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Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-453/R-98-005
September 1998

Air

EPA

New Source Performance Standards, Subpart Da and Db - Summary of Public Comments and Responses

EPA-453/R-98-005

New Source Performance Standards,
Subparts Da and Db

Summary of Public Comments and Responses

Emission Standards Division

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Part, North Carolina 27711

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1.0 SUMMARY

The EPA proposed amendments to subparts Da and Db of 40 CFR part 60 on July 9, 1997. The purpose of this document is to present a summary of the public comments received on the proposed amendments to subparts Da and Db of 40 CFR part 60 and the responses developed by the EPA. This summary of comments and responses serves as the basis for revisions made to the standards between proposal and promulgation.

The EPA received 70 public comment letters on the proposed rule changes. The commenters represent the following affiliations: government (5), utility industry (26), industrial boiler users (13), public interest and environmental groups (7), private citizens (4), fuel producers (11) and other (4). This document incorporates all the comments in the docket and some additional comments that will be added to the docket. Table 1-1 presents a listing of all persons submitting written comments, their affiliation, and their docket number (if available). No comments were received at the public hearing.

TABLE 1-1. LIST OF COMMENTERS ON THE PROPOSED REVISIONS TO SUBPARTS Da AND Db

Number[a]	Commenter, Addressee, Title or Description, etc.	Date of Document
1	J. Brax, Air Quality Intern, Environmental Defense Center, Santa Barbara, CA	09/2/97
2	R. Machaver, RJ Associates, Lincoln, MA	09/3/97
3	A. Bodnarik, ICCR Boiler Workgroup Member, State of New Hampshire Department of Environmental Services Air Resources Division, Concord, NH	09/5/97
4	G. Kamaras, Director, Energy Advocacy Program, Legal Environmental Assistance Foundation, Tallahassee, FL	08/20/97
IV-D-01	J.D. Baird, Manager, Environmental Services, Hunt Wesson, Inc., Fullerton, CA	08/5/97
IV-D-02	K. Bailey, Chadbourne & Parks, LLP, Washington, DC on behalf of the American Forest & Paper Association, Inc.	08/7/97
IV-D-03	R.I. Zvaners, Senior Manager, Environmental Policy, Chemical Manufacturers Association, Arlington, VA	08/20/97
IV-D-04	F.W. Hottenroth, Private Citizen, Seal Beach, CA	06/19/97
IV-D-05	J.W. Clarke, Private Citizen, Rockville, MD	08/20/97
IV-D-06	C.W. Whitmore, Principal, Whitmore Associates, Shawnee Mission, KS	08/19/97
IV-D-07	M.A. Curtis, Executive Director, New Jersey Environmental Lobby, Trenton, NJ	08/21/97
IV-D-08	T.A. Elter, Sr., Environmental Analyst, Niagra Mohawk Power Corporation, Syracuse, NY	08/25/97
IV-D-09	R.M. Salmon, Coordinator, Environmental Services/Public Works Projects, City of Tampa, FL	09/5/97

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IV-D-10	S. Shell, Manager, Environmental, Safety, and Health, Lockheed Martin Utility Services, Inc., Paducah, KY	09/5/97
IV-D-11	T.J. Porter, Director, Air Quality Management, Wheelabrator Environmental Systems, Inc., Hampton, NH	09/5/97
IV-D-12	G.K. Crane, Executive Vice President, Environmental, Ogden Projects, Inc., Fairfield, NJ	09/5/97
IV-D-13	M. Zannes, President, Integrated Waste Services Association, Washington, DC	09/5/97
IV-D-14	E.D. Yates, Sr. Vice President, California League of Food Processors, Sacramento, CA	09/5/97
IV-D-15	D. Hearth, Bracewell & Patterson, L.L.P., Washington, DC	09/5/97
IV-D-16	J.W. Dwyer, President, Lignite Energy Council, Bismarck, ND	10/3/97
IV-D-17	J.A. Miakisz, Director Environmental Regulatory Affairs, Niagara Mohawk Power Corporation, Syracuse, NY	10/2/97
IV-D-18	B. Mathur, Chief, Bureau of Air, Illinois Environmental Protection Agency	10/7/97
IV-D-19	A. Lee, Senior Staff Environmental Engineer, Texaco, Inc., Beacon, NY	10/3/97
IV-D-20	B.A. Craig, Director, Utility and Environmental Regulatory Affairs, Natural Gas Supply Association, Washington, DC	10/6/97
IV-D-21	L.J. Becker, Environmental Analyst, San Diego Gas & Electric, San Diego, CA	10/3/97
IV-D-22	N.L. Morrow, Exxon Chemical Americas, Houston, TX	10/6/97

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IV-D-23	S.B. Peirce-Sandner, KP Environmental Services, Eastman Kodak Company, Rochester, NY	10/6/97
IV-D-24	N. Stafki, Senior Environmental Analyst, Northern States Power Company, Minneapolis, MN	10/3/97
IV-D-25	N. Ford, Sierra Club, Ohio Chapter Energy Committee, Cincinnati, OH	10/7/97
IV-D-26	J.J. Mayhew, Assistant Vice President Environmental & Policy Analysis, Chemical Manufacturers Association, Arlington, VA	10/8/97
IV-D-27	T. Romero, U.S. Generating Company, Bethesda, MD	10/7/97
IV-D-28	B.E. Ramsey, Executive Director, Anthracite Region Independent Power Producers Association, Lemoye, PA	10/7/97
IV-D-29	D.W. Marshall, Staff Attorney, Conservation Law Foundation, Concord, NH	10/7/97
IV-D-30	K.A. Colburn, Director, Air Resources Division, New Hampshire Department of Environmental Services, Concord, NH	10/7/97
IV-D-31	G. Schaefer, Director, Government Issue & Analysis, ARCO Coal Company, Denver, CO	10/7/97
IV-D-32	R.L. White, Vice President, Environmental Services, Texas utilities Services, Inc., Dallas, TX	10/7/97
IV-D-33	E.S. Roy, Vice President, Intercontinental Energy Corporation/R.D. Ain, Senior Vice President, Cogen Technologies	10/7/97
IV-D-34	M. Spurr, Legislative Director, International District Energy Association, Washington, DC	10/7/97

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IV-D-35	M.R. Robida, Manager - Air Quality, American Electric Power, Columbus, OH	10/7/97
IV-D-36	M.J. Ruffatto, President, North American Electric Power Group, Ltd., Greenwood Village, CO	10/7/97
IV-D-37	C. Seidlits, President & CEO, Association of Electric Companies of Texas, Inc., Austin, TX	10/7/97
IV-D-38	S.M. Ruffin, Environmental Services Department, South Carolina Electric & Gas Company, Columbia, SC	10/7/97
IV-D-39	M.C. Hall, Manager, Legislative and Regulatory Affairs, Trigen Energy Corporation, White Plains, NY	10/7/97
IV-D-40	P. Glaser, Attorney at Law, Doherty, Rumble & Butler, Washington, DC on behalf of F.D. Palmer, GM & CEO, Western Fuels Association, Inc., Denver, CO	10/8/97
IV-D-41	R.L. Brubaker/C.F. Barry, Attorneys at Law, Porter, Wright, Morris & Arthur, Columbus, OH on behalf of Ohio Edison Company	10/8/97
IV-D-42	D.J. Jezouit, Counsel to the Class of '85 Regulatory Response Group, Baker & Botts, LLP, Washington, DC	10/8/97
IV-D-43	T.L. Fisher, Chairman, American Gas Association/Chairman, Natural Gas Council; L.D. Hall, Chairman, Interstate Natural Gas Association of America; L.O. Ward, Chairman, Independent Petroleum Association of America; M.E. Wiley, Chairman, Natural Gas Supply Association	10/8/97
IV-D-44	R. Cooper, Senior Vice President, Government Relations, American Gas Association, Arlington, VA	10/8/97

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Number[a]	Commenter, Addressee, Title or Description, etc.	Date of Document
IV-D-45	R.C. Kaufmann, Director, Air Quality Program, American Forest & Paper Association, Washington, DC	10/8/97
IV-D-46	Coalition for Gas-Based Environmental Solutions, Arlington, VA	undated
IV-D-47	F.W. Brownell/C.S. Harrison, Hunton & Williams, Washington, DC on behalf of Utility Air Regulatory Group and the National Mining Association	10/8/97
IV-D-48	S.H. Segal, Counsel to the Council of Industrial Boiler Owners, Bracewell & Patterson, LLP, Washington, DC	10/8/97
IV-D-49	S. Hedman, Environmental Law & Policy Center, Chicago, IL	10/8/97
IV-D-50	J. Grumet, Executive Director, Northeast States for Coordinated Air Use Management (NESCAUM), Boston, MA	10/8/97
IV-D-51	M.S. Brownstein, Esq., Environmental Policy Manager, Air Quality, Public Service Electric and Gas Company, Newark, NH	10/8/97
IV-D-52	B. Green, Environmental Manager, Kennecott Energy Company, Gillette, WY	10/8/97
IV-D-53	M.W. Stroben, Manager, EHS Technical Analysis Corporate Environment, Safety & Health, Duke Energy Corporation, Charlotte, NC	10/8/97
IV-D-54	C. Johnson, Deputy Commissioner, New York State Department of Environmental Conservation, Albany, NY	10/8/97
IV-D-55	A.W. Hadder, Manager, Environmental Policy and Compliance, Virginia Power	10/8/97

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Number[a]	Commenter, Addressee, Title or Description, etc.	Date of Document
IV-D-56	M.G. Dowd, McGuire, Woods, Battle & Booth, L.L.P., Richmond, VA on behalf of P.J. Margaritis, Senior Vice President Tractebel Power, Inc., Houston, TX	10/9/97
IV-D-57	M.J. Wax, Deputy Director, Institute of Clean Air Companies, Washington, DC	10/7/97
IV-D-58	D. Heminway, Assistant Director, Citizens' Environmental Coalition, Medina, NY	9/29/97
IV-D-59	L.E. Watkins, Jr., General Counsel, Sunflower Electric Power Corporation, Hays, KS	undated
IV-D-60	L.S. Beal, Director, Environmental Affairs, Interstate Natural Gas Association of America, Washington, DC	10/8/97
IV-D-61	J.L. Woolbert, Engineering Associate, Eastman Chemical Company, Longview, TX	10/7/97
IV-D-62	D. Marrack, M.D., Fort Bend Medical Clinic, Houston, TX	10/4/97
IV-D-63	W.R. Watson, Sr. Environmental Professional, Illinois Power Company, Decatur, IL	10/6/97
IV-D-64	A. Deshmukh, Environmental Specialist-Air Quality, Occidental Chemical Corporation, Dallas, TX	undated
IV-D-65	P. Bailey, Director, Health and Environmental Affairs, American Petroleum Institute, Washington, DC	10/9/97
IV-D-66	A. Titus, A. Bisantz, Private Citizens, Batavia, NY	7/1/97

[a] The docket number for this rulemaking is A-92-71.

2.0 BEST DEMONSTRATED NO_x CONTROL TECHNOLOGY

2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

Several commenters raised concerns that the determination that SCR represents the best demonstrated technology is not adequate. Following is a summary of their comments, and the EPA's response.

Comment: Coal-fired industrial boilers. Commenters IV-D-23 and IV-D-26 stated that the EPA should not consider SCR as the best demonstrated technology for coal-fired industrial boilers. Commenter IV-D-23 recommended that adequate pilot-plant testing be conducted for these boilers. Commenter IV-D-31 added that "it is doubtful whether any of the SCR units that EPA points to could operate under an emission limit this low." Commenter IV-D-23 noted that SCR is installed on only 7 coal-fired units in the U.S., all of which are electric utility units. In addition, none of the 200 European and Japanese units with SCR cited by the EPA are industrial units. Because the EPA has cited no industrial units that use SCR successfully, Commenter IV-D-23 asserted that this technology is not adequately demonstrated.

Commenter IV-D-48 stated that the EPA presented no evidence of any coal-fired industrial boilers that employ SCR. This lack of demonstrated technology "does not support imposition of SCR as the minimum NSPS control level." The commenter recommended that the EPA consider the potential problems associated with SCR, including costs, catalyst poisoning, and oil ash coating the catalyst, when finalizing the NSPS. The commenter suggested that the standards for coal- and oil-fired boilers be based on the use of low NO_x boilers, staged combustion, and/or selective noncatalytic reduction (SNCR) which have had some demonstration in industrial units.

Two major problems cited by Commenter IV-D-60 were deactivation of the catalyst from alkali sulfates, and excess sulfur trioxide (SO_3) in the flue gas. The commenter contended that the EPA casually dismissed alkali poisoning without justification. According to the commenter, excess SO_3 can lead to increased downstream corrosion and negative impacts on the heat rate of the unit.

Commenters IV-D-38 and IV-D-41 stated that “the relevant technological art is immature...standards rooted in it will not be attainable on a sustained basis unless they are flexible,” and that the results of the EPA's examination of SCR and SNCR were inconclusive. Commenter IV-D-38 added that the flexibility would need to account for variabilities in the empirical data, and need “to accommodate phenomena about which the EPA has no data.” Commenter IV-D-63 remarked that "the standards set in this rulemaking are beyond the envelope of today's technology."

Commenters IV-D-32 and IV-D-37 stated that the coal-fired and natural gas power plants could not meet a 0.15 lb/MMBtu standard without implementing costly SCR technology. The commenter remarked that the reported cases of successful SCR applications are extremely limited, with success being measured on the basis of short-term performance and without cost considerations.

<u>Coal-fired utility boilers</u>. Commenter IV-D-52 stated that SCR has only been applied to coal-fired [utility] boilers over that past two years. The commenter added that this is “indicative of a <u>developmental</u> phase of technology,” noting that these sample sizes are not valid for any verifiable statistical comparisons.” The commenter also noted that there appears to be a discrepancy between when the EPA stated that SCR and SNCR technologies “have been applied widely to commercial-scale gas- and oil-fired steam generating units” and when the EPA explained that statistical analysis of combustion control was not performed

since either (1) no applicable operating subpart Da units are known to exist, or (2) during development of the proposal, long-term CEM data were unavailable.

Appropriateness of SCR at pulp and paper mills. Commenter IV-D-45 indicated that SCR is not appropriate for industrial boilers, particularly combination boilers at pulp and paper mills that burn wood and fossil fuels. The commenter explained that boilers at paper mills are subject to wide, sudden changes in load that complicate the use of SCR. Other potential problems include high particulate loadings, high potential for sulfur poisoning of the catalyst, and difficulty in maintaining the temperatures necessary to minimize NO_x and HAP generation.

Residual oil-fired boilers. Commenters IV-D-19 and IV-D-65 stated that the EPA's data have not demonstrated that SCR technology reduces emissions from residual oil-firing steam generating units for the Db standard. Therefore, the commenters recommended that the EPA retain the current standard of 0.30 lb NO_x/MMBtu. Commenter IV-D-19 added, that if the EPA insists on a single performance standard of 0.20 lb per MMBtu, that the EPA allow for an annual averaging period for this performance standard.

Response: The first issue raised by several of the commenters is that EPA's determination that SCR represents BDT for a range of boiler type and operating conditions is not adequate. The EPA disagrees and believes the data base that supports the BDT decision is adequate for two reasons. First, the proposal data base resulted from an extensive review on the available domestic and international SCR units in use in the industry at the present time. However, in response to the comments, the EPA has obtained data from three more utility boilers that utilize SCR and represent a range of operating conditions and coal types. The first utility boiler (U.S.

Generating Company's Logan plant) is a 225-megawatt pulverized-coal cogeneration facility, and is operated under cycling conditions. This facility submitted 3 months of NO_x emission data to EPA. The analysis of these data indicate that the facility is capable of achieving the input-based NO_x standard of 0.15 lb/MMBtu and the revised output-based standard of 1.6 lb/MWh on a 30-day rolling average. (See section 5.2 for a discussion of the development of the revised output-based standard.) The second plant is the Birchwood Power Facility (jointly owned by Southern Energy Incorporated and Cogentrix), which was described in *Power Engineering* (December 1997, pp. 28-30). Birchwood is a 240-megawatt cogeneration facility with cycling load that began operation in 1996. Birchwood is required to meet a NO_x emission standard of 0.10 lb/MMBtu on a 30-day rolling average. Actual test results show that the facility achieves NO_x emissions of 0.77 lb/MWh at low load conditions, easily attaining the output-based standard. The third facility is a 464-megawatt utility boiler firing bituminous coal (Stanton Energy, Florida). This facility is currently meeting its permitted emission limit of 0.17 lb/MMBtu. If this facility were to improve the performance of its SCR to 0.15 lb/MMBtu, this facility would be capable of meeting the 200 ng/J (1.6 lb/MWh) output-based limit.

Second, this data base is adequate to evaluate the factors that can potentially affect SCR performance in a wide range of operating conditions. According to the subpart Da Background Information Document (BID), the performance of an SCR system is influenced by six factors: flue gas temperature, NH_3/NO_X ratio, NO_X concentration at the SCR inlet, gas flow rate, and catalyst condition. Low temperatures result in a failure or slowdown in NO_X reduction, which is a particular issue when the boiler is operating at a low-load condition. Fundamentally, like all post-combustion control devices, SCR is designed to respond to the characteristics of the stack gas. The primary difference between utility and nonutility boiler types may be that, on average, non-utility boilers may be more likely to operate with fluctuating loads. This difference in operating pattern may appear to have an impact on the characteristics of the stack gas. However, the NSPS is based on a 30-day averaging period to accommodate normal fluctuations in performance. Further, as discussed above, new analyses of two facilities that operate under cycling conditions have shown that SCR can meet the proposed standard over a 30-day averaging period. The Birchwood facility reports daily cycle variations from 32 percent to 100 percent of load. The Logan facility’s daily cycles ranged from 28 percent to 84 percent in the 3-month period for which data were supplied.

Another load-related technical issue raised in the case of pulp and paper is the difficulty in maintaining the temperatures necessary to minimize NO_x and HAP generation. In general, while designing an SCR system for a boiler, the boiler duty is taken into consideration. Specifically, the expected temperature range at the exit of the economizer is factored into the selection of an SCR catalyst formulation.

There are other steps that operators can take to ensure the desired SCR performance under variable or low load conditions. For example, if low load contributes to insufficient gas velocity to keep the flyash in suspension, the operator can add an ash hopper to divert the ash from the reactor and catalyst face. Alternatively, good ductwork system design can avoid these problems. Also, low boiler exit temperatures can be avoided by adding a economizer by-pass to keep the gas temperature higher at low loads. Finally, good flue gas mixing can overcome differences in gas flows and boiler firing conditions. (Robinson, T. And Croteau, P., “Adapting the German Coal-Fired SCR Experience to the U.S.” Presented at the Council of

Industrial Boiler Owners NO_x Control XI Conference, February 1998.) Taking into consideration all of the above, in general, the EPA does not believe that SCR use is constrained by boiler duty.

Several commenters raised catalyst poisoning as an illustration that SCR is not suitable for all units. As a result of developments in catalyst technology, formulations are currently available that minimize the impact of poisoning. Nevertheless, the EPA believes this issue is really related to the cost of operating the SCR; catalyst; appropriate catalyst management plans now make it possible to maximize catalyst life under plant operating conditions.

Another issue raised by commenters is that the SCR technology is immature and insufficiently demonstrated. The EPA disagrees with this comment. One recent study (Khan, S., et al, “SCR Applications: Addressing Coal Characteristic Concerns.” Presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997) identified at least 212 worldwide SCR installations on coal-fired units, which cover different types of boilers subjected to varying operating conditions and firing a variety of coals. Some of these installations were designed for and have achieved high NO_x reduction levels, exceeding 90 percent. Plants in Europe have been continuously using SCR for over 10 years. (Robinson, T., and Croteau, P., “Adapting the German-Coal-fired SCR Experience in the U.S.” Presented at Power-Gen International 97, December 1997.) Finally, SCR-equipped units located in the U.S., such as the Logan, Birchwood, and Stanton facilities are meeting some of the most stringent NO_x limits in the country.

Comment: Coal-related issues. Commenter IV-D-47 provided a rigorous description of what would legally be considered "adequate demonstration", and concluded that the proposed NSPS are not adequately demonstrated for all U.S. coals, particularly medium- and high-sulfur coals. Previously, the commenter had urged the EPA not to base the NSPS on undocumented experience in Germany or Japan. The commenter also rejected the Department of Energy Plant Crist high-sulfur coal demonstration project because of its limited scope. Commenter IV-D-60 reported the same comment.

Additionally, Commenter IV-D-47 claimed that EPA’s analysis of U.S. coal usage is misleading. The commenter noted that "EPA claims that high-sulfur coal technical issues are irrelevant, because 85% of the coal fired in this nation has 2% or less sulfur content." The EPA reported coal consumption on a mass basis, which is biased toward high moisture, high ash content coal. The commenter indicated that coal use should be depicted on a Btu basis. Additionally, the commenter stated that coal use should be described on a regional basis. The commenter claimed that an analysis based on heat value and regional consumption would show that 48 percent of the coal burned east of the Mississippi is high-sulfur coal.

Commenter IV-D-63 added that the Japanese demonstration is on low-dust environment using a hot-side electrostatic precipitator (ESP), compared to most of the U.S. boilers which use cold-side ESP's.

Response: The EPA disagrees that the use of SCR for high-sulfur coal applications is unsupported. As noted in the Acid Rain Phase II NO_x Rule Response to Comments Document (p. 171), in addition to one coal-fired plant in Japan and another in Austria firing coals with sulfur contents of 2.5 percent of higher, there are two coal-fired SCR installations in the U.S., Chamber Works and Keystone Plants in New Jersey, that are firing coals with sulfur contents close to 2 percent. Northampton, which is equipped with SNCR, successfully burns waste coal, and meets some of the most stringent NO_x limits in the U.S. (0.10 lb/MMBtu). In the Plant Crist demonstration project, catalysts from various suppliers performed successfully. Criteria for successful performance at this demonstration included ammonia slip less than 5 ppm and SO_2 oxidation less than 0.75 percent.

In view of the experience both in the U.S. and abroad, the commenters’ concerns over the use of SCR for high-sulfur coal applications is unsupported. In general for these installations, design features such as low ammonia slip, a catalyst that minimizes SO_3 conversion, and an economizer bypass to maintain proper flue gas temperatures at low loads are provided.

The commenters said that the NSPS was not adequately demonstrated for the range of U.S. coals, particularly medium- and high-sulfur coals and that EPA’s analysis of U.S. coal usage is misleading. First, EPA’s analysis did specifically address medium- and high-sulfur coals. For example, page 6-12 of Subpart Da's BID estimates an indirect cost factor of 1.45, where it stated that “For the application of SCR to boilers burning medium- to high-sulfur coals, indirect costs may be greater than 45 percent of the process capital due to factors discussed in Chapter 3.” In any case the key issue is the impact that burning lower grade, higher sulfur coals has on SCR performance. Once again, this is more of a cost issue than a performance issue, because the major effect of burning some coal types is that the SCR catalyst may wear out more quickly or that problems such as plugging of the catalyst or additional cleaning requirements may add to the costs of using SCR in some applications. This issue is discussed further in section 3.3.

One commenter also says that the Japanese demonstration is on low-dust environment using a hot-side ESP, compared to most U.S. boilers, which use cold-side ESPs. Once again, this is a catalyst life issue.

2.2 SELECTIVE NONCATALYTIC REDUCTION (SNCR)

Other commenters argued that SNCR was not adequately demonstrated.

Comment: Fluidized bed combustion boilers (FBCs). Commenter IV-D-56 reported that SNCR has not been adequately demonstrated for use on circulating FBCs. Commenter IV-D-56 added that "due to the inherently low combustion temperature of circulating FBCs, SNCR cannot work properly on that type of boiler unless the boiler is operating at its maximum capacity rate." The commenter explained that the flue gas must be, generally, between 1700°F and 1800°F, in order for the chemical reaction that removes NO_x to occur. Further, Commenter IV-D-56 reviewed the EPA questionnaire and found that three of the five circulating FCBs that use SNCR stated that SNCR did not work properly when the units were operated at anything less than maximum capacity. Commenter IV-D-56 concluded this discussion by stating that the "EPA has no basis whatsoever for extrapolating data obtained from the application of SNCR to other types of boilers to conclude that SNCR is appropriate emission control technology for circulating FBC boilers that cycle their load."

Large boilers. Commenter IV-D-56 commented that SNCR "has not been adequately demonstrated to work on large boilers [with a rated capacity greater than 390 MMBtu/hr], whether circulating bed or not." Commenter IV-D-56 reviewed the data and reported that the rated capacity of the FBC boilers using SNCR that were analyzed by the EPA in developing the proposal ranged from 389 MMBtu/hr to 290 MMBtu/hr. The commenter concluded by stating that SNCR cannot be considered an adequately demonstrated emission control technology for FBC boilers greater than 390 MMBtu/hr rated capacity.

Response: According to the subpart Db BID (p. 3-43), flue gas temperatures exiting the furnace can range from 1,200 °C ±

110 °C (2,200 °F ± 200 °F) at full load down to 1,040 °C ± 70 °C (1,900 °F ± 125 °F) at half load. At similar loads, temperatures can increase by as much as 30 to 60 °C (50 to 110 °F) depending on the extent of ash deposition on heat transfer surfaces. Due to these variations in the temperatures, it is often necessary to inject the reagent at different locations or levels in the upper furnace or convective pass for effective NO_x reduction. A recent publication summarized the successful retrofit of retractable lances on a 100 MWe coal-fired utility boiler equipped with SNCR, which greatly improved low load performance. (Hunt, T., et. al, "Using Retractable Lances to Maximize SNCR Performance." Presented at the EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, August 1997) Finally, as noted in the subpart Db BID, the addition of hydrogen or other hydrocarbon reducing agent can be injected with the NH_3 to lower the effective temperature range. Similarly, additives can increase the temperature range of urea application. By taking these sorts of steps, the EPA believes that operators can successfully operate SNCR, even under low load conditions.

Recent analysis of NO_x emissions data from a 110-megawatt, base-loaded, circulating fluidized-bed boiler equipped with SNCR (U.S. Generating Company's Northampton plant) indicates that the facility is quite capable of meeting the proposed standard. This facility achieves average input-based emissions of 0.089 lb/MMBtu and output-based emissions of less than 0.8 lb/MWh, well below the output-based standard of 1.6 lb/MWh.

Regarding SNCR on large boilers, the Acid Rain Phase II NO_x Response to Comments Document (p. 212) notes that SNCR has been demonstrated on coal-fired units as large as 1,230 MMBtu/hr (Germany) and on oil-fired units as large as 2,900 MMBtu/hr (Niagara Mohawk's Oswego Station). The SNCR application on Oswego shows that injectors can effectively penetrate the combustion gas flow in large boilers. Since the effectiveness of injecting SNCR reagent into large boiler casings has been proven, and SNCR has been applied to a variety of boilers, the EPA does not see boiler size as a restriction for applying SNCR to NSPS sources.

2.3 NATURAL GAS REBURN

Comment: Commenters IV-D-19, IV-D-20, IV-D-61 and IV-D-65 recommended that the EPA recognize natural gas reburn, as well as SCR, as the demonstrated technology basis for Subpart Da sources. The commenters pointed out that this approach would be consistent with the Acid Rain NO_x programs.

Commenter IV-D-61 listed several advantages of reburn technology over the add-on controls proposed by the EPA:

(1) lower capital costs (one-third to one-half of SCR);
(2) minimal boiler modifications required;
(3) lower maintenance requirements;
(4) no costly catalysts;
(5) no downtime for catalyst replacement, and;
(6) demonstrated effectiveness on coal-fired industrial boilers in the U.S.

The commenter said that EPA’s assertion that the maximum potential emission reductions from this technology is only 50 percent, and therefore less than the other technologies considered, is in error. The commenter said that there are at least five commercial installations of the reburn technology in the U.S., and they are achieving NO_x emission reductions of 58-77 percent. In addition, coal, natural gas and other fuels can be utilized in the fuel rich zone.

Response: Commenter IV-D-61 refers to a paper from the August 1997 EPRI megasymposium, “Field Experience--Reburn NOx Control,” which presents the results of five full-scale retrofit applications of reburn technology. The paper describes design considerations and advantages of the technology. One unit is being equipped with a nitrogen agent injection system, which is expected to reach of goal of total NOx of 0.15 lb/million Btu (to date has achieved 0.2 lb/million Btu). Other commenters were worried that EPA's apparent exclusion of reburn is based on faulty rationale and contradicts acid rain rulemakings, which place SCR and reburn on the same level of effectiveness.

The EPA agrees that reburn technology may be a viable alternative to SCR in some situations. As structured, the NSPS would not preclude application of this or other innovative technologies, so long as they meet the emission standard. However, the EPA believes the existing analysis supporting SCR is adequate for purposes of supporting the selection of BDT.

3.0 CONTROL TECHNOLOGY COSTS

Several comments addressed the cost analysis performed by the EPA in support of the proposed standards.

3.1 ESTIMATED COSTS ARE TOO HIGH

Comment: Commenter IV-D-39 remarked that the EPA's NO_x control costs are too high and gave two reasons why: (1) the control costs should not be based on add-on control technologies; (2) the utilization of the industrial boilers is underestimated.

Commenter IV-D-57 asserted that the EPA has overestimated the cost of post-combustion NO_x controls, and that aggregate costs of the proposed standards would be less than the EPA estimates. The EPA cites costs of 2.1-3.3 mills/kWh and cost-effectiveness estimates of $1,460-2,270/ton for SCR on coal-fired electric utility boilers. The commenter cites one unit where actual SCR costs are 0.98 mills/kWh and approximately $1,200/ton. The commenter also states that the EPA has not considered recent strides in reducing reagent use, and operating cost, for SNCR installations. The commenter refers to one coal-fired utility boiler that reduced reagent use by 50 percent through a control upgrade, including continuous ammonia and temperature monitors, improved control hardware and software, and additional injector pressure controls.

Response: The EPA considered both the use of add-on controls and process modifications, including fuel switching, at proposal. That analysis showed that add-on control technology represented BDT in this case. The EPA’s analysis did consider the utilization rate of industrial boilers, which contributed to the selection of a higher emission limit (0.2 lb/MMBtu vs. 0.15 lb/MMBtu). As for commenter IV-D-57's example, EPA expects that costs of operating SCR will decrease as facilities gain experience in maintaining and operating these units. However, EPA believes the overall cost analysis presented at proposal fairly represents average costs to the industry.

3.2 ESTIMATED COSTS ARE REASONABLE

Comment: Commenters IV-D-19, IV-D-20, IV-D-26 and IV-D-65 voiced support of the Agency's conclusion that additional controls for new gas-fired and distillate oil-fired units are not cost effective. Commenters IV-D-19, IV-D-26 and IV-D-65 added "that is not clear whether EPA has taken into account the cost of "scope adders" in the construction of a new boiler or reconstruction of an existing one." Both commenters explained that the "scope" of the project reflects reconstruction of the boiler and "scope adders" may include significant site work, rerouting of lines, relocation of other equipment, and/or the costs of shutting down production. The commenters added that these costs may add 100 percent to the costs of simply constructing or reconstructing the [same] boiler (at a different site).

Response: The Agency appreciates the feedback from the commenters. Retrofit costs were included in the cost estimation, as noted in Docket Item II-A-21, App. A, page 4-3.

3.3 ESTIMATED COSTS ARE TOO LOW

Comment: Commenter IV-D-47 contended that the EPA cost estimates for SCR in the proposed rule were much too low, and that the cost analysis was inadequate. The commenter stated that the EPA extrapolated their costs "from an earlier study that had very different technical premises for SCR." This earlier study focused on retrofit costs for existing plants, and did not consider site layout, with boiler conditions not typical of new units. The commenter reported that the EPA estimates of SCR capital costs are only 65 percent of recently estimated values that were summarized at an EPA-Department of Energy (DOE)-Electric Power Research Institute (EPRI) technical conference.

The commenter asserted that the "EPA has not met the requirements of §111 and should withdraw its NSPS proposal." The commenter recommended that the EPA analyze options other than SCR for coal-fired boilers, and then "determine whether an SCR standard for coal-fired units is appropriate."

Commenter IV-D-37 reported that SCR systems require more energy to operate due to a pressure drop associated with the catalyst bed. The commenter stated that "by effectively requiring the use of SCR for solid fuel-fired units, EPA is encouraging the use of an energy-intensive emission control method to achieve marginally lower NO_X emissions..." In addition to the additional operational costs, Commenter IV-D-37 reported that there is fouling of air heater surfaces by ammonium salts, and waste disposal costs for the spent catalyst.

Commenters IV-D-23 and IV-D-45 pointed out several costs associated with SCR and fuel switching for coal-fired industrial boilers that were not considered by the EPA cost estimates. Commenter IV-D-23 provided items (1) through (5) and Commenter IV-D-45 provided item (6).

(1) There are several components in U.S. coals (e.g., alkaline metals, heavy metals, chlorine, and fluorine) that could significantly shorten the catalyst life. The EPA estimate assumed a catalyst life of 5 years. If the lifespan is reduced to 2-3 years, the effect is a doubling in the cost of the catalyst, which is already estimated to be 30 percent of the SCR cost with a 5-year lifespan.

(2) Ash from SCR installations will have different characteristics, such as higher nitrogen content, and may have additional regulatory requirements and costs.

(3) Sulfur in coal and ammonia from the SCR can react to form ammonium bisulfate, which can plug air heaters. Other calcium and ammonium salts can foul the catalyst. The

commenter stated that the costs of these maintenance problems were apparently not considered in the proposal.

(4) The costs associated with storing large quantities of ammonia for the SCR were not adequately considered. Health and safety hazards and the potential for leaks will necessitate alarm systems and evacuation plans. Additionally, ammonia can cause "fogging" of photographic film, so SCR would be highly undesirable at film manufacturing sites.

(5) SCR requires significant open space for the catalyst bed. The commenter believed that newly constructed units could accommodate SCR through advance planning. However, for existing units located in dense industrial facilities, the lack of space presents a technical feasibility issue.

(6) The EPA did not consider the significant costs associated with handling and disposal of spent ammonia catalyst from SCR installations.

Commenter IV-D-45 also wrote that the EPA’s estimate that SCR would cost $2,000/ton was "significantly understated." The commenter explained that most paper mills have smaller sized and lower capacity boilers than electric utility units. These smaller boilers are expected to have a much higher cost per ton of NO_x reduction associated with SCR. The commenter stated that "the estimate of $2,000/ton is still too high to be considered cost-effective for control of a criteria pollutant like NO_x."

Commenters IV-D-26 and IV-D-61 did not agree with the cost-effectiveness values that the EPA calculated for NO_x control technology for coal-fired industrial boilers. The commenters cited a best control technology (BACT) analysis conducted by a State regulatory agency for a Prevention of Significant Deterioration Application written in 1992. Commenter IV-D-26 quoted the report to state: "in transferring SCR technology from the commercial applications in Japan to European sources, technical problems arose..." Commenters IV-D-26 and IV-D-61 quoted "it can be expected that almost every application will need to be verified in a pilot plant...Therefore, SCR is presently not considered technically feasible, and thus not BACT, for the proposed project." Commenter IV-D-26 summarized the following technical concerns that resulted from the 1992 BACT analysis:

(1) Catalyst costs are "over half of the operating and maintenance costs..."

(2) The reaction of SO_3 with ammonia to form ammonium bisulfate, which in turn can foul the catalyst and downstream equipment, and;

(3) The difference in coal characteristics between foreign and domestic coals.

In addition to the citations from the 1992 BACT analysis, Commenter IV-D-26 reported the following concerns with the EPA's own evaluation of the use of SCR for NO_X control for coal-fired industrial boilers.

(1) The Agency's analysis was based on seven coal-fired utility boilers with SCR in the Eastern United States only. The Agency did not demonstrate a solution on industrial boilers for all of the coal characteristics that will be encountered in the United States.

(2) Technologies utilized for utility boilers, especially multiple control devices that increase the risk of breakdowns, are not always directly transferable to industrial boilers. This is because of the different operating and maintenance practices between the two sources. Commenter IV-D-26 explained that the unplanned shutdown for a utility boiler can be managed by shifting the electric power generation to other available units of power, which

can be bought from a regional power grid. However, in the case of industrial boilers, the steam demand of the chemical manufacturing operation cannot be met, which results in shutting down the chemical operations and in considerable economic penalty.

Commenter IV-D-16 added that the EPA has not demonstrated anywhere that SCR or SNCR can be used cost-effectively with North Dakota lignite. The commenter recommended that the EPA not proceed with the rulemaking process until it can adequately demonstrate that SCR and SNCR technologies are cost effective with a variety of coals including lignite.

Commenter IV-D-53 stated that the cost-effectiveness value for coal units using SCR is calculated using a baseline NO_X emission rate of 0.45 lb/MMBtu, which in turn, “artificially inflates” the cost effectiveness of SCR for new coal fired units. The commenter stated that low NO_X burners can “easily meet” a 0.30 lb/MMBtu NO_X emission rate. The commenter recommended a higher emission standard in the range of 0.20 to 0.25 lb/MMBTU for all fuel sources.

Response: Several commenter’s said that the EPA’s cost estimates understated SCR costs and failed to represent the range of boiler conditions, particularly industrial boilers, in the U.S. The Agency is satisfied that the proposal cost analysis adequately represents the average nationwide costs to comply with BDT for new sources, and has not revised the analysis at promulgation. However, the Agency will take this opportunity to respond to the less-generic comments summarized above.

Commenter IV-D-47 speculated that the EPA extrapolated cost from an earlier study and did not account for all the capital costs of the SCR system. Please note that BID cost estimates were revised in a memorandum dated June 10, 1997 explaining that the costs were based on more recent information obtained by the

Acid Rain Division's cost estimates from their draft report entitled “Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers.” The EPA cost estimates for SCR used in the impacts analysis, and summarized in the preamble, were different than those used in the BID. The costs in the preamble and impacts memoranda (Docket Items, II-B-8, II-B-9, and II-B-10) were made using actual baseline emissions from the planned, new units in the country.

In response to the commenter who said that SCR is too energy intensive, the EPA notes that a detailed regulatory impact analysis was performed. The EPA believes that the energy impacts of SCR, which are only 0.4 percent of the boiler output, are justified.

The Agency offers the following response to address Commenters' IV-D-23 and IV-D-45 six items:

(1) The assertion that EPA based costs on a 5-year catalyst life is incorrect. The EPA used 3 years for coal-fired units.

(2) The Agency realizes that ash from SCR installations will have different characteristics (higher nitrogen content) and additional regulatory requirements and costs. The Agency did account for different types of coal, with varying ash contents, in the costing analysis.

(3) The Agency realizes that there are downstream effects from SCR. The cost estimates included indirect costs that accounted for these effects. Further, since proposal, the Agency has received cost estimates from two facilities with SCR that validate the Agency estimates. The indirect costs of SCR maintenance, ammonia and catalyst management were estimated to be approximately 1 percent of EPA's total SCR capital costs. (Memo to Project File, “Indirect SCR Costs.”)

(4) The additional storage costs for ammonia were considered in the indirect costs of SNCR and SCR. Because

anhydrous ammonia has been used safely for many years in the U.S. in a variety of industrial and agricultural applications, the EPA believes that any safety, environmental, or operational concerns can be fully addressed by proper planning and design of the ammonia handling system. These concerns are not a factor against adopting the emission limits that are based on SCR.

(5) This regarding space constraints is similar to Commenters' IV-D-19, IV-D-20, IV-D-26 and IV-D-65 comment about "scope adders" addressed above.

(6) Spent catalyst costs were also addressed in the indirect costs of SCR (BID for Subpart Db , page 6-11)

Commenter IV-D-26 raised concerns about the ability of industrial units to operate reliably when equipped with SCR and the resulting cost impacts of downtime due to control device malfunctions. While the Agency realizes that control devices do malfunction, and in fact, accounted for extra maintenance costs of SCR, both process and control device malfunctions are a fact of life in any complex operation. This is why many facilities are equipped with back-up or standby boilers. In the case of a malfunction, the NSPS provisions would not apply during the period of the malfunction, assuming the source acted to repair the malfunction as soon as practicable.

With respect to Commenter IV-D-16's comment regarding the use of SCR or SNCR with North Dakota lignite, the EPA’s cost estimates did project costs for lignite use and did not find its impacts different from the impacts of using different coal types. (Docket Item No. II-A-33.)

Regarding baseline emission rate, model plants used a higher emission rate (0.45.b/MMBtu), but the impacts analysis presented in the preamble used emission rates based on projected permit limits, which are lower. There is also a tradeoff in assuming a higher emission rate compared to a lower rate when looking at cost effectiveness. Higher baseline emissions would require a larger SCR and more catalyst, which would increase the cost side of the equation. Lower baseline emissions would require a smaller SCR, but would result in lower potential emission reductions from the controls.

Comment: Commenter IV-D-52 argued that EPA provided an inadequate basis for its conclusions, particularly the EPA's assumption that because gas- and oil-fired units are not expected to need SCR, it was not costed for these units. The commenter took exception to this assumption because “insufficient data is presented to warrant such assumptions and exclusions.” The commenter also stated that EPA must provide complete cost and performance models.

Response: As stated previously, the EPA is satisfied that the proposal cost analysis adequately represents the average nationwide costs to comply with BDT. Because gas and oil-fired units should be able to perform close to or at the NSPS emission limits (particularly in the case of industrial boilers) with low-NO_x burners or other combustion controls, the basis for the EPA’s statement in the preamble was the EPA’s assumption that these units would choose to either use SNCR to meet the limit or to simply improve the efficiency of their existing systems. The EPA did cost SNCR and SCR for oil- and gas-fired utility units in the proposal Background Information Documents, but since the EPA was implementing the philosophy of a "fuel neutral" approach the cost effectiveness calculations were conducted based on projected coal-fired steam generating units using coal.

3.4 OTHER COST ISSUES

3.4.1 Fuel Switching Costs

Comment: Commenter IV-D-23 noted that the costs of fuel switching were not analyzed in the proposal. The commenter estimated that natural gas costs more than twice as much as coal (on a Btu basis) when purchased on a "curtailment basis" (which favors residential customers over industrial customers during shortages). Natural gas supplied on a "non-curtailment basis" would be prohibitively expensive. The commenter advised the EPA that capital retrofit costs to accommodate a switch from coal to natural gas may be significant for some industrial units.

Response: The fuel neutral format of the proposed standards would allow for the use of natural gas, but would not require it in cases where the costs of using natural gas exceeded the costs of meeting the standard using alternative means, i.e., the application of SCR or other similar technology.

3.4.2 Energy Pricing

Comment: Commenters IV-D-24 and IV-D-42 noted that the EPA's economic analysis used an electricity rate structure with average costs because many corporations own multiple facilities. Both commenters agreed that with utility deregulation and restructuring in the near future, the averaging of costs over several facilities is outdated, unreasonable, and unacceptable. Additionally, Commenter IV-D-42 stated that "even if EPA's analysis were correct, that total annualized costs are 2.1-3.3 mills/kWh for SCR on a coal-fired unit, this does not justify requiring such technology based on cost."

Response: The Agency’s economic analysis used projected energy rates from the DOE’s Energy Information Administration for 1996 through 2000 to serve as the baseline and projected the incremental increase in electricity rates for each year to be equal to the weighted average of compliance costs across affected utility boilers. This national-level approach does not account for the more local nature of markets under regulated monopoly or deregulation. However, the uncertainty regarding which customers would be subject to higher rates and the future competition in electricity provision necessitated this national-level analysis.

In Section 5 of the RIA, the Agency states that its approach "will understate the expected increase in market prices under regulated monopoly and understate or overstate expected price increases for specific customers due to the use of average national price of electricity and measure of compliance costs." The total annualized costs from EPA's engineering cost analysis vary from 0.13 to 2.9 mills/kWh as compared to the projected national electricity price of 69.0 mills/kWh. Although beyond the scope of the economic analysis, the Agency does expect that price changes in local markets under regulated monopoly or deregulation will vary according to the actual costs incurred by the utility boiler servings these markets.

3.4.3 Proposed Standards Not Cost Effective

Comment: Commenter IV-D-48 noted that the incremental cost-effectiveness numbers for industrial, spreader-stoker coal-fired boilers with SCR and combustion controls versus combustion controls alone are exorbitant and totally unjustified. The commenter recommended that the standard be revised to impose limits which reflect demonstrated technology at a reasonable cost.

Commenter IV-D-26 quoted cost-effectiveness values for NO_x removal with SCR from a BACT analysis conducted in 1992 to be $11,541/ton of NO_x removed, as compared to the range quoted in Table 3 of the NSPS, which was $1,460-2,270. The commenter concluded that the costs of the SCR for NO_x control for industrial coal-fired boilers is currently not cost effective.

Commenter IV-D-61 stated that the docket does not support the EPA's conclusion that SCR is cost effective for coal-fired units. Table 4 (62 FR 36953) shows the range of cost effectiveness for SCR on industrial units as $0 - $4,800 per ton NO_x removed. The average is shown as $2,030. However, Table 3 (62 FR 36951) shows the range of cost effectiveness for coal-fired industrial units as $1,590 - $8,700 per ton. The commenter was unable to locate the basis for the ranges in Table 3. In the background document, *New Source Performance Standard, Subpart Db - Technical Support for Proposed Revisions to* NO_X *Standard*, Table C-1 shows a range of $2,780 - $29,950 per ton for incremental cost effectiveness for combustion controls and SCR versus combustion controls alone at coal-fired model boilers. The commenter noted that the values in Table 3 (62 FR 36951) appear to have been taken in error from the "Cost Effectiveness" column rather that the "Incremental Cost Effectiveness" column in Table C-1. The commenter also pointed out that the values in Table 4 (62 FR 36953) are based on an estimate of 381 new industrial units in the next 5 years, and that only 22 of these were projected to be coal-fired. Because the gas and distillate oil units would not have any control costs, the low average of $2,030 obscures the high costs incurred by the few coal-fired units.

<u>Response</u>: Commenter IV-D-48 listed as exorbitant all of the incremental cost-effectiveness (CE) numbers for industrial coal-fired boilers with SCR and combustion controls versus all the other possible control options. However, only the incremental CE of SCR with combustion controls versus combustion controls alone is relevant, because the baseline level of control is combustion controls. Therefore this scenario is the appropriate basis for comparison.

Commenter IV-D-26 compared the CE value from a 1992 BACT analysis conducted by a State agency to that calculated by the EPA for this NSPS revision. The EPA stands behind its original CE calculation and does not deem the CE to be exorbitant.

Commenter IV-D-61's report of being unable to locate the basis for the ranges in Table 3 is understandable. The EPA realizes that the derivation of the values in Table 3 of the preamble may not have been documented adequately for the proposal. The CE values summarized in Table 3 of the preamble originated from the impacts memo for subpart Db, Docket Item II-B-9, Table 8. The cost data in the BID Tables C-1 and C-2 are for the range of boiler sizes and capacity factors. The EPA determined that the capacity factor of 0.1 was too small for coal-fired boilers, therefore the cost-effectiveness values from all coal-fired boilers with this capacity factor were not used in the cost analysis or summarized in the Table 3 of the preamble.

Commenter IV-D-61's speculation that the numbers in Table 3 of the Preamble are the "Cost Effectiveness" values from the BID instead of the "Incremental Cost Effectiveness" values was incorrect, even though it may have appeared that way. The EPA used the overall CE numbers with the current NSPS level of control as the baseline.

Commenter IV-D-61 noted that the CE values in Table 4 obscure the larger coal CE values because they represent a smaller portion of the new boiler projections. The high numbers in Table 4 are CE values for oil-fired boilers where the CE values for coal-fired boilers are within the range listed in Table 4.

Comment: Commenter IV-D-31 stated that EPA addressed coal-fired power plants that use SCR technology for the cost analysis, but failed to acknowledge other high performance power plants that do not. The commenter cited the example of the Neil Simpson II unit, which is an 80-MW conventional boiler that has only low-NOx burners and achieved an output-based emission rate of 0.18 lb/million Btu in the second quarter of 1997. Commenter IV-D-31 calculated the cost effectiveness of the Neil Simpson II unit using the EPA's cost estimate and the operational data from the second quarter of 1997, which was extrapolated to one year. The commenter reported that "the results of this analysis showed that the incremental cost of reducing NO_X would be in the range of

$10,600 to $16,625 per ton. The commenter quoted the President's address on the Implementation of Revised Air Quality Standards for Ozone and Particulate Matter when he said: "It was agreed that $10,000 per ton of emission reduction is the high end of the range of reasonable cost to impose on a source."

Response: The EPA appreciates the data provided by the Commenter IV-D-31, however, the EPA did cost a comparably sized unit. In the National Impacts Memorandum, Docket item II-B-8, the EPA estimated the cost impacts of controlling NO_x emissions from an 80-MW boiler. The national impacts were calculated from actual facility data, and the NO_x emissions from this unit were controlled with SNCR. The EPA would not assume that SCR would be cost effective on such a small unit that is operating at low boiler outlet NO_x levels.

Comment: Commenter IV-D-31 stated that the cost effectiveness of NO_x controls on utility steam generating units is incorrect. The commenter explained that the NSPS represents a significant relaxation of standards from the NSR limits for natural gas units; therefore, there should be no incremental or annualized costs for these units. The commenter argues that the appropriate baseline for the cost analysis should be the NSR program, not the NOx levels being achieved with technologies to meet the current NSPS.

Response: The EPA used two different baselines in its analyses. In the model plant analysis the existing NSPS level of control was the baseline used. However, for the impacts analysis, the results of which are presented in the proposal preamble, the baseline limits used were current/expected permit limits, which were more stringent than the baseline limits used for the model plant analysis presented in the BID. Further, new units tend to have limits based on NSR decisions, and the EPA believes that the limits used for the impacts analysis reflect

NSR decisions in most cases.

4.0 REGULATORY APPROACH

4.1 APPLICABILITY

4.1.1 "No New Exemptions" Policy

Comment: Commenter IV-D-49 recommended that the rule "expressly state that [the] NSPS must be met in cases where a utility plant is transferred to a new owner." Commenter IV-D-49 referred to this concept as "no new exemptions." This recommendation was made in response to the deregulation of the electricity production industry. The commenter speculated that utilities will start to market electricity from "grand fathered" (preexisting, and therefore exempt from the NSPS) power plants to customers outside of their service territories, and, in some cases, sell entire power plants to other utilities or independent power producers.

Commenter IV-D-49 recommended that the EPA adopt a "no new exemptions" policy in two areas:

(1) The rule should require utilities to count all emission increases attributable to off-system sales when calculating increased emissions associated with a major modification. EPA currently exempts emission increases attributable to increased demand in a utility's service territory, because of the utility's obligation to serve. This rationale does not apply in the case of off-system sales, which are wholly discretionary. If a utility makes a major modification to upgrade a plant to sell power outside of its service territory, the costs of that decision should be borne by the utility's stockholders -- not the environment. Requiring such a utility to count all emission increases attributable to off-system sales as increased emissions would trigger the new NSPS for NO_x, thereby preventing the utility from externalizing at least some environmental costs associated

with power plant NO_x emissions.

(2) The rule should also expressly state that [the] NSPS must be met in cases where a utility power plant is transferred to a new owner. When a utility purchases a power plant from another utility -- as is happening with increasing frequency -- the power plant is "new" from the perspective of the new owner, and [the] NSPS should apply. In this type of situation, the new owner has a choice between purchasing a power plant or building a power plant. In the latter case, the plant would have to meet [the] NSPS. To exempt the former "new source" from [the] NSPS would be contrary to the express purpose of Title IV of the Clean Air Act, to reduce the adverse effects of NO_x emissions from fossil fuel combustion by implementing standards of performance that reflect improvements in methods for reduction of NO_x emissions.

Response: The Clean Air Act itself limits the scope of changes considered modification to “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” [Section 111(c)(4)] Section 60.14 of the Subpart A General Provisions provides additional guidance on EPA’s interpretation of this definition, and specifically excludes changes in ownership of an existing facility from being considered a modification. In addition, a key aspect to the definition of modification is that the change to the facility must result in an emissions increase. If the owner or operator can offset the increase, an NSPS modification is not established.

The commenter also noted that the EPA currently exempts emission increases attributable to increased demand in a utility's service territory, because of the utility's obligation to serve . The commenter said that this “exemption” should not apply in the case of off-system sales, which are wholly discretionary. The EPA believes that the guiding exemption is the ability of the source to increase its load in cases where: (1) the increase can be accomplished without a capital expenditure, (2) the increase results from an increase in the hours of operation of the facility, or (3) the use of an alternative fuel or other raw material takes place at a facility that was previously designed to accommodate the alternative use. None of these changes would be considered modifications.

4.1.2 NO_x Emissions Limits for Existing Boilers

Comment: Commenters 1, 4, IV-D-05, and IV-D-07 stated that the new source standards "do not address the overwhelming problem of NO_x emissions from utility power plants that were built prior to 1977." The commenter noted that these sources constitute 70 percent of the utility fossil fuel plants. Commenter IV-D-05 added that an emission reduction from these source as proposed in the NSPS would result in roughly a 75-percent reduction in NO_x emissions.

Commenter IV-D-50 recommended that the EPA explore how the current proposal can be interfaced with existing units, which operate with a wide range of efficiencies, have an extremely low retirement rate, and will continue to generate most of the electricity in the future.

Commenter IV-D-33 recommended that the output-based standard should be applied to all existing facilities. The commenter noted that output-based standards would promote economic development by removing market barriers for new generators. The commenter felt that an output-based standard combined with emission allowance trading mechanisms would ensure cost-effective emission reductions.

Response: The commenters’ suggestions are beyond the scope of this rulemaking. In any case, NOx controls developed under the acid rain program, the OTAG program, ozone SIP calls, etc. are all designed to specifically address existing sources.

4.1.3 Existing Sources Should Be Exempt from NSPS

Comment: Commenters IV-D-22, IV-D-32, IV-D-35, IV-D-47, IV-D-55, and IV-D-63 expressed opposition to the applicability of the NSPS to modified units. Commenters IV-D-32 and IV-D-63 both explained that in Section 111 of the CAA, "Congress was careful to limit the applicability of NSPS to sources that could be designed to include state-of-the-art pollution control technology." Commenters IV-D-32 and IV-D-63 continued by explaining that "NSPS were not made applicable to existing sources because Congress recognized the difficulty and expense of retrofitting control technology on such sources" adding that "the capital costs of retrofitting SCR at existing natural gas or coal-fired boilers are far more expensive than the costs of deploying SCR at new natural gas or coal-fired boilers." Commenters IV-D-47 and IV-D-55 agreed.

Commenter IV-D-41 said that the EPA was “acting unlawfully by failing to consider the costs that will be incurred by existing sources that become the subject of the proposed NO_x standard.” The commenter proposed that existing coal-fired sources are likely to become subject to this rule eventually, unless they are specifically excluded. If this occurs, the existing sources will be faced with excessive retrofit costs in order to attain the standard. The commenter added that because the proposed standards were not based on sound science, they conflicted “with principles adopted by the President and Vice President for Reinventing Environmental Regulation and endorsed through the Administrator’s Common Sense Initiative.”

Commenter IV-D-55 stated that “the installation of SCR on existing units... would be economically infeasible." A possible solution proposed by Commenter IV-D-55 was that the EPA propose a standard that modified units could meet without SCR, or justify the use of the same standards as for new units. Commenter IV-D-47 reasoned that "since EPA states that few modified sources will be affected, adding specific language clarifying that such units are not subject to the NSPS would raise few, if any, policy implications." Another possible solution presented was that the EPA specifically exclude modified boilers from the final NSPS.

Commenters IV-D-16 and IV-D-17 stated that modified coal-fired boilers should be explicitly excluded from the Subpart Da standard. The reason reported was because the capital costs of retrofitting SCR to an existing source is significantly more than applying the SCR technology to a new source. Commenter IV-D-17 quoted the EPA's estimate that it is 27 percent less expensive to outfit a new source compared to retrofitting an old plant.

Commenter IV-D-22 stated that the proposed NO_x emission limit was not demonstrated for non-gas-fired modified sources and that the new limit should not apply to sources that come under the NSPS through modification. In situations where liquid or solid fuel is fired, it is not always possible or reasonable to comply with the proposed limit. For instance, the commenter has a residual oil-fired boiler that could not be retrofitted to meet the proposed standard, and add-on controls would not be feasible because of limited space and unreasonable cost.

Commenter IV-D-35 wrote that the EPA claimed this was not a concern in the proposal. However, the commenter pointed out that EPA is aggressively pursuing businesses that have made efficiency improvements to force the units to meet NSPS under the modification provisions in 40 CFR 60. The commenter stated that the EPA "clearly has the discretion and duty to distinguish between new and existing sources which become subject to this rule."

Response: As described in the response to the comment under section 4.1.1, the General Provisions already provide several limitations to changes that might be considered modifications. For example, sources that offset their increased emissions are not subject to the NSPS because of modification. These provisions serve to effectively limit the application of the modification provisions to existing sources.

Section 111(b)(1)(B) of the Clean Air Act (the "Act") requires the Administrator to promulgate standards of performance for "new sources" in each category of sources which in the Administrator's judgment causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111(a)(2) of the Act defines "new source" to include stationary sources which are modified after an applicable standard of performance is proposed. The EPA finds nothing in the comments that would justify ignoring this clear statutory mandate. In developing standards of performance, section 111(a)(1) of the Act does, however, allow the Administrator to take into consideration the cost of achieving the required reduction and any nonair quality health and environmental impact and energy requirements. As noted at proposal, the efficiency of most existing electric utility steam generating plants ranges from 24- to 38-percent efficient. The EPA selected 38-percent efficiency as the baseline reflective of NSPS units. The EPA believes that selecting the 38-percent efficiency level for new electric utility steam generating units was an appropriate exercise of its discretion based on the available information. The EPA realizes, however, that existing units are likely to operate in the lower end of this range, with higher associated heat rates, which would make it more difficult to meet an output-based standard. These sources would have to compensate with higher control device performance (up to a 40-

percent increase in performance), which would be more costly. As a result, as discussed below in section 5.2.2, the EPA will allow existing units that become subject to the NSPS because of modification or reconstruction to meet an equivalent input-based standard of 0.15 lb/MMBtu. This change will eliminate the concern that lower boiler efficiencies at existing units could adversely affect a source’s ability to meet an output-based standard. This level of control represents the same overall level of SCR performance that would be required of new units, but lacks the benefits attributed to promoting energy efficiency that the output-based format provides.

Comment: Commenter IV-D-42 expressed concern that the current NSPS, new source review (NSR), and prevention of significant deterioration (PSD) programs punish unit owners for improving the efficiency and performance of existing units. The commenter pointed out that if a coal-fired unit changed burner systems to improve heat rate and annual availability, the owner could be subject to NSR, technology analysis, preconstruction delays, administrative costs, potential emission control upgrades, emission offsets, and compliance with the proposed NSPS limit. The commenter proposed that the EPA "couple the current NSPS proposal for an efficiency-based standard with an enforceable policy that physical changes to existing fossil-fuel-fired steam generating units which result in a reduction in the lbs/MWh of pollutant emissions would not trigger NSR or PSD." The commenter would support the efficiency-based standard if efficiency upgrades for existing units were not penalized.

Response: A reduction in maximum hourly emissions would not trigger the NSPS modification provisions. As for applicability under NSR, the applicability criteria for utility boilers as well as for other sources is the subject of an ongoing NSR rulemaking, which was proposed on July 23, 1996 (see 61 FR 38250). The comment period for that rule has closed, and the final rulemaking will address the issue of NSR applicability for utility boilers and other sources.

4.1.4 Modification Criteria

Comment: Commenter IV-D-06 noted that, in the applicability exemptions to the rule, "no mention is made of routine maintenance, repair and replacement." The commenter explained that the routine replacement of boiler steam tubes may result in increased efficiency. This increased efficiency may increase the heat input capacity, and the hourly emissions, given the same emissions rates. The commenter asked if this change would make the boiler subject to the revised NSPS as a modification.

Response: The EPA, upon request, will determine the rule's applicability on a case-by-case basis in accordance with the requirements of sections 60.14 and 60.15 of the part 60 General Provisions.

4.1.5 Applicability in NO_x Attainment Areas

Comment: Commenter IV-D-59 said that the new emission limit is not needed in portions of the United States that already comply with current air standards for NO_x. Commenter IV-D-59 concluded that, in certain regions of the United States, the proposed limits "do not result in any improvement in air quality." Further, the commenter stated that the proposed rule would penalize units which already "pay a production penalty due to the installation of the same control equipment."

Response: The NSPS program is intended to be a national program that serves, in part, to "level the playing field" between similar sources and to contribute to nationwide attainment (and maintenance of attainment) of the criteria pollutants, of which NO_x is one. In addition, in revising the National Ambient Air Quality Standards (NAAQS) in July 1997, the Agency recognized the regional role that NO_x emissions play in ozone formation.

4.2 FUEL NEUTRAL APPROACH VERSUS SUBCATEGORIZATION

4.2.1 Support Fuel Neutral Approach

Comment: Commenters 1, IV-D-05 and IV-D-07 supported a cap on NO_x emissions at the same level for nearly all fuel types. Commenters IV-D-05 and IV-D-07 reasoned that this allows fuel switching as a control technology. Commenter 1 added that it was an "important and positive step toward cleaner air ... across the nation."

Commenters 4, IV-D-20, IV-D-25, IV-D-29, IV-D-44 and IV-D-46 also expressed support for the proposed fuel neutral standard. The commenters stated that currently, natural gas-fired units are subject to the most stringent standard while coal and residual oil are allowed to emit much larger quantities of NO_x. The proposed rule will remove the disincentive toward natural gas that has been created. One commenter wrote that a fuel neutral standard would not penalize any particular industry, but would encourage competition for new efficient boilers and cogeneration units, and would be consistent with the EPA's emphasis on pollution prevention.

Commenter IV-D-50 generally supported the fuel neutral proposal because it "provides a level playing field for different fuels and promotes the use of natural gas and clean oil-based fuels, while at the same time it avoids unnecessary burdens on coal-fired units." Commenters 4 and IV-D-29 added that a uniform emission limit is needed to encourage fuel switching as a control option.

Response: The Agency appreciates the commenters’ support.

4.2.2 Oppose Fuel Neutral Approach

Comment: Commenters IV-D-17 and IV-D-31 opposed the same NO_x emission limit for all fuel types because “EPA’s proposal sets a lower than lowest achievable emission rate (LAER) level for coal-fired boilers, while significantly relaxing standards for natural gas units by a factor of two to four times.” Commenter IV-D-31 noted that BACT for coal-fired boilers is currently about 0.23-0.25 lb NO_X/MMBtu, and LAER is about 0.15 lb/MMBtu; whereas the proposed standard appears to be 0.13-0.14 lb/MMBtu. Further, for natural gas units, BACT is currently around 0.07-0.08 lb/MMBtu and LAER is on the order of 0.03 to 0.04 lb/MMBtu.

Commenter IV-D-50 noted that the EPA is requiring much less stringent control for gas- and oil-fired units. The commenter pointed out that a number of gas- and oil-fired units in the U.S. currently achieve approximately one-tenth of the proposed limit with the application of SCR.

Commenters IV-D-16, IV-D-24, IV-D-28, IV-D-56 and IV-D-61 stated that the "proposal violates the Act by providing an overwhelming incentive for new and modified electric generating units to burn natural gas to the exclusion of coal." Commenter IV-D-56 continued by stating that "the plain purpose of the percent reduction requirement was to protect Appalachian and Midwestern high sulfur coal...by requiring all new modified coal-fired units to be scrubbed." Further, Commenter IV-D-56 reported that the SO_2 allowance trading program created by the 1990 Amendments was intended in part to create flexibility for sources to continue to use high sulfur coal..." Commenter IV-D-56 recommended that the EPA withdraw the proposal.

Commenter IV-D-24 pointed out that "a varied mix of energy sources should be supported for the stability of the U.S. generation system." The commenter stated that coal use should not be discouraged, and that natural gas could meet a NO_X limit lower that those for other fuels.

Commenter IV-D-61 expressed opposition to the fuel neutral approach because of fuel availability and cost factors. The commenter noted that the natural gas industry has not adequately supplied areas of the U.S. that have an abundant supply of coal. The commenter stated that natural gas is not uniformly distributed and evenly available to all industrial users. The commenter asserted that the proposed emission limit "favors industrial development in regions that have an ample supply of natural gas and penalizes regions that have no practical option for steam production at industrial facilities other than coal."

Commenter IV-D-59 said that the fuel neutral emission rate may inadvertently be a dis-benefit to the introduction of low NO_x technology. The commenter postulated that “the result then might be continued operation of older more polluting sources than might otherwise occur.”

Response: The EPA disagrees with the commenters who contend that the proposed fuel neutral format creates an overwhelming or disproportionate incentive to use fuels other than coal. The EPA’s approach is designed to allow the continued use of coal as a fuel in those cases where it is desirable. At the same time, the standard would not preclude conversion to natural gas where it makes sense in the individual application.

The EPA believes the fuel neutral approach would expand the control options available to owners and operators by allowing the use of clean fuels as a method for reducing NO_x emissions. Since projected new utility steam generating units are predominantly coal-fired, the use of clean fuels (i.e., natural gas) as a method of reducing NO_x emissions from these coal-fired steam generating units may give the regulated community a more cost-effective option than the application of SCR for meeting the NO_x limit. Similarly, for industrial units, the use of clean fuels as a method of reducing emissions may be a cost-effective approach for coal-fired and residual oil-fired industrial steam generating units.

The fuel neutral approach also fits well with section 101(a)(3) of the Clean Air Act's emphasis on pollution prevention, which is one of the EPA's highest priorities. Because natural gas is essentially free of sulfur and nitrogen and without inorganic matter typically present in coal and oil, SO_2, NO_X, inorganic particulate, and air toxic compound emissions can be dramatically reduced, depending on the degree of natural gas use. With these environmental advantages, gas-based control techniques should be viewed as a sound alternative to flue gas treatment technologies for coal or oil burning.

Finally, the proposed amendments do not relax the existing NSPS for natural gas units. In fact, the 0.15 lb/million Btu heat input reflects a 50- and 25-percent reduction in NO_X emissions over the current Subpart Da limits for oil-fired and gas-fired units, respectively. Revised Subpart Db would not require any additional controls for new gas-fired and distillate oil-fired units over the current NSPS because of the costs associated with additional controls. However, subpart Db does not relax the existing standards for these units either. Historically, projections for new utility boilers have tended to be for coal-fired units. Stricter NO_X controls for gas might make co-firing less attractive, while a fuel neutral approach facilitates adoption of some natural gas firing, which has environmental and other benefits over straight coal-burning units.

4.2.3 Distinguish between Classes, Types and Sizes

Comment: Commenter IV-D-17 recommended that the EPA establish separate standards for coal-, oil-, and gas-fired units. The commenter noted that EPA has subcategorized utility boilers by fuel type in all previous NSPS for NO_x. The commenter stated that EPA has chosen to ignore differences between categories of sources. The commenter voiced concern that the proposed standard will result in a bias toward natural gas in electric generation, which could be a risk considering supply and availability factors. Additionally, the commenter did not agree with establishing a standard that "stretches one source category (coal) to the limits of economic efficiency, while requiring little from the other source categories (oil and gas)."

Commenters IV-D-47, IV-D-52, and IV-D-63 asserted that the EPA has not justified its decision to abandon fuel specific standards in favor of the fuel neutral approach. The commenters noted that there was "little discussion or analysis concerning cost, feasibility and other issues regarding the subcategorization of types of coals." Commenter IV-D-47 noted that the EPA's Regulatory Impact Analysis did not consider any option that would have subcategorized types of coal, or any control technology other than SCR. The commenter stated that "Because Congress gave EPA discretion to subcategorize on the basis of fuel type, and because EPA has previously determined that subcategorization is necessary to satisfy the §111 decision making criteria in the case of NO_X standards for utility boilers, the Agency has an obligation to explain why it has decided to reject its prior rulemaking conclusions that subcategorization is necessary to satisfy the §111 statutory criteria."

Commenters IV-D-38 and IV-D-52 noted that the proposal did not distinguish between classes, types and sizes within categories. Commenter IV-D-52 stated that the approach taken is counter to all previous NSPS rulemakings for NO_X, and requested that the EPA explain why.

Commenter IV-D-35 stated that the EPA has not justified the rationale for not creating subcategories among coal-fired units based on fuel sulfur content.

<u>Response</u>: Past regulatory approaches were based on boiler modification techniques, which made fuel selection more closely

related to performance compared to the post-combustion control techniques that comprise the currently proposed subparts Da and Db. The performance characteristics of the SCR technology do not justify the creation of subcategories based on sulfur content of coal (although the EPA has revisited some of the cost analyses related to the catalyst life issue, see section 3.3.). Section 111(b)(2) of the Clean Air Act allows the Administrator to distinguish among classes, types and sizes of sources, but does not require the Administrator to do so. As discussed elsewhere, the EPA does not believe that the format of the proposed rules creates a bias in the use of natural gas in electrical generation, but rather, provides owners and operators with additional flexibility in meeting the NO_x limit.

4.3 PROMULGATION SCHEDULE AND COORDINATION WITH ICCR

Comment: Commenter IV-D-30 expressed opposition to any further delays in the promulgation and implementation of the proposed NO_x NSPS. The commenter pointed out that "EPA should have promulgated this NO_x NSPS over 3 years ago and further delays at this time are unjustified." The commenter urged EPA to adopt the proposed revisions as soon as possible in order to achieve needed reductions in NO_x emissions from all sectors.

Commenters IV-D-30 and IV-D-62 stated that "EPA should not delay the implementation of the proposed NO_x NSPS in order to coordinate it with other ongoing actions such as the Industrial Combustion Coordinated Rulemaking (ICCR) process." Commenter IV-D-30 speculated that the NSPS could be used as a NO_x benchmark in the ICCR process when establishing the MACT floor.

In contrast, Commenter IV-D-47 noted that Executive Order 12866 directs regulatory agencies to "avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations." Combined cycle units emit NO_x from a combustion turbine and a duct burner. At this time, the combustion turbine emissions are regulated by NSPS Subpart GG, while the duct burner emissions are regulated by Subpart Da or Db. The commenter stated that it would be difficult for combined cycle units to show compliance with the proposed output-based Subpart Da standard. The commenter noted that the ICCR is considering revising Subpart GG. The commenter urged the EPA to "undertake a separate rulemaking that results in a single rule that regulates all NO_X emissions from such units."

Commenter IV-D-26 explained that the ICCR committee was established to coordinate the rulemaking for industrial-commercial-institutional combustion sources under Section 111, 112 and 129 of the Clean Air Act. The commenter stated that the proposed NO_X was drafted outside of the ICCR process, and recommended that the EPA determine how the modified NSPS will impact the ICCR process and whether the ICCR should alter the scope of its rulemaking.

Commenters IV-D-45 and IV-D-48 recommended that the proposed Subpart Db NO_X NSPS should be combined with the EPA's ICCR procedure. Commenter IV-D-61 recommended that the NO_X NSPS proposal for industrial-commercial-institutional boilers should be withdrawn and considered as part of the ICCR. If the EPA issues the proposed NSPS and the ICCR analysis results in a proposal that would be different, the EPA would have to revise the NSPS again. "This would cause the regulated community undue hardship in trying to comply with multiple and possibly differing control requirements."

However, Commenter 3 stated that the industrial portion of the NO_X NSPS should not be included within the ICCR and gave six reasons:

(1) It is not appropriate for either the U.S. EPA or the ICCR to attempt to circumvent the court-ordered deadlines by using the ICCR as an excuse.

(2) NO_x reductions are needed from all sectors, including nonutility units, as soon as possible in order to reduce the current ozone problem...

(3) The EPA has already performed an adequate analysis of the impact of the proposed NO_x NSPS on a source's ability to control other air pollutants.

(4) The EPA has already performed an adequate cost analysis on the cost impacts of the rule for both utility and nonutility units and has already proposed to substantially reduce the cost impact for new industrial steam generating units, by about 70%, by proposing NO_x emission limit at 0.20 lb/million Btu rather than 0.15 lb/million Btu.

(5) The proposed NSPS can be used by the ICCR boiler workgroup as a NO_x benchmark when establishing the MACT floor and therefore need not conflict with any of the work already performed by the ICCR.

(6) The simplest way to avoid any conflict between the proposed NO_x NSPS and the ICCR Boiler Workgroup's work is to accept the proposed NO_x NSPS as the NO_x emission limit for fossil fuel-fired boilers when establishing the MACT floor for these units.

Response: The EPA is under a court-ordered deadline to promulgate revisions to the NSPS by September 1998. The July 1997 promulgation of revisions to the ozone NAAQS lends increasing urgency to the development of national standards and other tools that will assist the States in developing implementation plans to meet the new standards. The NO_x NSPS revisions are one such tool that would be used by the States in their attainment planning. However, the EPA agrees with commenters that the outcome of the NSPS should be considered in the ICCR process.

The EPA agrees that ICCR-driven revisions to subpart GG, standards of performance for stationary gas turbines, pose a potential conflict with the subparts Da and Db standards, if they extend the applicability of subpart GG to the duct burner, which is currently covered by subparts Da and Db. Therefore, the EPA will revise subparts Da and Db to exempt sources that may also become subject to subpart GG, should such revisions to subpart GG occur.

4.4 OVERALL MONITORING, REPORTING, AND RECORDKEEPING REQUIREMENTS

Comment: Commenter IV-D-01 noted that small units (maximum heat input of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr) subject to Subpart Dc have no NO_x limit, monitoring or recordkeeping requirements. The commenter recommended NO_x requirements that are intermediate to those of Subpart Dc (none) and the current requirements of Subpart Db (extensive) for low emitting units subject to Subpart Db.

Response: The EPA believes the current Subpart Db requirements are the minimum needed to ensure compliance with the standard. However, owners or operators of low-emitting boilers subject to the requirements of this rule may petition the U.S. EPA Regional offices for alternative monitoring methods, according to section 60.13(i) of the part 60 General Provisions. The EPA will consider these petitions on a case-by-case basis.

Comment: Commenter IV-D-21 recommended that language be added to 40 CFR Part 60 to "exempt from measuring and reporting gas- and/or oil-fired boilers that currently meet any state or local NO_x emission standard that is equivalent to or more stringent than the federal regulation."

Response: Since State and local regulations are usually not Federally enforceable, EPA regulations must be enforced. If the State/local regulations are more stringent than the applicable EPA regulations, the affected facilities may individually petition the EPA for relief under the alternative monitoring provisions. Alternatively, Title V streamlining can coordinate the State and Federal requirements.

5.0 ESTABLISHING OUTPUT-BASED FORMAT FOR UTILITY BOILERS

5.1 OVERALL APPROACH

5.1.1 Support Output-Based Format

Comment: Several commenters (1, 4, IV-D-05, IV-D-07, IV-D-18, IV-D-19, IV-D-20, IV-D-25, IV-D-27, IV-D-29, IV-D-33, IV-D-34, IV-D-39, IV-D-42, IV-D-43, IV-D-44, IV-D-46, IV-D-49, IV-D-50, IV-D-51, IV-D-54, IV-D-60, and IV-D-65) expressed support for the output-based format of the proposed standard. These commenters indicated that the output-based format would reward energy-efficient generators.

Commenter IV-D-39 cited the use of the following design options to improve efficiency: air or water preheaters, economizers, fans, and/or heat exchangers. The commenter added that it is “common today for boiler efficiency to deteriorate over the life of the unit, and the efficiency calculation would ensure that the operator properly maintained the unit."

Response: The EPA appreciates the commenters’ support.

5.1.2 Oppose Output-Based Format

Comment: Commenters IV-D-11, IV-D-17, IV-D-32, IV-D-36, IV-D-37, IV-D-47, IV-D-53, and IV-D-63 opposed the output-based format noting the following reasons:

(1) The incentives to be efficient have recently increased due to the newly competitive nature of the industry, and will continue to increase without output-based standards.

(2) The format would add significant burdens to an already complicated monitoring system for utilities.

(3) There are inconsistencies between the proposed NSPS output-based format and the following input-based regulations also applicable to these sources: existing boilers NO_x units, sulfur dioxide and particulate matter limits, electric generating units under NSPS Subpart D,

existing regulations implementing reasonable available control technology (RACT) for NO_x in ozone non-attainment areas, proposed NO_x limitations for states included in the Ozone Transport Assessment Group (OTAG), and the NO_x Emission Reduction Program under 40 CFR 76, and Section 407 of the Acid Rain Program requires output-based reporting.

(4) NO_x averaging of NSPS units with existing units would be very complicated.

(5) The output-based format is inappropriate and inaccurate for cogeneration facilities that produce steam in addition to or in place of electric generation. The commenter explained that customers dictate the temperature and pressure conditions of the steam that is produced. The generator has no choice and must produce the desired product. The commenter indicated that the EPA method of equating steam production to electric production was over-simplified and punitive in that it does not consider all of the potential steam production conditions. The commenter reported that this would increase the cost of efficient cogeneration. The commenter concluded that the input-based standard is more appropriate, fair, and environmentally protective.

(6) An output-based NSPS does not promote energy efficiency because it "makes no allowance for the use of low Btu fuels (such as waste coal) that would otherwise go unused...By encouraging consumption of less expensive low Btu fuels, the EPA would promote generation of electric power at costs below those presently realized." Commenter IV-D-36 added that not "penalizing" utilities for burning low Btu fuels would promote discovery and utilization of these fuels, and thereby contribute to national energy self-sufficiency. Further, commenter IV-D-36 argued that the proposed NSPS "is

not keeping with recent utility deregulation," because "an important goal of recent utility de-regulation was to allow market forces to minimize the cost of electric power to consumers, without eroding environmental protection."

(7) The EPA's proposal should encourage consumption of low-cost fuels.

Response: The EPA continues to believe in the benefits associated with an output-based standard for new sources that encourages energy efficiency. The changes in the output-based format, discussed below in section 5.2, will simplify the compliance demonstration for sources by eliminating the need to convert input values to output values. While, the EPA is concerned about apparent inconsistencies in monitoring requirements associated with various programs to which individual sources might be subject, the EPA also feels that the requirements of the NSPS stand on their own merits. The NSPS provisions do not require any additional monitoring at sources beyond what is already required by the Acid Rain program. In some instances, the Title V permit process and activities such as permit streamlining may provide relief to sources on a case-by-case basis. In addition, the EPA will continue to explore additional ways to provide monitoring relief that do not compromise the ability of EPA to adequately enforce Federal standards.

As discussed below in section 5.2.5, the EPA did examine possibilities to revisions to the steam credit allowance for co-generation facilities. These issues are further addressed in that section.

Finally, the EPA believes that low-cost fuels can be used effectively at facilities subject to the final standards. As discussed, the U.S. Generating Company’s Northampton facility is currently performing better than would be required under the amended NSPS and uses waste coal as its sole energy source.

5.2 INPUT TO OUTPUT CONVERSION ASSUMPTIONS

The EPA has decided to revise the compliance demonstration for affected sources, based on analysis of comments submitted on the input to output conversion assumptions. As discussed in detail in this section, the EPA will finalize the standard for new sources at a level of 200 ng/J (1.6 lb/MWh) gross energy output. This change incorporates concerns related to overall heat rates, steam credits for cogeneration facilities, and gross versus net output. In addition, the key underlying assumption inherent in the selection of the level of the final standards at 200 ng/J (1.6 lb/MWh) gross output, i.e., the input-based standard of 0.15 lb NO_x/million Btu, is maintained. The effect of this change is that sources would no longer be required to calculate output emissions based on a measurement of input converted to the output format. The EPA believes this change will be simpler for sources to comply with and for enforcement agencies to monitor compliance.

5.2.1 Support the 38-Percent Baseline Efficiency

Comment: Commenters IV-D-34, IV-D-50, and IV-D-54 noted that the application of a baseline efficiency factor was an appropriate means of establishing the output-based limit. Commenters IV-D-18, IV-D-34, IV-D-50 and IV-D-54 stated that the 38-percent efficiency factor was reasonable.

Commenter IV-D-20 did not challenge the EPA’s selection of 38-percent efficiency for new boilers, corresponding to a heat rate of 9,000 Btu/kWh. However, the commenter believed that EPA should be consistent and "choose a representative, sustainable heat rate for new boilers after 5 years of operation."

Response: As discussed below, the selection of a baseline efficiency value is intimately tied to the selection of a corresponding heat rate. Based on information received by commenters, the EPA has decided to revisit the heat rate issue.

5.2.2 Oppose the 38-Percent Baseline Efficiency

Comment: Commenters IV-D-19 and IV-D-65 stated that the EPA adoption of a single heat rate was indefensible. The commenters remarked that the EPA "had ample time" to convert each boiler's input-based emission data to an output-based emission rate. Further, the commenters noted that the EPA "must be careful in choosing the single heat rate factor for conversion;" adding that "merely picking a 38 percent efficiency based on anecdotal evidence is not sufficiently rigorous."

Response: As discussed below, the EPA has used information provided in the public comment period to reevaluate its assumptions regarding the underlying assumptions in the output conversion equation. We believe our analysis is adequate and sufficient to demonstrate the feasibility of the final approach.

Comment: Commenter IV-D-36 stated that "the proposed NSPS defines a NO_x emission limit that is a function of NO_x emission rates and plant-wide thermal efficiency and in so doing, favors water-cooled condensers over air-cooled condensers." The reason is that "the air-cooled heat rejection systems are inherently less thermally efficient than water-cooled systems." The commenter explained that in the western United States water is at a premium, adding that the "best allocation of water resources in these areas does not always include water-cooled power plants." The commenter recommended that "some allowances must be made," and offered the possibility of second equation for air-cooled units, "replacing the assumed 38-percent thermal efficiency in the current equation with a representative air-cooled efficiency (probably in the order of 31 percent)."

Response: The proposed output-based standard has been revised to 1.6 lb/MWh gross output. This standard corresponds to a gross heat rate of 10,667 Btu/kWh and a gross thermal efficiency of 32 percent, which should satisfy the commenter's concerns about air-cooled units.

Comment: As discussed in section 4.1.3., several commenters were concerned about the ability of existing boilers to comply with the NSPS should they become affected sources through modification or reconstruction.

Response: The EPA agrees with the concerns raised by commenters that the inherent efficiencies of existing boilers may be less than the efficiency that new boilers are capable of achieving. Lower boiler efficiency translates to higher average heat rates, which would make it more difficult for existing sources to meet an output-based standard without increasing SCR performance significantly (up to a 40 percent improvement could be required.) Therefore, the EPA has revised the final rule to allow existing boilers that might become subject to the NSPS through modification or reconstruction to meet an equivalent input-based standard of 65 ng/J (0.15 lb/MMBtu). This level of control represents the same overall NO_x reduction efficiency that would be required of new units, but lacks the benefits attributed to promoting energy efficiency that the output-based format provides. The actual environmental impact of the change should, therefore, be negligible.

5.2.3 Support Net Heat Rate of 9,000 Btu/kWh

Comment: Commenter IV-D-50 supported the EPA's assumed "baseline" efficiency of 38 percent, which corresponds to a heat rate of 9,000 Btu/kWh. The commenter noted that most U.S. boiler heat rates range from 9,000 to 13,000 Btu/kWh. Because the intent of the EPA is to encourage efficiency, the 9,000 Btu/kWh heat rate is appropriate.

Response: As discussed below, the EPA has reconsidered the heat rate assumption, based on data obtained by the EPA since proposal and received from commenters.

5.2.4 Oppose Net Heat Rate of 9,000 Btu/kWh

Comment: Commenters IV-D-17, IV-D-19, IV-D-27, IV-D-28, IV-D-37, IV-D-47, IV-D-52, IV-D-53, and IV-D-65 questioned the proposed heat rate standard of 9,000 Btu/kWh. The commenters stated that the “proposal fails to provide necessary discussions justifying the selection of the highly restrictive baseline threshold of 9000 Btu/kW-hr.” Further, Commenter IV-D-52 recommended that the EPA review all available heat rate data for U.S. utilities, and reconsider applicable modifications to the proposed baseline...” One commenter noted that the rate may be appropriate for gas-fired combined cycle units, but would discourage the use of coal and waste coal. Commenter IV-D-37 specified that heat rates in the 9,000 Btu/kW-hr are typically limited to those operating at supercritical steam pressures and temperatures along with combined cycle gas turbine (CCGTs) units. Commenter IV-D-37 continued by stating that "because many Da units are subcritical and fire solid fuel, imposition of a one-size-fits-all net efficiency constitutes a bias against these types of units."

Commenter IV-D-28 stated "the only type of solid fuel facility that could meet a low heat rate standard of 9,000 Btu would be a huge (1,000 MW) super critical coal unit with extremely high operating temperatures. Small waste coal facilities with circulating fluidized bed boilers could not meet this standard." Commenter IV-D-55 elaborated by stating that one of their pulverized coal-fired utility power plants has an average net heat rate of 9,808 Btu/kWh. Commenter IV-D-27 stated that their coal burning facilities are state-of-the-art from an emissions standpoint, and operate at heat rates of up to 11,000 Btu/kWh. This figure agrees with conceptual designs for a future coal-fired plant, which assumed heat rates of 9,900 to 13,757 Btu/kWh. The commenter stated that these data suggest that an output-based standard of 1.35 lb/MWh is equivalent to an input-based standard of 0.1 to 0.137 lb/MMBtu, not 0.15 lb/MMBtu as assumed by the EPA.

Commenter IV-D-53 reported that the net heat rate for new coal fired generation will fall in the range of 9,400 to 9,600 Btu/KWh at full load, 9,600 to 11,000 Btu/KWh at mid load and over 13,000 Btu/KWh at minimum load. The commenter recommended a baseline efficiency of 10,500 Btu/KWh. Commenters IV-D-17, IV-D-47 and IV-D-37 stated that, assuming one typical heat rate is appropriate, an analysis of data from Subpart Da boilers indicates that a heat rate of 10,500 Btu/kWh would be more appropriate, whereas Commenter IV-D-27 recommended a heat rate of 10,000 Btu/kWh. This would result in an output-based limit of 1.58 lb NO_x/MWh for the 10,500 heat rate and 1.5 lb/MWh for the 10,000 Btu/kWh heat rate.

Commenters IV-D-16 and IV-D-63 stated that there is no data by EPA to show a 9,000 BTU/kWh heat rate can be obtained.

Response: The proposed heat rate was a major concern of both commenters and the EPA. In light of additional data supplied by commenters and collected by EPA, the EPA has decided to revise the assumed heat rate. First, the output-based standard is now based on gross output instead of net output, so the following discussion will be in terms of gross heat rates. The decision to switch from net to gross output is discussed in section 5.3.

The commenters indicated that net heat rates of 10,000 to 10,500 Btu/kWh are typical of state-of-the-art units. The EPA collected data from four additional utility boiler that are considered to be new and state-of-the-art from an emissions standpoint. The first boiler was a base-loaded, fluidized bed combustion cogeneration unit that fired waste coal and was equipped with SNCR (Northampton). This unit's average gross heat rate (with 50 percent credit for export steam) was less than 9,000 Btu/kWh. The second unit was a pulverized coal-fired, cogeneration unit that operated under cycling load and was equipped with SCR (Logan). This unit's average gross heat rate (with 50 percent credit for export steam) was approximately 10,250 Btu/kWh. The third utility boiler (Stanton) had an average heat rate of 10,250 Btu/kWh. The Birchwood cogeneration unit, the fourth facility, reported that they cycle between heat rates of approximately 10,700 Btu/kWh at 32 percent load and 9,000 Btu/kWh at 100 percent load. The heat rates reported by the Birchwood cogeneration unit are based on a 100 percent credit for export steam.

The EPA conducted statistical analyses in which the objective was to assess long-term NO_x emission levels, on an output basis, that can be achieved continuously. Statistically, Logan, Northampton, and Birchwood can meet the revised output-based standard of 1.6 lb/MWh (gross) on a 30-day rolling average.

5.2.5 Efficiency Calculation for Cogeneration Units

Comment: Commenters IV-D-18, IV-D-19, IV-D-34, IV-D-39, IV-D-44, IV-D-53 and IV-D-65 asserted that using only 50 percent of the thermal energy from the steam generated at cogeneration facilities in calculations of output-based emission rates is inappropriate. The commenters reported that the 50-percent allocation is from a section of the Public Utility Restructuring Policy Act (PURPA) in which the 50-percent thermal output is used as part of a definition of a PURPA-qualifying facility. Further, the commenter stated that the calculation should use either the electric output converted to MMBtu plus the enthalpy of the full steam or hot water output in MMBtu, or the electric output in MWh_{el} plus the enthalpy of the full steam or hot water output in MWh_{th}. Further, Commenter IV-D-39 reported that the efficiency of new industrial boilers typically ranges from 78 to 83 percent depending on fuel and other design features. The commenters reasoned that each application would differ in efficiency, and credit should be given for the heat actually used. Commenters IV-D-19 and IV-D-65 added that the restriction of the steam credit to 50 percent is “arbitrary and capricious.”

Commenters IV-D-20, IV-D-44, and IV-D-46 supported the output-based standard and stated that the "appropriate output measure for industrial boilers would be pounds of NO_X per million Btu of steam produced at the boiler steam header." The commenters saw no reason to penalize cogeneration units by calculating output as electric output plus 50 percent of the thermal output, as suggested by EPA. The output calculation should give full value to the steam produced. Output from a cogeneration unit should be measured as the electric output plus the full thermal output in consistent units.

Commenter IV-D-46 said that "the output for a cogeneration facility should be the electric output and the full thermal output expressed in consistent units (MWh or MMBtu) where 1 kWh = 3413 Btu."

Commenters IV-D-39 and IV-D-46 insisted that efficiency should not be used as a compliance measure. The commenter explained that the efficiency calculation is an extra, unneeded step. The commenters reported that all that is needed is a continuous emission monitoring system (CEMS) to directly measure NO_X and an electric or thermal measurement for output in units of MMBtu or MWh.

<u>Response</u>: The EPA considered three approaches to resolve the issue of steam credit for cogeneration facilities: 1) Allow credit for steam as if it were being converted into electricity; 2) Allow credit in the form of 50 percent of the thermal value (enthalpy) of the steam; and 3) Allow credit for greater than 50 percent of the value of the steam, up to 100 percent.

The EPA decided not to allow credit for steam as if it were being converted into electricity because the EPA wants to encourage cogeneration. Allowing credit as if electricity would only provide credit for up to 38 percent of the value of the steam, which is the reported maximum of the efficiency of steam to electricity conversion.

The EPA also decided not to allow for greater than 50-percent credit for the steam. Based on analysis of heat rates from cogeneration facilities, the EPA has determined that once you exceed 50 percent and approach 100 percent credit for the steam there is a disproportionate lowering effect on heat rate, particularly at high steam export rates. This would result in artificially low NO_x emission rates. As another option, the EPA considered allowing 100 percent credit for steam, but capping the amount of steam for which credit could be received to a certain percentage of total output. This approach was deemed to be too complex from a monitoring standpoint.

Therefore, the EPA has decided to retain the proposed 50-percent credit for export steam from cogeneration facilities on the basis that it encourages cogeneration, will not artificially lower NO_x emissions, and will not require complex monitoring.

Comment: Commenter IV-D-39 reported that steam metering has been well established, especially for companies that sell thermal as well as electric energy. Commenter IV-D-39 estimated the cost of thermal measurement equipment to range from $7,000 to $15,000 per boiler depending on the specific requirements of the system. The commenter also provided two pages of cost data.

Response: Owner's or operator's would be allowed to request the approval of alternative monitoring procedures. However, with the change in the format of the standard, the use of the proposed input to output conversion equation would no longer be necessary. The EPA anticipates that most sources will comply with the standard through the continuous monitoring of NO_x outlet emissions.

5.3 GROSS VERSUS NET OUTPUT VARIABLE IN EQUATION

Comment: Commenter IV-D-54 supported the use of the net output format. The reason given was that this format will encourage owners and operators to lower the auxiliary power requirements at the facility. Commenter IV-D-50 added that the emission limit should be based on the net energy leaving the facility.

Commenter IV-D-46 stated that the output-based standards should be defined as lbs NO_x/MWh net for utility boilers or lb NO_x/MMBtu at the steam header for other boilers.

In contrast, Commenters IV-D-37 and IV-D-42 opposed basing the output standard on the net output term. Commenter IV-D-37 specified that the certified monitoring of electric power output would add another layer of monitoring requirements while providing "no real benefit." Further, Commenter IV-D-37 reported that the output-based format would "require significant and costly changes to the software of monitoring and reporting systems." Further, the commenter explained that the issue of measurement location is unresolved by noting the discrepancy in the definition as "the net electrical output (i.e. net busbar power leaving the plant) from the turbine generator set." The term "net" means the sum of the power leaving the generating units minus the power required to drive auxiliary equipment. Commenter IV-D-42 recommended basing the standards on gross rather than net output to account for the power drain associated with many types of control technologies.

Commenters IV-D-36 and IV-D-47 reported that electrical output cannot be measured directly because it is dependent on the "electrical usage by hundreds of motors and other auxiliary equipment located throughout the plants." The commenter claimed that net generation cannot be measured "by simply installing a wattmeter."

Response: The EPA has reconsidered its position, and has decided to finalize the rule based on the use of gross output because of the monitoring difficulties inherent in the net output methodology. In particular, measuring net output at facilities with both affected and nonaffected units could be problematic, because a single meter on the electricity leaving the facility could not sufficiently allocate the electricity leaving the affected boiler. The EPA reserves the opportunity to revisit this issue should EPA develop a methodology to determine the net heat output in all circumstances.

Comment: Commenters IV-D-32, IV-D-37, IV-D-47, IV-D-52, IV-D-54, and IV-D-55 protested that the proposal did not include a specific methodology for determining the unit net output, but that a methodology will be in the final rule. One commenter pointed out that this does not provide for a subsequent comment period on a “significant component” of the proposal. Commenter IV-D-52 urged the EPA to “withdraw this proposal until a complete and thorough package can be provided for full public review and comment, as required.”

Response: The changes made in the final standard make the commenters’ concerns about a specific methodology to determine unit net output immaterial.

6.0 REVISED STANDARD FOR ELECTRIC UTILITY STEAM GENERATING UNITS (SUBPART Da)

6.1 SUPPORT THE LEVEL OF THE STANDARD

Comment: Commenters IV-D-07, IV-D-33, and IV-D-57 supported the level of the standard. Commenter IV-D-57 stated that the proposed 1.35 lb/MWh standard was achievable for electric utility steam generating units with post-combustion NO_x controls, either alone or combined with combustion controls. The commenter pointed out that oil- and gas-fired units in California use SCR and have emissions below 1.0 lb/MWh. The commenter also indicated that there are coal-fired units that emit less than the proposed standard. One example is a new coal-fired boiler in Virginia that achieves SCR reductions of 60-65 percent and has outlet emissions below 0.08 lb/MMBtu (heat input). Commenter IV-D-07 complimented the EPA on the fact that these standards are stricter than all of the previous non-gas standards.

In support of the EPA's analysis, Commenter IV-D-51 referred to a report entitled “Fuel Choice for New Electric Generating Capacity in the Next Century: Coal or Natural Gas”, and provided a copy of this report for EPA review. Commenter IV-D-51 stated that the report confirmed the application of SCR or FBC with SNCR can achieve 80- to 90-percent NO_x removal, yielding a representative emission rate of 0.05 lb/MMBtu to 0.20 lb/MMBtu. The commenter also stated that emission reductions from existing utility plants would be required to achieve the new federal standard for ozone, and that retrofit of existing plants to meet the proposed standard would be feasible and cost-effective.

Commenter 1 supported the proposed NO_x limit of 1.35 lb/MWh. However, the commenter noted that only 17 new utility boilers were planned for the next five years and that "the real NO_x problem will likely come from industrial boilers."

Response: The EPA appreciates the commenters' support.

6.2 STANDARD IS TOO LENIENT

Comment: Commenter IV-D-58 stated that the proposed standard is much too lenient and does not reflect the "best demonstrated technology." Commenter IV-D-58 reported reviewing NO_x data for Phase 1 and Phase 2 coal-fired units and found that the average Btu-weighted emissions rate in 1995 was 0.58 lb/MMBtu. Commenter IV-D-58 then assumed an 80-percent NO_x removal rate for SCR, and calculated a controlled emission rate of 0.12 lb/MMBtu, which is lower than the presumptive limit upon which the proposed standard is based. However, a new boiler, which should be equipped with low-NO_x burners, should have a much lower uncontrolled baseline, resulting in much lower emissions from the SCR. The commenter believes an emission limit of 0.08 lb/MMBtu is achievable, especially because 25 percent of all coal-fired boilers in the EPA's Acid Rain Program inventory have a NO_x emission rate of 0.40 lb/MMBtu, and when reduced by 80 percent, yields 0.08 lb/MMBtu. The commenter added that 1995 CEMS data show that 41 percent of those units in the EPA'S Acid Rain database emitted at 0.05 lb/MMBtu or lower. For oil-fired units, commenter IV-D-58 noted that in the Acid Rain database the average NO_x emission rate was 0.184 lb/MMBtu, with 35 percent of the facilities in the database below the NSPS limit. Commenter IV-D-58 concluded by stating that is "inappropriate for EPA to establish limits that can already be met by a substantial portion of the existing fossil fuel-fired population."

Response: The commenter's assumption of an 80 percent NO_x removal rate is based on a unit that emits more NO_x than would be emitted at baseline by units considered under the NSPS analysis. For example, the Logan SCR has an average NO_x removal rate of 65 percent. Therefore, to approach the NSPS limit with a requirement for this high level of removal does not reflect actual conditions at new units. Also, there are additional costs associated with meeting more stringent limits, especially with respect to the amount of ammonia and catalyst required and the increase in ammonia slip.

6.3 STANDARD IS TOO STRINGENT

Comment: Commenters IV-D-16, IV-D-25, and IV-D-59 stated that the standard is too restrictive. Commenter IV-D-25 speculated that a standard that is too strong might discourage construction of new, clean, and efficient plants, or eliminate the use of lignite. The commenter recommended reviewing the standards if no new plants are built to conform to them within two years of finalization.

Commenter IV-D-59 also noted that the standard imposed a 35-percent emission reduction for natural gas-fired units, and this percent emission reduction should also be applied to coal-fuel emission rates. The commenter recommended an emission limit for coal-fired units of 0.35 lb/MMBtu.

Commenter IV-D-31 reported that the NSPS level for coal-fired boilers is lower than the lowest emitter in the database. The commenter reviewed the EPA Acid Rain database on the Internet for the facilities in the NSPS database. The commenter found that the Merrimack 2, from the NSPS database, is not a new boiler, but an SCR retrofit on an older cyclone boiler. Further, the Stanton 2 plant's emission rate of 0.163 lb NO_X/MMBtu (second quarter 1997) which equated to an emission rate of 1.67 lb NO_X/MW-hr. This emission rate is higher than the EPA's proposed limit of 1.35 lb NO_X/MW-hr. The commenter asked, "How does EPA justify a rate lower than a state of the art plant?"

Response: As discussed, the EPA has revisited the format of the final standard and has revised it accordingly. Regarding the performance of the Stanton plant, the EPA’s analysis shows that it would meet the revised standard of 1.6 lb/MWh, based on a 30-

day rolling average.

STEAM GENERATING UNITS (SUBPART Db)

7.1 EXCLUSIONS

_______: Commenters IV-D-22 and IV-D-26 stated that the EPA should not apply the proposed standard to modified and

waste heat systems are typically installed in the ductwork of a gas turbine exhaust and are not amenable to significant

$_x$ control because of their configuration.

reconfiguration is extremely limited, and possible back pressure impacts on the upstream device are a major concern. Applying the

because the NO from the upstream device (i.e., combustion turbine) cannot be separated from the steam generator NO for purposes of add-on control. The commenters said that add-on controls are not demonstrated for such systems.

________: As described in the response to the comment under section 4.1.1, the EPA is not aware of any instances where

to the NSPS, nor does the EPA anticipate such instances in the future. The General Provisions already provide several

For example, sources that offset their increased emissions are not subject to the NSPS because of modification. These

modification provisions to existing sources.

The systems described by the commenters would be subject to

As discussed earlier, the EPA agrees that ICCR-driven revisions to subpart GG could pose a potential conflict with the subparts

Da and Db standards, if they extend the applicability of subpart GG to the duct burner, which is currently covered by subparts Da and Db. Therefore, the EPA will revise subparts Da and Db to exempt sources that may also become subject to subpart GG, should such revisions to subpart GG occur.

Comment: Commenters IV-D-09, IV-D-11, IV-D-12, IV-D-13, IV-D-15, and IV-D-45 noted that the proposed revision appears to apply to all steam generating units, including units that are excluded from the current standard because they fire 10 percent or less fossil fuel. The commenters did not believe that the EPA intended that the revised NO_x limit should apply to facilities that combust a limited amount of fossil fuel. Several commenters suggested clarifying the following language to at the end of 40 CFR 60.44b(l)(1): "...86 ng/J(0.20 lb/million Btu) heat input *unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a Federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas;* or ....”

Response: The EPA did not intend to remove the 10-percent exemption from the revised NSPS. The EPA will add the suggested regulatory language to clarify that this exemption still holds.

Comment: In addition to recommending the revised language cited above, commenters IV-D-09, IV-D-12, and IV-D-13 pointed out that, as written, the proposed NO_x revisions would include municipal solid waste combustors that only use a limited amount of fossil fuels for startup purposes and supplemental fuel during those periods when the heat content of the waste is low, in order to maintain good combustion conditions. The commenters stated that the proposed Subpart Db NO_x emission limit revisions would be approximately 120 parts per million, by volume, dry (ppmdv) (corrected to 7% O_2), as compared to the revised NSPS for large municipal waste combustors (MWC) units (December 19, 1995, Federal Register 40 CFR 60 Subpart Eb) that limits NO_x to 150 ppmd, corrected to 7% O_2

three years of operation. Commenter IV-D-09 added that existing

(EG) in 40 CFR 60 Subpart Cb to meet a NO emissions limit of 205 ppmdv corrected to 7% O (daily arithmetic average). The commenters suggested that the addition of the 10-percent exemption, discussed above, would alleviate this concern. In

sense to exempt facilities entirely that are subject to the subpart Eb and Cb requirements.

________: As discussed above, the EPA has included the language regarding the 10-percent exemption to the final rule,

will revise the final rule to exempt units that are subject to subpart Eb to avoid any possible conflicts.

Comment: Commenter IV-D-57 stated that the proposed

quite reasonable. According to the commenter, several units burning a wide variety of fuels currently use SCR and other

x emissions below this level.

numerical standard to encourage innovation in pollution prevention. The commenter stated that the 0.20 lb\ MMBtu NO limit would require the application of at least one control technology or a combination of the technologies cited in the

will add complexity to the operation of the affected source. The commenter was unable to determine an appropriate recommendation the EPA in order to develop a reasonable value that allows the necessary flexibility.

Commenter 1 stated that the NO_x emission limit of 0.2 lb/MMBtu was not adequate. The commenter pointed out that the EPA has estimated that 381 new industrial boilers will be built in the next five years (293 natural gas/distillate oil, 66 residual oil, and 22 coal). The commenter indicated that the new standards, as currently proposed, would ignore the 293 new natural gas and distillate oil units that are predicted over the next five years. The commenter requested that the standard be set at 0.15 lb/MMBtu (except for low-heat gas and distillate oil units), and enforced using the best available control technology. Commenter IV-D-05 agreed with this comment, reasoning that a 0.15 lb/MMBtu emission level was achievable for industrial sources stating that the best available technology should be used on all new sources.

Response: The EPA believes that the proposed 0.20 lb/MMBtu is the appropriate level for the subpart Db standard, and will finalize this limit in the promulgated standard. The EPA evaluated the costs associated with controlling natural gas and distillate oil units to the 0.15 lb/MMBtu level, and found that their smaller size and lower capacity factors resulted in much higher cost-effectiveness values associated with the application of flue gas treatment than do coal-fired units. As stated in the proposal Federal Register notice, the 0.20 lb/MMBtu limit would result in approximately a 70-percent reduction in the annual nationwide costs for new industrial steam generating units compared to establishing a limit at 0.15 lb/MMBtu for all new units. However the 0.20 lb/MMBtu limit reflects about a 50- to 70-percent reduction in NO_x emissions over the current subpart Db limits for coal-fired and residual oil-fired units. Based on these cost considerations, the EPA has determined that establishing a lower limit for natural gas and distillate units is not justified.

7.3.1 Support Input-Based Format

_______: Commenters IV-D-10, IV-D-19, IV-D-22, IV-D-24, IV-D-26, IV-D-36, IV-D-37, IV-D-45, IV-D-64, and IV-D-65 supported

to be input-based. Commenter IV-D-22 opposed the output-based standard for industrial boilers, because they operate complex

The commenter wrote that "it would be extremely difficult, if not impossible, to reliably monitor an output-based standard."

would add complication for the following reasons:

(1) Permit limits, Title IV limits, and other regulations

(2) The output-based standard cannot be applied equitably to all sources because the standard used a rate of 9,000

(3) The NSR program would be a disincentive to improving efficiency. Further, if an output-based standard is set, it

net, to account for power drain from pollution control equipment.

monitoring equipment.

(5) The industrial sector contains economic drivers to

(6) Implementation of an output standard would be almost impossible for the industrial sector due to the variety of

and IV-D-26 added that downstream conditions limit the achievable efficiency of the boiler, adding that they may be required to reduce the pressure of the steam generated in order to supply steam at a lower pressure for a particular process. These constraints by the production processes lowers the calculated efficiency of the boiler. Also, steam is generated from waste heat systems where possible. Waste heat availability is highly variable, which means the efficiency of a waste heat system is highly variable.

Response: The EPA appreciates the commenters' support. The EPA continues to believe that the input-based format is appropriate for industrial boilers.

7.3.2 Oppose Input-Based Format

Comment: Commenters IV-D-18, IV-D-39, and IV-D-54 recommended that the EPA consider an output limit for industrial steam generating units. Commenter IV-D-18 recommended that the limit be determined on a case-by-case basis, where it can be applied as an alternative to the input limit. In contrast, commenter IV-D-54 recommended a unilateral limit because it would give preference to higher efficiency systems and because the owner/operator would be more attentive to plant operations to "ensure efficient operation."

Commenter IV-D-39 said that a longer averaging period, i.e., 12 months, would address the load variability issues associated with industrial boilers meeting an output-based standard. The commenter also argued that output-based standards will promote improved boiler efficiency at both initial installation and over the life of the boiler. The commenter said that factors such as basic combustion design, use of air or water preheaters, economizers, fans, and heat exchangers all affect efficiency and will be the basis for efficiency improvement if the regulations provide the incentive. In addition, an output-based standard will encourage the owner or operator to maintain the efficiency of his or her new boiler over the life of the unit or to find ways to offset decreases in efficiency. Finally, the commenter argued that the measurement issue is addressed if the output is measured as the full enthalpy of thermal energy (steam or hot water) leaving the boiler. The enthalpy can be calculated automatically from the temperature and pressure sensors that are part of the steam flow metering system. According to the commenter, the cost of thermal measurement equipment can range from $7,000 to $15,000 per boiler.

Commenter IV-D-50 noted that the current input-based standards have not provided incentives for efficiency and pollution prevention. The continuation of input-based standards would not encourage efficiency in planned units.

Response: The EPA continues to believe in the value in promoting pollution prevention and energy efficiency in the regulatory process. Unfortunately, in this case, the nature of industrial boilers and their use patterns seems to preclude the practical application of an output-based format. As stated at proposal, the EPA did consider an output-based format option of lb NO_x/million Btu steam output, which could be applicable to all new industrial boilers. However, this output-based format option provides the owners with only minimal opportunities for promoting energy efficiency at their respective facilities, because it accounts only for boiler efficiency and ignores both the turbine cycle efficiency and the effects of energy consumption internal to the plant. The boiler efficiency is mainly dependent on fuel characteristics. Beyond the selection of fuels, plant owners have little control over boiler efficiency. In addition, an output-based format would require additional hardware and software monitoring requirements for measuring the stack gas flow rate (for determining the mass rate of NO_x emissions), steam production rate, steam quality, and condensate return conditions.

Instrumentation to conduct these measurements may not generally exist at industrial facilities as they do at utility plants.

Commenter IV-D-18's suggestion to allow the use of an output-based format as an alternative to the input-based format on a case-by-case basis would overcome the difficulties associated with the variability in baseline efficiencies of industrial boilers. In some cases, energy efficiency might be effectively encouraged, but the difficulties associated with monitoring such systems on a routine basis would still be present. Therefore, the EPA has not changed the rule to reflect this option. However, the NSPS would not preclude individual States or sources (through Title V permit streamlining) from pursuing this option when it can be demonstrated that equivalent emission reductions could be obtained as under the NSPS.

Regarding the proposal to measure steam output from the boiler as the means of demonstrating compliance with the output standard, owners or operators could request use of such alternative means on a case-by-case basis under the part 60 General Provisions.

8.0 CONTINUOUS EMISSION MONITORING (CEM) REQUIREMENTS

8.1 GENERAL

_______: Commenter IV-D-08 requests that the EPA make the reference to Part 75 CEMS much broader, so that it is readily

ranges, quality assurance, etc.) satisfy Subpart Da and Db provisions.

________: In the past, the EPA determined that Acid Rain CEMS can be used as NSPS Subpart Da CEMS. That determination is

Assurances’s web site. However, all of these CEMS must generate reports according to the requirements of the applicable subpart

(State) in the regulatory format and by means acceptable to that authority. The EPA is adding language to both subparts Da and Db

the part 60 requirements.

8.2 APPLICABILITY TO SMALL/SEASONAL UNITS

_______: Commenter IV-D-14 requested that the CEM requirements for new low-NO_x
reviewed, especially for boilers only used on a seasonal basis.

nitrogen oxide emission limits on old and new boilers that "far exceed the limits contemplated in the proposal." Commenter IV-D-

processors in California provide no added assurance of compliance, but merely add significant costs which are not

<u>Response</u>: As discussed in section 7.1, the EPA is

should also address the concerns of small, seasonal boilers.

Comment: Commenter IV-D-01 recommended that the EPA eliminate the CEMS requirements and associated reporting and recordkeeping requirements in Subpart Db for steam generating units that have a heat input capacity of 250 MMBtu/hy or less, fire natural gas, and whose NO_x emissions are 30 ppm (0.037 lb/MMBtu) or less; and, instead require only initial and annual emission testing. The commenter noted that their proposed emission limit for CEMS requirement is about one third of the 0.1 lb/MMBtu limit and one fifth of the 0.2 lb/MMBtu limit in the proposal. The commenter explained that this emission rate is the limit in California. Commenter IV-D-01 stated that the testing, monitoring, reporting, and recordkeeping requirements for steam generating units regulated by Subpart Db are extensive as well as costly. The commenter also noted that this would give the facility the choice between installing a low NO_x emitter (NO_x emissions of 30 ppm (0.037 lb/MMBtu) or less) or a higher NO_x emitter with a CEMS. Further, the commenter provided recommended language to revise the proposed NSPS.

Response: As discussed at proposal, the EPA believes the monitoring costs associated with Subpart Db are reasonable and necessary. In any case, low emitters have an option to petition the EPA for alternative monitoring methods according to section 60.13(i) of the part 60 General Provisions.

8.3 CONSISTENCY BETWEEN PROGRAMS

Comment: Commenter 2 stated that "several Subpart Db NO_x monitoring procedures could benefit from revision or elaboration to clarify ambiguities in the existing rule and eliminate inconsistencies with overlapping specification imposed by other programs, such as Acid Rain, NO_x Budget, and NO_x RACT." The issues commenter 2 identified as warranting review include data validation procedures, continuous emissions monitoring system (CEMS) configuration specifications, and methods of compliance determination. Additionally, commenter IV-D-54 recommended that the EPA adopt the Title IV requirements whenever there are common requirements between the NSPS and Title IV.

Data Validation. For data validation of the monitoring process, commenter 2 indicated that the requirements for Subpart Db differ compared to the criteria under the Acid Rain and NO_x Budget monitoring programs. Commenter 2 stated that two parallel data processing systems and databases would have to be maintained to meet the different requirements.

Definition of Operating Status. Commenter 2 reported that the definition of the operating status of partial operating hours also differs between Subpart Db and the Acid Rain and NO_x Budget Programs. Specifically, commenter 2 reported that for Subpart Db, any hour in which a combustion unit is on-line for less than 30 minutes should be ignored for purposes of monitoring compliance. However, both the Acid Rain and NO_x Budget Programs require that all operating time be accounted for, so that no CEMS data can be ignored during on-line periods. As in the data validation case stated above, the commenter indicated that these differences lead to apparent reporting conflicts.

Span Value of the CEMS. Commenter 2 noted differences in the span value of the CEMS. Commenter 2 explained that the span value of the CEMS is the primary determinant of the allowable daily calibration drift. Commenter 2 continued by stating that Subpart Db establishes 500 ppm as the span for NO_x if oil or gas are being combusted, and 1000 ppm if coal is being fired. The commenter reported that this value is "markedly lower than 500 ppm" for new boilers under the Acid Rain procedures. Commenter 2 concluded that it is possible for the measured daily calibration error to be small enough to be acceptable under NSPS, but large enough to trigger an out-of-control condition under Acid Rain, NO_x Budget or NO_x RACT.

Compliance Determination: Commenter 2 addressed the difference in compliance determination depending on the fuel used. Commenter 2 reported that under Subpart Db compliance is evaluated on a 30-day rolling average basis; however, there are different compliance determination periods for low-heat release units that fire gas and distillate, and those that fire other fuels. He pointed out this discrepancy, presumably to allow the EPA to better coordinate the compliance determination between the different fuel types.

Treatment of Emission Limits During Hours of Invalid Data Collection. Commenter 2 reported that there is no explicit guidance on the treatment of emission limits during hours of invalid data collection. Commenter 2 recommended that if no valid measurement data are available for an hour, then the accompanying emission limit should also be omitted in the calculation of the 30-day average. Done this way, commenter 2 indicated that the emission rate and emission limit would be calculated using the same hourly data set (i.e., considering valid CEMS hours only).

Response: A subpart Db boiler equipped with an acid rain CEMS can use this CEMS as a subpart Db CEMS. The reports generated by this CEMS must be generated according to the provisions of subpart Db and submitted to the authority in charge of the NSPS program, because the NSPS and acid rain programs have different requirements and are managed by different authorities. Regarding data validation procedures, the EPA headquarters already maintains the acid rain data base and the AIRS data base, which is suitable for reports from non-acid rain programs. In addition, several States maintain their own data bases. The EPA believes that the data validation issue should not lead to any conflicts considering that the acid rain and the subpart Db report formats must follow their own requirements.

The EPA headquarters has addressed a few span-related issues upon request and will continue this practice under the part 60

Finally, emission limits during hours of invalid data must be met using other means than CEMS data according to the

applicable. As discussed above, the EPA has added language to sections 60.47a(c) and 60.48b(b) to clarify the relationship

to demonstrate compliance with the part 60 standards.

8.4 AVERAGING PERIODS

Support 30-Day Averaging Period

Comment

stated that the 30-day rolling average period should be sufficient to account for operating efficiency variability.

compliance requirements consistent under Subparts D and Da, adding that Subpart D units should be allowed to demonstrate

IV-D-08 added that "it doesn't make sense that the averaging period is shorter for an older standard."

________: The EPA appreciates the commenters' support. However, expanding the averaging period in subpart D is beyond

time.

8.4.2 ______________________________

Comment: Commenter IV-D-50 stated "EPA should recognize the

$_x$ emissions on a daily basis, evaluate the

$_x$ emissions from power plants on

emission limit on a 24-hr basis."

Commenters IV-D-19, IV-D-20, IV-D-24, IV-D-34, IV-D-39, IV-

D-42, IV-D-44, IV-D-46, IV-D-52, and IV-D-65 expressed concern that a 30-day rolling average may be insufficient to account for variability in operating efficiency. Commenters IV-D-19, IV-D-24, IV-D-34, IV-D-39, IV-D-42, IV-D-44, IV-D-46 and IV-D-65 recommended a 12-month averaging period, while commenter IV-D-52 recommended a 6-month period. The commenters explained that this period is consistent with the NO_x standards under the Acid Rain Program. Commenters IV-D-19 and IV-D-65 explained that the 12-month period will be "environmentally neutral" explaining that the mass of emissions is equivalent regardless of the averaging period. Another reason stated by commenters IV-D-19, IV-D-20, and IV-D-65 was that a longer averaging period will allow further opportunities for pollution prevention. Another reason given by Commenter IV-D-39 was that the effect of partial load operation on the efficiency can be accommodated with a 1-year averaging period.

Response: The EPA has not proposed any change to the averaging period in the NSPS, and will not do so now. As demonstrated by the four facilities analyzed after proposal who all meet the revised output standards, 30-days is sufficient to account for operational variability.

8.5 SUPPORT ELECTRONIC FILING

Comment: Commenter IV-D-47 supported the EPA's attempt to streamline reporting by allowing quarterly electronic reports and consolidation of NSPS Subpart Da and Part 75 reporting requirements. However, the commenter "does not believe that the proposed language provides a meaningful standard for determining when reports are acceptable or for resolving any of the issues that are likely to arise in implementing consolidated reporting." The commenter stated that if the EPA intends to limit the new option to reporting under a specific format, the EPA should propose language indicating that, and "commit to working with utilities to ensure that the format is consistent with existing formats, like Part 75." Additionally, the commenter emphasized

optional."

Commenters IV-D-24, IV-D-37, IV-D-42, IV-D-44, IV-D-52, and

reporting for Subpart Da and Db units. The commenters stated that this action will reduce the burden on affected units and

the Acid Rain Program requirements under 40 CFR 75. The following recommendations were made:

reporting under Subpart Da (inlet SO and CO_2 concentrations, SO_2 electronic format along with outlet emission parameters.

data algorithm required by Part 75 should treat periods of missing or invalid data for the purposes of electronic

(3) Existing Subpart D units be allowed to file electronically, as they should not be required to file

switch to electronic reporting.

Commenter IV-D-54 recommended that the EPA adopt the Title

the NSPS and Title IV.

Commenter IV-D-59 noted that the voluntary provision for

additional reporting requirements than might already be required for a specific source. The commenter noted that the opacity

submitting other required data in electronic format.

Response: In general, the EPA supports electronic submittal of the reports, provided that those reports are generated in the format required under all applicable regulations and submitted to the appropriate authorities. A facility choosing to submit reports electronically must obtain an agreement from the EPA Regional offices and the State authority.

The missing data procedures required by part 75 are not acceptable under subpart Da.

As discussed above, the EPA has added language to section 60.47a(c) to clarify that "If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49a. Data reported to meet the requirements of §60.49a shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter." Similar language has also been added to section 60.48b(b) to clarify the use of part 75 CEMS with subpart Db affected facilities.

8.6 NEW MONITORING AND PERFORMANCE TESTING REQUIREMENTS

At a February 18, 1998 meeting with representatives from the Utility Air Regulatory Group and the National Mining Association, representatives identified the following issue related to the potential variability in data from monitoring systems. A complete summary of this meeting is in the project docket.

Comment: Mr. Kanary noted that when the EPA Acid Rain Division studied the problem of heat input they back-calculated the heat input from the flow monitors and the carbon monoxide monitors. They found that there was a difference of as much as

20 percent between the CEM data and the fuel analysis. Mr. Wilson reported that the differences vary from site-to-site because the error depends on the location of the monitor and the design of the ductwork. This difference is the result of flow meter errors. Flow meters are designed for laminar flow, and actual duct conditions are not laminar flow.

Mr. Wilson explained that to have an accurate flow meter reading, the ductwork would need to be extremely long and straight and use larger fans. This type of ductwork would be extremely costly to implement, assuming that space was not an issue, which it often is. As an alternative flow measurement approach, Mr. Wilson recommended using venturi nozzle to measure the pressure drop. Mr. Harrison concluded the discussion of this topic by stating that there was no proposal on the table on how to resolve the issue and added that he is requesting 3 weeks to comment on whatever method the Agency proposes.

Response: Under Part 75, flow monitors are used with SO_2 CEMs to determine SO_2 mass emissions and to verify that utility units meet their allowance obligations each year. Recently, utilities have expressed concern that Test Method 2, EPA's reference method for certifying flow monitors, may cause flow monitors to read high under certain flow conditions. This could cause SO_2 emissions to be over reported. Because flow monitors and CO_2 CEMs are used by utilities to calculate heat rate, there is also concern that some heat rates may be overestimated.

Because of these concerns, the Acid Rain Program conducted three field studies this past summer at two gas-fired and one coal-fired power plant to test the performance of seven probes and several new procedures being considered for revisions to Test Method 2. In addition, several wind tunnel studies have or will be performed, including pre- and post-test probe calibrations at North Carolina State University, post-test probe calibrations at the National Institute of Standards and Technology, possible Reynolds Number (temperature) effects on probe calibration at a variable density wind tunnel at the Massachusetts Institute of Technology, and testing in an Electric Power Research Institute ‘swirl’ wind tunnel to determine probe performance under controlled yaw and pitch conditions.

Work is under way on a draft findings report along with draft Test Method revisions. These documents will be peer reviewed in the next several months and will be the basis for Test Method 2 revisions, which are expected to be published by the end of 1998.

In the meantime, if a utility has swirling flow, and suspects their flow monitor measurements, flow straighteners may be installed, without pressure drop penalty in many instances. Several utilities have installed flow straighteners and have found reductions in their volumetric flow measurements and heat rate disparity. Other utilities have reported improvements through the use of automated implementations of Method 2 and through taking measurements at more traverse points than the minimum required under Method 1. Heat rate disparities can also be reduced through tighter quality assurance of (1) fuel sampling and analysis procedures to ensure that their calculations are not biased low, and (2) of CO_2 CEMs to ensure that their measurements are not biased high.

Finally, the EPA believes that new units, which are the primary types of sources to be affected by the NSPS, can be designed to overcome measurement problems.

9.0 OTHER

9.1 COST, ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS

Comment: Commenters IV-D-31, IV-D-38, IV-D-42, IV-D-47, and IV-D-52 stated that the EPA did not adequately perform the nonair quality, health and environmental impact and energy requirements analysis. Commenter IV-D-63 quoted Section 111 of the Clean Air Act to say that rulemaking must balance the environmental and cost factors. The commenter stated that this rulemaking "does not produce any tangible health and welfare benefits," and would cause an increase in energy costs.

Commenter IV-D-50 suggested that the EPA expand on the environmental impacts discussed in Section VI of the proposal. The commenter encouraged the EPA to note the role of NO_x in local and regional ozone formation.

Response: As demonstrated by the regulatory impact analysis, the EPA believes that the impact analysis, with the modifications conducted as the result of the evaluation of public comments, is sufficient to support our regulatory decisions.

Comment: Commenter IV-D-40 urged the EPA not to adopt the proposed NSPS because the rules could have a negative effect on the cost of producing electricity, particularly in the case of coal-fired electric utilities. The commenter asserted that an increase in the cost of electricity would reduce the use of electrotechnologies throughout the economy. The commenter stated, "By reducing economic growth, the proposed rules would hinder the ability of Americans to purchase a safer environment and improved health care. And by raising the relative price of electricity, the proposed rules would impede market penetration of a wide array of technologies that could produce major benefits for American health and safety."

Response: The EPA believes that the impacts of the standards have been adequately addressed, that the final rule is justified based on these impacts, and that no revisions to the impacts analysis are needed.

9.2 EDITORIAL

Comment: Commenter IV-D-27 pointed out that the equation in section III.D. of the proposal preamble used to calculate the output based standard is incorrect. The commenter stated that the equation should be $E_o = (E_i)(n)/1000$.

Response: The commenter correctly noted the error in the equation. The EPA has used the correct equation in the actual analyses.

Comment: Commenter IV-D-50 requested clarification of the units for emission limits. The proposed units are pounds NO_X per MWh or MMBtu. The commenter noted that most NO_X is emitted as NO and a small fraction is NO_2. The commenter stated that it would be "useful to clearly state that the NSPS limits are in pounds of NO_X as NO_2, as is traditionally done."

Response: As noted by the commenter, the current section 60.44a does not distinguish NO_X as NO_2, nor did the proposed amendments. However, section 60.44b, both in its current version and as proposed does. In order to correct this discrepancy, the EPA will revise the final section 60.44a to express NO_X as NO_2.

Comment: Commenter IV-D-47 requested "that the regulatory language in § 60.44a(d) explicitly state that the basis for compliance is a 30-day rolling average." The commenter noted that "The proposed rule is somewhat ambiguous, and the mention of the 30-day rolling average in § 60.44a(a) on its face only applies to the standards in § 60.44a(a)."

Response: The EPA agrees that the addition of the language specifying that the emission limits are to be based on a 30-day rolling average to section 60.44a(d) is a useful clarification. This change will be made in the final rule.

9.3 GLOBAL WARMING

Comment: Commenter IV-D-04 warned that "all air temperature readings on which decisions on matters pertaining to global warming are made are suspect." The commenter recommended that the readings include humidity as a factor and decisions regarding global warming and NO_x control regulations be revised accordingly. Further, the commenter warned against establishing policy and regulations based on "suspect" data.

Response: The EPA appreciates the commenter's input. The EPA does its best to ensure that its regulations are based on sound science.

9.4 BEST AVAILABLE CONTROL TECHNOLOGY

Comment: Commenter IV-D-37 recommended that the EPA issue guidance stating that gas-fired boilers and gas-fired combustion turbines with duct-firing, which are able to meet the new NO_x standard, constitute best available control technology (BACT) for the purposes of Prevention of Significant Deterioration (PSD) permitting.

Response: This request is beyond the scope of the rulemaking.

9.5 APPLICABILITY OF THE CREDIBLE EVIDENCE RULE

Comment: Commenter IV-D-47 noted that the EPA recently amended Part 60 to include the credible evidence (CE) rule. The commenter expressed opposition to the CE rule. Because the proposed NSPS clearly indicates how compliance is determined, the commenter believes "that the CE rule has no application to this NSPS," and requested that the EPA clearly state so.

The commenter stated that if the EPA intends for the CE rule to apply to this NSPS, the EPA must supplement the proposal and allow additional comment regarding application of the CE rule. The commenter requested clarification as to what kind of information could be "considered to be evidence of a violation of this NSPS." The commenter also requested a discussion of the effect of data other than compliance method data on the ability of source owners or operators to determine compliance, and to certify compliance under Title V, for this NSPS.

Response: The CE rule is applicable to all NSPS regulations, as well as to other programs, as determined in the rule. The public comment period for the CE rule was closed a few years ago. The NO_x limit compliance determination method under this NSPS NO_x rule is a NO_x CEMS. In addition, other credible evidence such as evidence of tampering with the CEMS or destruction of valid data, could also be used to allege non-compliance.

9.6 ADDITION OF TECHNICAL DOCUMENTS TO THE RECORD

Comment: Commenter IV-D-47 attached "a large number of pertinent technical reports and studies that are not in the rulemaking record" along with the comments. The commenter urged EPA to "review and evaluate all pertinent technical literature, not simply those papers that might support a preconceived position."

Response: The EPA has considered all of the material provided by commenters in developing the final rules.

9.7 FEDERAL INTERVENTION

Comment: Commenter IV-D-66 supported federal intervention in regulations that improve the health and environment of the American citizens.

Response: The EPA appreciates the commenter’s support.

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(Please read Instructions on reverse before completing)

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15. SUPPLEMENTARY NOTES

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16. ABSTRACT

This document presents a summary of public comments regarding development of revised air emission standards for NOx emissions from electric utility boilers and industrial boilers and EPA's responses to those comments.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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