither of these fuels is available at a specific location, alternatives such as liquid petroleum gas (LPG) or spare FGD modules could be considered. Each alternative need not be available at every potential location of a new facility.

The costs of spare FGD capacity, natural gas, and very low sulfur oil were analyzed prior to promulgation of the standards. These costs were reexamined based on the petitioner's comments. In addition, use of LPG was also examined. When demand charges cited by the petitioner of $6.60 to $11.40/trillion J/day/month ($7 to $12/million Btu/day/month) are assumed for noninterruptible natural gas, the cost effectiveness of this option ranges from $3,800 to $11,500/Mg ($3,500 and $10,500/ton). The cost effectiveness of all of the other options, however, such as natural gas (which does not carry such high demand charges), very low sulfur oil, LPG, or spare FGD capacity, remains in the range of $550 to $4,400/Mg ($500 to $4,000/ton) of SO_2 removed and is considered reasonable.

In addition, most steam using plants operate several steam generating units at less than full capacity so that if one unit malfunctions, the load can be switched from one unit to another. According to data collected in the "new boiler survey," over 90 percent (i.e., 85 out of 92) of the new coal- or oil-fired units sold between 1981 and 1984 were installed at plants with multiple steam generating units. Because of the availability of backup steam generating capacity, most plants should be able to shift steam production to another unit during periods of FGD malfunction.

In view of this variety of start-up, shutdown, and malfunction compliance options, individual plants will be able to economically control SO_2 emissions during these periods.

5. Legal Requirement for Consideration of Start-up, Shutdown, and Malfunction Costs

Petitioner's Comment: API/NFPA further contended that the courts require consideration of start-up, shutdown, and malfunction costs, citing *National Lime Association v. EPA,* 627 F.2d 416 (DC Circuit 1980) (referred to hereinafter as *National Lime*). According to the petitioner, the costs of complying with the standards during periods of start-up, shutdown, and malfunction are unreasonably high and could be avoided with a provision for a temporary variance during start-up, shutdown, and malfunction conditions.

Agency Response: National Lime does not require special start-up, shutdown, or malfunction provisions. Rather than specifying a particular requirement or type of analysis to be undertaken, the court in *National Lime* required only that consideration be given to the achievability of the standards under the anticipated range of operating variables. The petitioner correctly pointed out that analysis of the achievability of standards under the likely range of conditions should include an assessment of the cost of compliance associated with start-up, shutdown, and malfunction of FGD equipment. As discussed above, the costs of several different start-up, shutdown, and malfunction alternatives were analyzed. The results of this analysis indicate that the impacts associated with limiting emissions during start-up, shutdown, and malfunction are reasonable. Thus, it is clear that the Agency's analysis in adopting the standards is consistent with *National Lime.*

6. Availability of 130 ng SO_2/J (0.30 lb SO_2/million Btu) Oil in Hawaii [4]

Petitioner's Comment: HECO stated that the unique fuel supply and electric generation situation in Hawaii was not considered in establishing the 130 ng SO_2/J (0.30 lb SO_2/million Btu) emission limit. HECO contended that EPA should broaden the exemption to allow sources on Oahu to burn oil with a sulfur content of 0.5 weight percent or less, which HECO currently is required by local regulations to fire on Oahu.

The two refineries located on the island of Oahu purchase crude oils with low sulfur contents that, when blended, produce low sulfur residual oil with 0.5 weight percent sulfur or less. These refineries cannot supply all of HECO's needs, however, and approximately 3 million barrels of low sulfur residual oil are imported by HECO from the West Coast of the United States, Singapore, and other worldwide sources.

Meeting a sulfur specification of 0.5 weight percent permits HECO and the two refineries on Oahu to keep costs down and allows HECO to purchase low sulfur residual oil that is competitive with low sulfur residual oil in the continental United States. Having to purchase low sulfur residual oil with a sulfur content of less than 0.3 weight percent would increase HECO's costs. Besides the premium for this oil, there would be additional costs for segregated storage, and the benefits would not be worth the costs. As a result, the promulgated standards would effectively preclude new Subpart Db steam generating units on Oahu.

Agency Response: HECO argues, in effect, that the exemption from the 90 percent reduction requirement included in the final standard for steam, generating units firing very low sulfur oil should be increased from 130 ng SO_2/J (0.30 lb SO_2/million Btu) to 240 ng SO_2/J (0.50 lb/million Btu) since firing oil containing less than 130 ng SO_2/J (0.30 lb SO_2/million Btu) will increase HECO's costs. The mere fact that complying with this exemption from the percent reduction requirement will itself result in some increase in costs, if HECO decides to take advantage of the exemption, is not a sufficient basis for reconsidering the exemption. This exemption was not included in the standard to provide a convenient means for sources to avoid the percent reduction requirement or for sources to avoid experiencing any increase in costs in complying with the standard.

The exemption from the percent reduction requirement included in the standard for steam generating units firing oils of less than 130 ng SO_2/J (0.30 lb SO_2/million Btu) was based on a broad weighing of the relative costs and benefits of percent reduction requirements compared to firing oils of various sulfur contents. The costs of complying with the standard will vary somewhat from location to location, and at any specific location will depend on factors, such as local fuel prices, which are unique to that location. Not every steam generating unit, therefore, will find it advantageous to comply with the standard in exactly the same way. Some units may find it advantageous to comply with the standard by meeting the percent reduction requirement, others may find it advantageous to comply with the standard by firing very low sulfur oils. In short, not every steam generating unit subject to the standard will experience the same costs, nor is there any requirement in section 111 of the CAA that the Agency tailor the standard in such a way that no source will experience higher costs than any other source.

In the original rulemaking, the Agency examined a broad range of costs associated with the standard. (See e.g., "Summary of Regulatory Analysis.") HECO's contention that it will experience increased costs, or for that matter even that it may experience higher than average costs, in complying with the standard (or exemptions from the standard) would not have changed the outcome of the rule and, therefore, does not compel reconsideration.

Despite this finding, however, the Agency is unaware of why any HECO facility would be unable to take advantage of the exemption from the percent reduction requirement for steam generating units firing oils of less than 130 ng SO_2/J (0.30 lb SO_2/million Btu) if it chose to, nor does HECO suggest otherwise.

First, Hawaii's access to very low sulfur oil may well be equal to or superior to that of many areas of the continental United States, with its access to waterborne shipments of very low sulfur fuel oils from Indonesia and California, two of the largest markets of very low sulfur residual oil in the world.

Second, available data from the U.S. Department of Energy (DOE) for the years 1985 and 1986 (Docket No. A-83-27, Docket Items IV-I-3, IV-I-5, IV-I-6 and IV-I-7) indicate that about 10 to 20 percent of the residual oil used by HECO in 1985 and 1986 was 0.3 weight percent sulfur (or less) with the balance being between 0.3 and 0.5 weight

[4] Following the submittal of its Petition for Reconsideration in March, HECO offered to provide additional information concerning oil shipments and oil consumption on the Hawaiian Islands to support its contention that oil containing less than 0.3 weight percent sulfur was unavailable in Hawaii. No such data were forthcoming until December 19, 1988, some 9 months after submittal of the Petition for Reconsideration. The data covered the 1984-1987 time period, and much of this information could have been submitted during the comment period following proposal of the rule in June 1986, and certainly the information could have been submitted with the Petition for Reconsideration. HECO never advised the Agency that it was having difficulty obtaining the data or that it actually intended to supplement its petition. The Agency has no obligation to delay action on the Petitions for Reconsideration pending submittal, however belated, of information from petitioners or others. Nevertheless, the responses set forth below do address information presented in HECO's December 19, 1988, submittal.

percent sulfur. Additional data indicate a significant percentage of the residual oil imported into Hawaii (i.e., from outside the United States) was less than 0.3 weight percent sulfur: 7 percent in 1985; 15 percent in 1986; and 85 percent in 1987.

Furthermore, as HECO points out in its supplement, it currently imports oil from the West Coast of the United States and Singapore. Based on review of DOE data for 1987 (Docket A-83-27, Docket Item VI-B-9), supplies of residual oil containing less than 0.3 weight percent sulfur are currently available in California. These residual oils are refined from Indonesian and Australian crude oils and could be shipped to Hawaii. Handling requirements for these 0.3 weight percent sulfur residual oils are similar to those for higher sulfur content residual oils.

This indicates that residual oil with less than 0.3 weight percent sulfur is available in Hawaii, has been used by HECO in the past, and is available for import to Hawaii.

Third, the possible need for new handling facilities does not distinguish HECO from other steam generating unit owners and operators. In Hawaii, as elsewhere in the United States, depending on the type of oil purchased (a matter under the owner or operator's control), the use of very low sulfur oil may require installation of dedicated oil handling and storage facilities alongside of, or in place of, facilities handling higher sulfur content oil.

Finally, HECO claims that the increase in costs associated with complying with the exemption from the percent reduction requirement might result in "precluding" the use of new steam generating units on Oahu. HECO, however, does not explain its reasoning for this claim. HECO may mean, as it suggests with respect to the outer islands, that sources may construct diesel engines rather than steam generating units. This decision is for the source operator to make. The possibility that sources may construct diesel engines rather than steam generating units is not, however, a basis for modifying the standard.

For all of these reasons, an increase in the sulfur content of the oil exempted from the percent reduction requirement is not warranted for Hawaii.

7. Need for New Oil Transportation System in Hawaii

Petitioner's Comment: HECO also stated that, in order for neighboring islands (Maui, Kauai, Molokai, Lanai, and Hawaii) to use very low sulfur residual fuel oil a new inter-island transportation system (including vessels and delivery, receiving, and storage capacity) would have to be developed. Currently, all of the oil fired on these islands is imported in barges or tankers. Steam generating units on the neighboring islands fire oil with a sulfur content of 2 weight percent or less, which does not require a heated storage or distribution system. Importing waxy, very low sulfur residual oil would require heated barges for inter-island transport and a heated storage and distribution system on the islands. Coast Guard regulations prohibit hearing of the barges used for inter-island transport, and constructing a heated storage and distribution system would be uneconomical. HECO contended, therefore, that the Agency should exempt the Hawaiian outer islands from the SO_2 standards all together or permit the use of medium sulfur (2 weight percent) oil.

Agency Response: The nature of the inter-island transportation system in Hawaii does not warrant a special exemption for the outer islands. Residual oil capable of meeting an SO_2 emission limit of 130 ng SO_2/J (0.30 lb SO_2/million Btu) could be obtained by HECO, as discussed above. Based on information received from the Hawaiian Department of Energy (Docket No. A-83-27, Docket Item VI-E-9), the current method for transporting residual oil between the neighboring islands of Hawaii is by barge. This same system could be used to transport very low sulfur oil among the islands if slight modifications were made. These modifications could include cleaning some of the barges, dedicating them to the transport of very low sulfur oil, and equipping new steam generating units with new or converted storage tanks dedicated to the storage of very low sulfur oil.

Barge transport of fuel oil, far from being unique to Hawaii, is common practice throughout the continental United States. The Coast Guard does not prohibit the heating of barges transporting oil; it does have specific barge and heating system design requirements to ensure that oil is safely shipped (Docket A-83-27, Docket Item IV-E-10).

Depending on the type of oil purchased, a matter entirely under HECO's control, use of very low sulfur residual oil may require construction of a heated storage and distribution system. The need for this type of system, however, would be no different for a new steam generating unit located in Hawaii than for a similar unit located in the continental United States.

Therefore, an exemption from the standard for steam generating units located on the outer islands or an increase from 130 ng SO_2/J (0.30 lb SO_2/million Btu) to 867 ng SO_2/J (2.0 lb SO_2/million Btu) in the sulfur content of the oil exempted from the percent reduction requirement for the outer islands based on the need to make changes to the existing inter-island transport system or the cost of constructing a heated storage and distribution system is unwarranted.

8. Increased Use of Large Steam Generating Units or Gas Turbine Generators in Hawaii

Petitioner's Comment: HECO further stated that if it is required to comply with the 130 ng SO_2/J (0.30 lb SO_2/million Btu) SO_2 limitation, it would install gas turbine generators or electric utility steam generating units with heat inputs greater than 73 MW (250 million Btu/hour) rather than Subpart Db units. According to the petitioner, such large utility steam generating units and gas turbine generators could comply with Subparts Da or GG by using the 0.5 weight percent sulfur residual oil available on Oahu.

Agency Response: Subpart Db applies to steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour), except for electric utility steam generating units covered by Subpart Da. Indeed, the petitioner could install electric utility steam generating units in excess of 73 MW (250 million Btu/hour) heat input or a gas turbine generator and be subject to Subpart Da or GG, respectively, rather than Subpart Db. Large electric utility steam generating units or gas turbine generators can comply with the SO_2 requirements of Subparts Da or GG by firing 0.5 weight percent sulfur oil.

9. Economic Impacts of Firing Low Sulfur Oil in the Hawaiian Outer Islands

Petitioner's Comment: HECO noted that the cost differential between distillate oil and residual oil makes the use of distillate oil in steam generating units impracticable on the outer islands compared to diesel engines. The result, according to HECO, is that no one will build steam generating units; rather, they will burn distillate oil in more efficient diesel engines.

Agency Response: The SO_2 standards merely limit the sulfur content of oil that may be fired without meeting the 90 percent reduction requirement. The standards do not require new steam generating units taking advantage of this exemption to fire distillate oil, but permit new steam generating units to fire any type of oil. That HECO might find it more economical to make use of diesel engines to produce electricity does not make the standard unreasonable. As stated earlier, the Agency believes that residual oil containing less than 130 ng SO_2/J (0.30 lb SO_2/million Btu) is available and can be supplied to steam generating units in Hawaii. HECO, however, always has the option of using distillate oil, residual oil, or even crude oil, or of switching between these fuels, based on its own assessment of fuel costs, supply uncertainties, and other factors. Furthermore, if transportation costs or use of very low sulfur content oil in the Hawaiian Islands becomes too expensive, HECO may wish to consider partial scrubbing of higher sulfur content oil to achieve the 130 ng/J (0.30 lb/SO_2 million Btu) emission limit.

B. Post-Proposal Developments

1. New Docket Material

Petitioner's Comment: CIBO contended that EPA introduced new material into the docket and conducted new analyses of existing data after the close of the public comment period, and that the public was not given sufficient opportunity to comment on this new material.

Agency Response: In the proposed SO_2 rulemaking of June 19, 1986, EPA stated that the energy price scenarios would be updated between proposal and promulgation to determine whether the costs, emission reductions, or cost effectiveness of the rule would be altered significantly, and, when completed, this information would be added to the docket. (See 51 FR 22387.)

On April 27, 1987, and again on October 30, 1987, a notice of document availability was sent to parties who commented on the June 19, 1986, proposed rulemaking, informing them that new materials and analyses were being added to the docket. These notices included a listing of more than two dozen new reports related to the rulemaking, which can be found in Docket No. A-83-27. Copies of four of the reports, including the results of the "new boiler survey," were attached to the April notice and six were attached to the October notice.

None of the petitioners commented on these new materials nor did they submit any additional information. Further, the new analyses showed no significant differences from the analyses that led to the development of the proposed standard and reaffirmed the reasonableness of the final standard.

2. Analysis of the "New Boiler Survey"

Petitioner's Comment: CIBO objected to a question in the "new boiler survey" which asked, "Would your decision to build a new boiler change if projected costs to produce steam increased by: 10, 20, 30, or 50 percent?" The petitioner contended that this question was misleading because it failed to reveal the source of the increased cost of meeting the 90 percent SO_2 emission reduction requirement. The petitioner also contended that the question failed to address costs, other than incremental steam cost, that would affect project viability. The petitioner suggested that the question be rephrased to ask, "Would your decision to install a coal- or oil-fired boiler change if such boiler were subject to a requirement (1) that 90 percent of potential SO_2 emissions be removed on a continuous 30-day average basis (including start-up and shutdown periods), and (2) that the installation of low sulfur fuel-firing capability might need to be installed for periods of FGD system malfunction?"

Agency Response: The purpose of the "new boiler survey" was to determine to what extent new steam generating units may be replacements for existing units and what impact this may have on overall SO_2 emissions. Thus, the survey focused on the reasons motivating the installation of new units, the disposition of existing units that may be replaced by new units, and the overall impact of the installation of new units on SO_2 emissions. The specific question on costs was included in the survey to gauge how sensitive decisions to install new units, including those units that may replace existing units, may be to potential increases in costs. The petitioner hypothesized that the answers might have been different if EPA had formulated its question to specify that increased costs resulted from pollution control. In determining the cost of steam, prudent business practices would be to include all the costs associated with steam production, including any costs associated with pollution control and steam supply reliability. It is the magnitude, not the origin, of costs that is relevant to the elasticity of sales as a function of costs. No details or data were provided to support CIBO's conjecture. Unsupported conjecture is not an adequate basis for reconsidering a rule.

3. Reevaluation of SO_2 Emission Reductions

Petitioner's Comment: CIBO also contended that EPA failed to reevaluate SO_2 emission reductions in light of the data received from the "new boiler survey" conducted after proposal of the standards. Specifically, the petitioner contended that the SO_2 emission rates used by EPA were too high and, as a result, SO_2 emission reductions were overestimated. The petitioner also contended that the overall emission rate gleaned from the survey demonstrates that a 1,100 ng SO_2/J (2.5 lb SO_2/million Btu) heat input baseline for new coal-fired steam generating units is unjustifiably high. The petitioner also contended that the survey demonstrates that SO_2 emission rates for oil-fired units were overestimated. The petitioner stated that without an accurate estimate of emission reduction, EPA cannot fulfill its statutory obligation under the CAA to accurately determine the cost of achieving the emission reductions that any particular standard will impose.

Agency Response: The Agency did analyze the impacts of the SO_2 standards using SO_2 emission rates from the "new boiler survey." In fact, for every analysis of national impacts performed by EPA, both prior to and after proposal of the standards, the Agency included regulatory altenratives that were essentially the same as the emission rate indicated by the survey to represent baseline levels. Because the Agency analyzes the incremental impacts of each regulatory alternative over the next less stringent alternative, the designation of a particular emission level as "baseline" rather than a "regulatory alternative" has little practice effect. The incremental differences will be the same in either case.

Each of the Agency's analyses included emission levels lower than 1,100 ng SO_2/J (2.5 lb SO_2/million Btu) for coal-fired units and 1,300 ng SO_2/J (3.0 lb SO_2/million Btu) for oil-fired units. For example, each analysis included an alternative based on an emission level of 520 ng SO_2 /J (1.2 lb SO_2/million Btu) and 340 ng SO_2/J (0.8 lb SO_2/million Btu) for coal- and oil-fired units, respectively. These emission levels are essentially the same as those the petitioner believes can be gleaned from the survey as representative of baseline emission levels.

In each analysis, the impacts of the regulatory alternative eventually promulgated as the SO_2 standards were analyzed relative to less stringent alternatives, including an emission level essentially comparable to the "revised baseline" level proposed by the petitioner. In each instance, the impacts of the promulgated standards were reasonable compared to this "revised baseline" level. Consequently, the Agency did analyze the impacts of the standards in light of the results of the survey and found those impacts to be reasonable.

4. Information on Impacts of Waste Disposal

Petitioner's Comment: CIBO argued that post-proposal information showed that significant waste disposal problems would be created by the SO_2 standards. It also argued that methods used in some areas for disposing of sodium scrubber waste (i.e., deep well injection, use of lined disposal sites) are not cost effective, making the use of coal-fired steam generating units impracticable.

Agency Response: Steam generating units generally do not operate in isolation from other industrial processes, but are most often part of a larger industrial manufacturing plant that itself often produces substantial quantities of wastes requiring disposal. In addition, coal-fired steam generating units generate fly ash as well as liquid feedwater and steam system "blow-down" wastes, which also require disposal. Thus, use of SO_2 control systems to reduce SO_2 emissions from steam generating units may increase the volume of wastes to be disposed of, but generally does not create a new problem (i.e., a need to dispose of wastes where no such need existed before).

In areas where disposal of waste streams from sodium FGD or any other FGD system is considered by the owner or operator of a new steam generating unit covered by the NSPS to be too costly, the owner or operator could select an alternative approach to comply with the NSPS. As discussed throughout volume 4 of the "Background Information Document," the "SO_2 Control Technology Updates Report," and the "Summary of Regulatory Analysis," the SO_2 standards are based on a wide variety of techniques for controlling or reducing SO_2 emissions. The types of waste produced by FGD systems are quite different. As a result, a steam generating unit owner can select the FGD system best suited to local waste disposal requirements. Sodium FGD systems, for example, produce a liquid waste requiring disposal. Lime spray drying systems and FBC systems, on the other hand, produce a dry waste product. The cost impacts associated with each of these SO_2 control technologies, including the costs of waste disposal, are considered reasonable. Thus, one can minimize problems associated with increased waste disposal by appropriate selection of the SO_2 control system. The NSPS does not create an insurmountable waste disposal problem nor does it make the use of coal-fired steam generating units impractical. Finally, even though not a basis of the standard, if the steam generating unit owner or operator views the cost of these control techniques as excessive, switching to an alternate fuel, such as natural gas or very low sulfur oil, which imposes no additional waste disposal requirements, is an option.

5. Ability of FBC and FGD Systems to Achieve 90 Percent SO_2 Reduction

Petitioner's Comment: CIBO questioned the ability of FBC units to achieve 90 percent SO_2 reduction, especially those units experiencing large load swings. In addition, the petitioner stated that new information on spray dryer FGD systems does not support the ability of this technology to meet the 90 percent SO_2 reduction requirements. The petitioner claimed that EPA relied on switching to natural gas, and that such reliance violated EPA's duty to promulgate a standard that is achievable for coal- and oil-fired units.

Agency Response: As discussed in Volume 4 of the "Background Information Document," sufficient short-term performance test data exist to demonstrate that FBC technology is capable of achieving 90 percent SO_2 removal. Short-term data presented in the "Summary of Regulatory Analysis" show that several FBC units achieved 90 percent or greater SO_2 control during the test periods. Longer term data (30 days or more) also demonstrate that FBC units care capable of achieving greater than 90 percent SO_2 removal at high reliability levels. A 30-day test on a bubbling bed FBC unit burning high sulfur coal showed SO_2 removal efficiencies averaging 93.5 percent. A 30-day test conducted at another site showed an average SO_2 removal of 90 percent with greater than 99 percent reliability. During a 67-day period at this site, the FBC unit had a reliability of 97 percent. In addition, vendors have consistently stated that FBC units can be designed to achieve 90 percent SO_2 removal at high reliability levels. Based on these data, EPA believes that FBC has demonstrated the ability to meet the 90 percent SO_2 reduction requirement in the promulgated standards.

In response to the petitioner's comment regarding the ability of FBC units to respond to load swings, FBC technology is characterized by the large thermal mass of the bed, which in turn limits the ability of FBC units to adjust quickly to large variations in steam demand. This is a characteristic of FBC technology that is unrelated to SO_2 removal. As a result, the owner of a facility with rapidly changing steam demands is likely to select a conventional steam generating unit and FGD system, rather than an FBC, due to this inherent characteristic of FBC technology, which limits its ability to respond to large load swings.

The percent reduction and reliability of lime spray drying have also been demonstrated, as discussed in Volume 4 of the "Background Information Document" and as documented in the "Summary of Regulatory Analysis" and the "SO_2 Control Technology Update Report." Although few long-term (30 day and longer) data are available to demonstrate high SO_2 removal levels, short-term tests indicate that lime spray drying systems are capable of achieving percent reduction levels in excess of 90 percent. Although most lime spray dryers today are operated at roughly 70 percent reduction to comply with the lower percent reduction requirements in Subpart Da and in State permits, there is no reason to believe lime spray dryers cannot achieve 90 percent SO_2 reduction while maintaining a high degree of reliability. In fact, those periods during which high removal levels have been achieved in percent reduction tests indicate that lime spray drying systems are capable of achieving high percent reduction levels with high reliability levels. In addition, as with FBC technology, a vendor has also stated that lime spray dryer FGD systems can be designed to achieve 90 percent SO_2 removal at high reliability levels (Docket No. A-83-27, Docket Item VI-D-5). For these reasons, EPA believes that lime spray drying has demonstrated the ability to meet the 90 percent SO_2 reduction requirement in the promulgated standards. (See 52 FR 47837.)

In this connection, EPA stated in the promulgation preamble that one vendor's guarantee that 95 percent reliability was achievable in industrial applications was "consistent" with the results of 2 years operation of a lime spray drying system on a 132 MW (450 million Btu/hour) heat input coal-fired steam generating unit. (See 52 FR 47837; see also Docket A-83-27, Docket Item IV-B-9.) This statement remains true. The distinctions noted by the petitioner between this application and industrial applications regarding removal rates and load levels do not invalidate the comparison. The lower removal rate does not mean that EPA is incorrect in judging that higher removal rates can be achieved in industrial applications. Likewise, differences in loads do not mean that EPA's judgment is mistaken that load changes can be managed. The Agency's use of the comparison was fair. The example was not used as direct proof of reliability. It served as a useful, but not necessary, illustration that the vendor guarantee in question was realistic. Moreover, the Administrator's determination that the standard was reasonable was not based on the assumption that fuel switching would occur.

6. Use of Vendor Statements to Support 90 Percent SO_2 Reduction

Petitioner's Comment: CIBO stated that informal vendor statements had been used to support that assertion that lime spray dryers can achieve a 90 percent SO_2 reduction. The petitioner asserted that a vendor guarantee does not reflect "adequately demonstrated" performance because the standard "must be based on cost-effective technologies that can be successfully and reliably used in operating installations." The petitioner also stated that EPA did not provide notice of how much EPA relied on vendor guarantees in finding that lime spray dryers are "demonstrated."

Agency Response: Data, analysis, and engineering judgment were used to establish the 90 percent SO_2 reduction standard. The vendor guarantee was used merely to confirm the regulatory decision and not as the sole basis for the standard. The term "adequately demonstrated" does not mean "successfully and reliably used in operating installations." An "achievable" standard need not be already routinely achieved in the industry. [See *National Lime Association v. EPA*, 627 F.2d 416 (1980); *Sierra Club v. Costle*, 657 F.2d 298 (1981); and *Portland Cement Assn. v. Ruckelshaus*, 486 F.2d 375 (1973).] Rather, to be achievable, the standard must be achievable under most adverse conditions that can reasonably be expected to occur. (See *National Lime, supra.*)

The vendor in question is a leading spray dryer FGD manufacturer, having installed over 50 percent of the existing units, and is a reliable and authoritative source of information on dry FGD systems. The vendor's statements were only used to support the data and engineering judgment that served as the basis of the standards. CIBO's criticisms of such guarantees are not "centrally relevant" to the outcome of rule. In fact, EPA's determination that the lime spray technology was "demonstrated" was based, in the proposal as in the final rule, on the data in the record and its judgment that high levels of performance and reliability were achievable. The Agency noted the availability of performance guarantees at the time of proposal only as additional support for, but not the basis of, its position. (See e.g., BID, Volume 4.)

IV. Summary

The issues raised in each petition and discussed in this notice were carefully considered; however, only the issue concerning cost impacts of the NO_x standard on very low capacity factor steam generating units provides a basis for revising the promulgated standards. A proposal to do so will be made in a separate notice. The other issues raised by petitioners do not require or justify reconsideration of the promulgated PM, SO_x, or NO_2 standards under Section 307.

Date: January 6, 1989.

Lee M. Thomas,

Administrator.

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