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Volume 3

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
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EPA-450/3-86-003

FOSSIL AND NONFOSSIL FUEL-FIRED INDUSTRIAL BOILERS - BACKGROUND INFORMATION FOR PROMULGATED PM AND NO_x STANDARDS VOLUME 3

Emission Standards and Engineering Division

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

April 1986

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1.0 SUMMARY

On June 19, 1984, the Environmental Protection Agency (EPA) proposed standards of performance limiting emissions of particulate matter and nitrogen oxides (NO_x) from industrial-commercial-institutional steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour) (49 FR 25102; Subpart Db) under authority of Section 111 of the Clean Air Act. Public comments were requested on the proposal in the Federal Register. There were 62 commenters, composed mainly of industries, trade associations, and State and local regulatory agencies. Also commenting were environmental groups and one U.S. Government agency. The comments that were submitted to the docket (A-79-02) are summarized in this document. Revisions were made to the proposed regulations in response to these comments. A description of these revisions and the rationale for the final actions taken by the Administrator are presented in the preamble to the promulgated regulations.

On December 2, 1985, EPA proposed an amendment to the standards of performance for fossil fuel-fired steam generating units (Subpart D) that would revise the NO_x emission limit for units firing mixtures of natural gas and wood (50 FR 49422). Public comments were requested in the Federal Register. There were three commenters, composed of trade associations and one industry. The comments that were submitted are also included in Docket A-79-02 and are summarized in this document.

1.1 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.1.1 Alternatives to Promulgated Action

Regulatory alternatives considered during the development of the proposed standards are discussed in Chapter 6 of "Fossil Fuel-Fired Industrial Boilers - Background Information Document for Proposed Standards" (EPA-450/3-82-006), referred to as the background information document (BID). These regulatory alternatives reflected different levels of emission control. After proposal, the Agency reviewed the public comments and consequently revised the emission limits for particulate matter and NO_x. The Agency has recalculated the environmental, energy, and economic impacts of the final standards, as discussed below.

1.1.2 Environmental Impacts of the Promulgated Action

The environmental impacts of the proposed regulation were presented in the preamble to the proposed standards (49 FR 25102, June 19, 1984) and in Chapter 10 of the BID. Additional background on the environmental impacts of the proposed standards can be found in the docket in two documents entitled "Regulatory Analysis of Recommended Particulate Matter New Source Performance Standard for Industrial Fossil Fuel-Fired Boilers" and "Documentation of National Impacts for Industrial-Commercial-Institutional Steam Generating Units." The environmental impacts of the final regulation are presented in two additional documents, which are contained in the docket. These two documents are "Projected Environmental, Cost and Energy Impacts of Alternative NSPS for Industrial Fossil Fuel-Fired Boilers" and "National NO_x Impacts." The analysis of environmental impacts presented in these documents, as modified by the changes described below, is the final environmental impact statement for this action.

It is projected that 725 new industrial-commercial-institutional steam generating units subject to 40 CFR Part 60 Subpart Db will be constructed in the 5 years following the promulgation. The environmental impacts of reducing particulate matter and NO_x emissions from these steam generating units are expressed as incremental differences in emissions between the current emission regulations (referenced to as baseline) and the promulgated regulations.

The impacts of the new source performance standards (NSPS) for particulate matter and NO_x emissions are stated as a range of emission reductions. This range stems from the different regulatory requirements which can be assumed to apply to new units subject to these standards. The lower estimate of emission reductions is based on the incremental change between the baseline regulations (State implementation plans and Subpart D new source performance standards) and the particulate matter and NO_x emission limits in the promulgated standards. The upper estimate is based on the incremental change between the baseline regulations and the particulate matter and NO_x standards combined with the recently proposed new source performance standards for SO_2 (51 FR 22384), which would also apply to this category of steam generating units. The proposed SO_2 standards are expected to increase the number of natural gas-fired steam generating units subject to the standard from approximately 30 percent of the total number of steam generating units subject to the standards to approximately 55 percent. Because natural gas combustion results in lower particulate matter and NO_x

emissions than either coal or oil combustion, increased particulate matter and NO_x emissions control result with SO_2 standards in place.

Baseline emissions of particulate matter from new industrial-commercial-institutional steam generating units are projected to be approximately 49,000 Mg (54,000 tons) per year in 1990. Under the promulgated standard, particulate matter emissions rates are projected to decrease from those baseline levels by about 16,000 to 22,000 Mg (18,000 to 24,000 tons) per year. Baseline emissions of NO_x from new industrial-commercial-institutional steam generating units are projected to be approximately 77,000 Mg (85,000 tons) of NO_x per year in 1990. Under the promulgated standard, NO_x emission rates are expected to decrease from those baseline levels by about 21,000 to 24,000 Mg (23,000 to 26,000 tons) per year. These emission reductions represent about a 35 to 45 percent reduction in the growth of particulate matter emissions and about a 25 to 30 percent reduction in NO_x emissions from new steam generating units subject to the standards.

The solid and liquid waste impacts associated with the promulgated standards are minimal. The NO_x standards are based on the use of combustion modification techniques to control NO_x emissions, and these techniques do not result in the production of either solid or liquid wastes. Flyash disposal levels associated with existing State regulations and Subpart D new source performance standards are only incrementally increased as a result of the particulate matter standards adopted today. Further, the change in fuel use patterns resulting from the particulate matter and NO_x standards, or from the combined particulate matter, NO_x, and SO_2 standards, can actually reduce flyash levels. Overall, the standards are projected to result in solid waste impacts ranging from a net reduction of about 9,000 Mg/year (10,000 tons/year) to a net increase of 13,000 Mg/year (14,000 tons/year). The liquid waste impacts of the promulgated standards are minimal and are primarily the result of the projected use of wet scrubbing systems for the control of particulate matter emissions from wood-fired steam generating units. Under these regulations, liquid waste production levels would increase from baseline by approximately 19,000 m^3 (680,000 ft^3), or approximately 1.5 percent.

1.1.3 Energy and Economic Impacts of the Promulgated Action

The energy impacts of the proposed regulations were presented in the preamble to the proposed standards (49 FR 25102, June 19, 1984) and in Chapter 10 of the BID. Additional background on the energy impacts of the promulgated standards can be found in the four documents on the environmental impacts of the standards identified above.

Steam generating units that are projected to be affected by the standards are expected to demand approximately 525 million GJ (498 trillion Btu) of fossil fuels in 1990. It is projected that natural gas will provide approximately 30 to 50 percent of the heat input to these steam generating units, and that residual oil will provide most of the remaining steam generating unit fuel. Coal use is projected to be limited to large units with relatively high annual capacity factors.

The use of electrostatic precipitators (ESP's) and fabric filters to comply with the particulate matter standards is expected to increase the national electric energy requirements for new steam generating units by about 146 GWh/year in 1990. This increased electrical energy requirement could be met by combusting an additional 524,000 GJ (497 billion Btu/year) of fossil fuel in an electric utility steam generating plant, or less than a 1 percent increase in the overall annual fuel consumption by new industrial-commercial-institutional steam generating units. The use of low excess air (LEA) for NO_x control will result in fuel savings which will partially offset this increased fuel use.

The economic impacts of the proposed standards were presented in the preamble to the proposed standard (49 FR 25102, June 19, 1984) and in Chapter 9 of the BID. The economic impacts of the proposed standards, in terms of increases in product prices or the availability of capital to the firms purchasing steam generating units, are not expected to change significantly from the impacts identified for the proposed standards. Additional information on the economic impacts of the promulgated standards can be found in the docket in the four documents described above in the section on environmental impacts.

The projected capital and annual costs associated with the promulgated standards vary depending on the regulatory requirements which are assumed to apply to new steam generating units. The addition of the proposed SO_2 standards to the promulgated particulate matter and NO_x standards will result in a slight increase in the cost of NO_x controls. Since reductions in particulate matter emissions are achieved as an incidental effect of SO_2 control under the proposed SO_2 regulation, the total costs of that proposed standard are attributable to SO_2 control alone and are discussed in the preamble to those proposed regulations (51 FR 22384).

The promulgated standards are projected to increase the capital costs of new steam generating units by less than 1 percent over the baseline capital costs. Nationwide annual costs for new industrial-commercial-institutional steam generating units will be approximately $36 million in 1990, or an increase of less than 1 percent over baseline annualized costs. The national average cost effectiveness of the particulate matter standard is projected to range from approximately $1,025 to $1,400/Mg ($930 to $1,270/ton) of particulate matter removed. The national average cost effectiveness of the NO_x standards is projected to range from $370 to $640/Mg ($340 to $580/ton) of NO_x removed.

1.1.4 Other Considerations

1.1.4.1 Irreversible and Irretrievable Commitment of Resources. The long-term gains and losses in environmental resources expected to result from the proposed regulation are discussed in Chapter 7 of the BID. These gains and losses are not expected to change under the promulgated standards. Other than the fuels required for power generation and the materials required for the construction of the control systems, there is no apparent irreversible or irretrievable commitment of resources associated with this regulation.

1.1.4.2 Environmental and Energy Impacts of Delayed Standards. The environmental and energy impacts of delay in the promulgation of the proposed standards are discussed in Chapter 7 of the BID. The results of delay in the standards are that new industrial-commercial-institutional steam generating units would be built which may not meet the emission limitations established by these standards. This would delay the ambient air quality benefits, and other environmental benefits associated with this NSPS. Further, potential improvements in energy efficiency resulting from the adoption of LEA for NO_x control would also be postponed.

1.1.4.3 Urban and Community Impacts. Neither plant closures nor impacts on small businesses are forecast. No significant adverse impacts on urban areas or local communities are anticipated as the result of the promulgation of these standards.

2.0 SUMMARY OF PUBLIC COMMENTS

A total of 58 letters commenting on the proposed standards for control of emissions of particulate matter and NO_x from new industrial-commercial-institutional steam generating units were received. Comments were provided by industry representatives, governmental entities, and environmental groups. These comments have been recorded and placed in the docket for this rulemaking (Docket Number A-79-02, Category IV). Table 2-1 presents a listing of all persons submitting written comments, their affiliation and address, and the recorded Docket Item Number assigned to each comment.

Also, a total of three letters were received commenting on the correction to the proposed rule. This correction proposed to revise the NO_x emission limit for wood residue and natural gas-fired steam generating units. Table 2-2 presents a listing of all persons submitting written comments, their affiliation and address, and the recorded Docket Item Number assigned to each comment.

The comments summarized in this chapter have been organized into the following categories:

2.1 Applicability of the Standard

2.2 Selection/Performance of Demonstrated NO_x Control Technology

2.3 Stringency of the Proposed NO_x Emission Limits

2.4 Selection/Performance of Demonstrated Particulate Matter Control Technology

2.5 Stringency of the Proposed Particulate Matter Emission Limits

TABLE 2-1. LIST OF COMMENTERS ON THE PROPOSED STANDARDS FOR PARTICULATE MATTER AND NITROGEN OXIDES EMISSIONS FROM INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Commenter	Docket Reference
Jan B. Vlcek James P. Rathvon Sutherland, Asbill & Brennan 1666 K Street, N.W. Washington, D. C. 20006	IV-D-1
C. H. Fancy, P.E., Deputy Chief Bureau of Air Quality Management State of Florida Department of Environmental Regulation Twin Towers Office Building 2600 Blair Stone Road Tallahassee, Florida 32301	D-2
James K. Hambright, Director Bureau of Air Quality Control Commonwealth of Pennsylvania Department of Environmental Resources P. O. Box 2063 Harrisburg, Pennsylvania 17120	D-3
Kennard F. Kosky, P.E., Vice President Environmental Science and Engineering, Inc. P. O. Box ESE Gainesville, Florida 32602	D-4
Harold E. Hodges, P.E. Technical Secretary Tennessee Air Pollution Control Board Tennessee Department of Health and Environment T.E.R.R.A. Building 150 Ninth Avenue, North Nashville, Tennessee 37203	D-5
Bruce Blanchard, Director Environmental Project Review United States Department of the Interior Office of the Secretary Washington, D. C. 20240	D-6

Commenter	Docket Reference
W. T. Danker, Manager Environmental Programs Chevron U.S.A., Inc. P. O. Box 7643 San Francisco, California 94120	D-7
Charles P. Blahous, J.D., Vice President Environmental Health and Safety PPG Industries, Inc. One PPG Place Pittsburgh, Pennsylvania 15272	D-8
Walter Roy Quanstrom, General Manager Standard Oil Company (Indiana) 200 East Randolph Drive Chicago, Illinois 60601	D-9
E. William Brownell Hunton & Williams P. O. Box 9230 Washington, D.C. 20036	D-10
John L. Festa, Ph.D. Director, Chemical Control Programs National Forest Products Association/ American Paper Institute 1619 Massachusetts Avenue, N.W. Washington, D.C. 20036	D-11
Harry H. Hovey, Jr., P.E., Director Division of Air New York State Department of Environmental Conservation 50 Wolf Road Albany, New York 12233	D-12
John E. Pinkerton Air Quality Program Manager National Council of the Paper Industry for Air and Stream Improvement, Inc. 260 Madison Avenue New York, New York 10016	D-13
James P. Rathvon Sutherland, Asbill & Brennan 1666 K Street, N.W. Washington, D. C. 20006	D-14

Commenter	Docket Reference
Hugh B. Barton Regulatory Affairs Manager Production Department Exxon Company, U.S.A. P. O. Box 2180 Houston, Texas 77001	D-15
A. G. Smith, Manager Environmental Affairs Shell Oil Company One Shell Plaza P. O. Box 4320 Houston, Texas 77210	D-16
Fin Johnson, Chief Air Quality Section North Carolina Department of Natural Resources & Community Development P. O. Box 27687 Raleigh, N. C. 27611	D-17
K. M. Karch, Manager Regulatory and Environmental Affairs Weyerhaeuser Company Tacoma, Washington 98477	D-18
Charles O. Velzy, P.E., President Charles O. Velzy Associates, Inc. Consulting Engineers 355 Main Street Armonk, N. Y. 10504	D-19
Dalton Yancy Executive Vice President Florida Sugar Cane League, Inc. P. O. Box 1148 Clewiston, Florida 33440	D-20
James E. Walther Supervisor, Air and Noise Programs Crown Zellerbach Environmental Services 904 N.W. Drake St. Camas, Washington 98607	D-21

Commenter	Docket Reference
Daniel T. Skizim Manager of Contract Development American Ref-Fuel P. O. Box 3151 Houston, Texas 77253	D-22
Peter W. McCallum Senior Corporate Environmental Specialist Sohio-The Standard Oil Company Midland Building Cleveland, Ohio 44115	D-23
M. E. Miller, Jr., Manager Environmental Engineering Unit R. J. Reynolds Tobacco Company Winston Salem, N. C. 27102	D-24
Catherine A. Marshall Vice President & Administrator, Technical Department United States Brewers Association, Inc. 1750 K Street, N.W. Washington, D. C. 20006	D-25
J. J. Moon, Manager Environmental and Consumer Protection Phillips Petroleum Company 7 D4 Phillips Building Bartlesville, Oklahoma 74004	D-26
Donald A. Dowling Senior Vice President Chief Operating Officer Cogentrix of North Carolina, Inc. Two Parkway Plaza, Suite 290 Charlotte, N. C. 28210	D-27
W. C. Wolfe, Manager Steam General Business Unit Babcock & Wilcox Industrial Power Generation Division 4282 Strausser Street, N.W. P. O. Box 2423 North Canton, Ohio 44720	D-28

Commenter	Docket Reference
Mark D. Tucker Legal Department The Dow Chemical Company 2030 Willard H. Dow Center Midland, Michigan 48640	D-29
W. H. Axtman Executive Director American Boiler Manufacturers Association Suite 160 950 North Glebe Road Arlington, Virginia 22203	D-30
William T. Burkhard, Supervisor Regional Air Pollution Control Agency 451 W. Third Street P. O. Box 972 Dayton, Ohio 45422	D-31
J. D. Patterson, Manager Environmental Affairs Middle South Services, Inc. Box 61000 New Orleans, Louisiana 70161	D-32
J. A. Barsin, Manager Boiler Components & Equipment Babcock & Wilcox P. O. Box 351 Barberton, Ohio 44203	D-33
U. V. Henderson, Associate Director Environmental Affairs Research Environmental Safety Department Texaco, Inc. P. O. Box 509 Beacon, N. Y. 12508	D-34
F. William Brownell J. D. Fay Hunton & Williams P. O. Box 12930 Washington, D. C. 20036	D-35

Commenter	Docket Reference
Geraldine V. Cox, Ph.D. Vice President, Technical Director Chemical Manufacturers Association 2501 M Street, N.W. Washington, D. C. 20037	D-36
Jan B. Vlcek James P. Rathvon Sutherland, Asbill & Brennan 1666 K Street, N.W. Suite 800 Washington, D. C. 20006	D-37
David G. Hawkins Natural Resources Defense Council, Inc. 1350 New York Avenue, N.W. Suite 300 Washington, D. C. 20005	D-38
J. C. Edwards Clean Environment Program Eastman Kodak Company - Chemicals Division P. O. Box 511 Kingsport, Tennessee 37862	D-39
John L. Festa, Ph.D. Director, Chemical Control Program National Forest Products Association/ American Paper Institute 1619 Massachusetts Avenue, N.W. Washington, D. C. 20036	D-40
Jan B. Vlcek James P. Rathvon Sutherland, Asbill & Brennan 1666 K Street, N.W. Suite 800 Washington, D. C. 20006	D-41
J. C. de Rugter, Senior Engineer, Power Group T. A. Kittmeman, Air Quality and Hazards Engineering Group E.I. du Pont de Nemours & Company, Inc. Engineering Department, Louviers Building Wilmington, Delaware 19898	D-42

Commenter	Docket Reference
Dr. William J. Vullo Environmental Project Engineer General Electric Company Environmental Protection Operation One River Road Schenectady, New York 12345	D-43
Rae E. Cronmiller Environmental Counsel National Rural Electric Cooperative Association 1800 Massachusetts Ave., N.W. Washington, D. C. 20036	D-44
James D. Beatty The Procter & Gamble Company P. O. Box 599 Cincinnati, Ohio 45201	D-45
Jan W. Mares Assistant Secretary for Policy, Safety, and Environment Department of Energy Washington, D. C. 20585	D-46
Dr. John E. Pinkerton Air Quality Program Manager National Council of the Paper Industry for Air and Stream Improvement, Inc. 260 Madison Ave. New York, New York 10016	D-47
S. J. Eaton Coen Company, Inc. 1510 Rollins Road Burlingame, California 94010	D-48
Bruce P. Clinton Senior Energy Technology Specialist Hercules, Inc. Hercules Plaza Wilmington, Delaware 19894	D-49

Commenter	Docket Reference
Herbert Wortreich Assistant Director, Air and Noise Quality State of New Jersey Department of Environmental Protection John Fitch Plaza CN 027 Trenton, New Jersey 08625	D-50
Bo O. A. Oscarsson Technical Manager Gotaverken Energy Systems P. O. Box 2147 Charlotte, N. C. 28211	D-51
Kathleen M. Bennett Director of Regulatory Affairs Champion International Corporation One Champion Plaza Stamford, Connecticut 06921	D-52
Eric J. Schmidt Senior Environmental Engineer Georgia-Pacific Corporation P. O. Box 105605 Atlanta, Georgia 30348	D-53
L. K. Arehart Supervisor-Regulatory Analysis Health and Environmental Affairs Department Diamond Shamrock Corporation 717 North Harwood Street Dallas, Texas 75201	D-54
H. E. Cameron Plant Environment Environmental Activities Staff General Motors Corporation General Motors Technical Center 30400 Mount Road Warren, Michigan 48090	D-55
H. B. Coffman, Manager Environmental Services Texas Utilities Generating Company Skyway Tower 400 North Olive Street, L.B. 81 Dallas, Texas 75201	D-56

Commenter	Docket Reference
Richard C. Wigger Vice President Environmental and Safety Affairs Champion International Corporation One Champion Plaza Stamford, Connecticut 06921	D-57
N. D. Fitzroy, Manager Energy and Environment Programs General Electric Company Gas Turbine Technology Development & Planning Operation One River Road Schenectady, New York 12345	D-58
Terry McGuire, Chief Technical Support Division California Air Resources Board 1102 Q Street P. O. Box 2815 Sacramento, CA 95812	D-64
Maggie Dean, Director Environmental Affairs American Textile Manufacturers Institute, Inc. 1101 Connecticut Avenue, N.W., Suite 300 Washington, D.C. 20036	D-65
Larry F. Kertcher, Chief Air Compliance Branch (5AC-26) U.S. Environmental Protection Agency Region V	D-70
Michael Baly, III Vice President, Government Relations American Gas Association 1515 Wilson Boulevard Arlington, VA 22209	D-76

TABLE 2-2. LIST OF COMMENTERS ON THE PROPOSED AMENDMENT OF THE NITROGEN OXIDES STANDARD FOR NATURAL GAS/WOOD-FIRED SUBPART D STEAM GENERATING UNITS

Commenter	Docket Reference
James D. Beatty The Procter and Gamble Company 6110 Center Hill Road Cincinnati, Ohio 45224	IV-D-77
William B. Marx, President Council of Industrial Boiler Owners 11222 Silverleaf Drive Fairfax Station, Virginia 22039	D-78
John L. Festa, Ph.D. Director, Chemical Control Program National Forest Products Association/ American Paper Institute 1619 Massachusetts Avenue, N.W. Washington, D. C. 20036	D-79

2.6 Costs/Cost Effectiveness of the Proposed Standards

2.7 Monitoring, Recordkeeping, and Reporting Requirements

2.8 Emission Credits for Cogeneration/Combined Cycle Systems

2.9 Energy, Environmental, and Economic Impacts

2.10 Miscellaneous Comments

2.11 NO_x Emission Limits for Wood Residue and Natural Gas-Fired Units

2.1 APPLICABILITY OF THE STANDARD

2.1.1 General

1. D-17

Comment: EPA is correct in exempting modified sources from the NO_x emission limits.

2. D-38

Comment: EPA has no statutory authority to exempt modified steam generating units from the NO_x standards. NO_x control techniques can be retrofitted to steam generating units.

3. D-8, D-34, D-58

Comment: The proposed NO_x emission limits would apply to gas turbine emissions when these turbines are employed in cogeneration systems.

4. D-2, D-3

Comment: Steam generating units firing municipal solid waste would be subject to both 40 CFR Part 60 Subpart Db and 40 CFR Part 60 Subpart E.

5. D-2

Comment: The applicability of the regulation to sewage sludge incinerators which generate steam should be addressed.

6. D-2

Comment: Sewage sludge incinerators and incinerators subject to 40 CFR Part 60 Subpart E should be excluded from 40 CFR Part 60 Subpart Db.

7. D-2

Comment: The emission limits for solid waste-fired steam generating units should be expressed in a concentration format because it is difficult to accurately measure the heat input for these steam generating units.

8. D-19, D-22, D-28, D-30, D-37

Comment: NO_x emission limits for combustion of municipal solid wastes should not be included in the final standard, but treated on case-by-case basis by State and local agencies. The composition of municipal solid waste varies too widely to set a specific emission limit.

9. D-8, D-36

Comment: EPA has not adequately studied the emission characteristics of chemical waste incinerators. There is a wide variety of industrial incinerators currently in use. The definition of incinerators is too broad and is inconsistent with prior definitions of steam generating units.

10. D-2

Comment: The precise definition of a municipal solid waste incinerator should be addressed in the regulation for purposes of defining prevention of significant deterioration (PSD) applicability.

2.1.2 Process Units

1. D-7

Comment: The definition of steam generating unit should be modified to exclude process heaters that produce steam in waste heat economizers for energy conservation purposes. These sources should be covered in the NSPS for fired heaters in the petroleum refining and petrochemical industries.

2. D-9

Comment: Sources where low excess air (LEA) operation is not appropriate should be exempted from the NO_x emission limits. These would include certain process units such as carbon monoxide (CO) steam generating units where fossil fuels are fired as supplementary fuels. Process units are subject to variations in process conditions and have several sources of heat input. LEA operation may not be applicable to these units.

3. D-9

Comment: Sulfur recovery unit feed gas would be included in the definition of natural gas. This would make Claus units subject to the regulation. LEA technology is not applicable to Claus units because the amount of air used for combustion is only one-third of the theoretical requirement.

4. D-19

<u>Comment</u>: The proposed NSPS appears to unfairly penalize auxiliary gas-fired units (energy recovery units) compared to straight incineration and non-heat recovery units by establishing stringent emission limits for auxiliary gas-fired units and exempting non-heat recovery units.

5. D-29

<u>Comment</u>: EPA has not considered the operating parameters and source characteristics of thermal heat recovery oxidation (THROX) units. THROX units destroy toxic and non-toxic wastes, recover hydrochloric acid and sodium bicarbonate solution, and generate heat for use in process plants. THROX units utilize technology which is very different from conventional steam generating units or incinerators. Because these units both generate steam and destroy "hard to destroy" wastes, they should be treated as a distinct source category. NO_x emissions from THROX units are typically in the 25 to 50 ppm range. In meeting the proposed NO_x emission limits, the ability of THROX units to destroy wastes and recover materials would be limited.

6. D-34

<u>Comment</u>: Do the proposed standards apply to fluid catalytic cracking units?

7. D-34

<u>Comment</u>: EPA's treatment of CO steam generating units in 60.43b(a) and (b) is unclear. The formulas provided do not contain any terms for NO_x emissions from CO burning. Would CO steam generating units be required to meet the proposed limit for natural gas firing?

2.1.3 <u>Mixed Fuel-Fired Units</u>

1. D-3

<u>Comment</u>: It is not clear whether and how the emission limits identified as (6) or (7) in the table of 60.43b(a) would apply to sources firing a mixture of fuels.

2. D-16, D-36, D-42

<u>Comment</u>: Firing of solid industrial waste in combination with fossil fuels should be exempted from the regulations or covered under a separate category.

3. D-18, D-37, D-40, D-47, D-49, D-53, D-57

<u>Comment</u>: The 5 percent annual fossil fuel capacity factor criterion suggested by EPA for exclusion from the NO_x monitoring and emission standards is not realistic because it does not account for the limitations on system burndown ratios, or for the need to periodically increase fossil fuel use to account for fluctuations in load and fuel characteristics. Steam generating unit stability requires fossil fuel use of at least 10 percent.

4. D-57

Comment: Steam generating units burning combinations of gas/oil/coal and wood should be exempt from the NO_x standards if the annual fossil fuel capacity factor is less than 25 percent.

2.1.4 Fuel Definitions/Exclusions

1. D-30, D-37, D-42, D-45, D-49

Comment: Black liquor recovery steam generating units, coal/water slurries, coal/oil slurries, and micronized coal should be explicitly exempted from the regulations.

2. D-9, D-30, D-36, D-37, D-42, D-45, D-49, D-54

Comment: The existing definition of "natural gas" is too broad, and should be revised to exclude other gaseous materials.

3. D-30

Comment: The definition of wood should be revised to include only natural wood products without additives, drying, sizing, and with a moisture content of between 40 and 50 percent and a nitrogen content of greater than 0.4 percent (dry).

4. D-15, D-34, D-36, D-37, D-38

Comment: The definition of "other fuels" is too vague. Emission limits for these fuels should be determined on a case-by-case basis.

5. D-20

Comment: Units burning bagasse should be explicitly exempted from the regulations.

6. D-18, D-37

Comment: The proposed standard appears to cover wood gasification and combustion of that gas, but no data are presented. Gaseous and liquid products from wood and other forms of biomass should be excluded from the standard until data become available.

7. D-18

Comment: Firing of pulverized wood fines should be exempt from the regulations because no data are available on emissions from units firing this fuel.

8. D-27, D-29, D-37, D-45, D-54

Comment: Combined cycle/cogeneration systems should be exempted from the proposed NO_x emission limits.

9. D-29

Comment: No definition is provided for incinerators.

10. D-29

Comment: Thermal heat recovery oxidation (THROX) units should be exempted from the proposed standards.

11. D-32, D-35, D-56

Comment: Auxiliary steam generating units at steam-electric plants should be exempted from the standards. These steam generating units are infrequently operated and do not contribute significantly to emissions.

12. D-34

Comment: Plant produced fuel gas can contain elevated nitrogen concentrations and a waiver should be granted by EPA for this difference in NO_x emissions.

13. D-37

Comment: Steam generating units burning any type of agricultural wastes should be exempted from the proposed standard. No data are available to support standards, and emissions from burning these wastes are minimal.

14. D-37

Comment: The definition of coal is too broad. Data are unavailable to support standards for units burning coal-derived fuels. The definition of coal should be restricted to established coal forms and firing methods.

15. D-37

Comment: Incinerators should be excluded from the proposed standards.

16. D-54

Comment: Heat recovery steam generating units should be exempted from the proposed regulations.

17. D-16, D-30, D-34, D-36, D-37, D-39, D-42, D-45, D-49

Comment: Gaseous and liquid byproduct fuels should be deleted from the definitions of natural gas and residual oil. The emissions and combustion characteristics of these fuels are too variable to justify their inclusion in the proposed standards for fossil oil and gas.

2.1.5 Size Cutoff

1. D-6, D-12, D-31

Comment: EPA is correct in establishing NSPS for steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range because the States have been reluctant to set stringent emission limits for these units in the absence of NSPS.

2. D-11, D-18, D-40, D-42, D-47, D-57

Comment: The NSPS for steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range are not warranted given the relatively small contribution to emissions from these sources. State regulations are sufficient to meet the regulatory needs of these steam generating units.

3. D-11, D-57

Comment: It would be "arbitrary and unlawful" for EPA to promulgate NSPS for steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range without first formally denying requests that these size units be delisted.

4. D-38

Comment: It would be unlawful for EPA to regulate steam generating units only down to 29 MW (100 million Btu/hour) heat input capacity because EPA has previously identified steam generating units as small as 2.9 MW (10 million Btu/hour) heat input capacity to be major sources.

5. D-50

Comment: The lower limit on capacity of affected steam generating units is too high and should be set at 15 MW (50 million Btu/hour) heat input capacity. Steam generating units in the 15 to 29 MW (50 to 100 million Btu/hour) heat input capacity range are similar in design to those in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range, make up a similar fraction of the total steam generating unit population, and have similar fuel use patterns.

2.2 SELECTION/PERFORMANCE OF DEMONSTRATED NO_x CONTROL TECHNOLOGY

2.2.1 General

1. D-9, D-30, D-48

Comment: Low excess air (LEA) technology should form the technological basis of the proposed standards for NO_x rather than add-on control technology. The LEA technology results in no additional capital or operating costs, saves energy, does not result in increased emissions of other pollutants, and is effective at all generating loads.

2. D-16, D-24, D-25, D-30, D-36, D-37, D-42, D-43, D-46, D-48, D-49

Comment: The EPA has made broad and sweeping conclusions as to the performance of control technologies on the basis of limited test data. Sufficient data have not been developed to support emission limits for all the fuels and fuel combinations the proposal intends to regulate.

3. D-29, D-30, D-36, D-37, D-42, D-48

Comment: Staged combustion (SC) has not been adequately demonstrated in reducing NO_x emissions from steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range, and there are insufficient data to support emission standards based on SC controls. Specifically, (1) SC technology has not been adequately demonstrated for high heat release package steam generating units burning residual oil with a nitrogen content of 0.2 to 0.4 weight percent, (2) SC has not been adequately demonstrated on spreader-stokers, (3) SC has been shown to be ineffective in reducing NO_x emissions under reduced load operation for all steam generating unit/fuel arrangements.

4. D-30, D-37, D-48

Comment: The correlations established for predicting the emission reductions achievable by SC are in error because (1) data from all different types of steam generating units were grouped together, (2) the majority of data are for small package units or large field erected units, (3) a number of data points were obtained from units operating with high excess air and the method used to normalize emission data to a baseline oxygen level is subject to error, and (4) virtually all of the data for SC operation were obtained from furnaces with long residence times and low heat release rates, and these data cannot be generalized to high heat release package steam generating units.

5. D-30

Comment: The EPA is incorrect in stating that flue gas recirculation (FGR) achieves little reduction in NO_x beyond that achievable with LEA. FGR is most effective in suppressing thermal NO_x formation from combustion of gas and distillate oil and can achieve a reduction in NO_x emissions of more than 30 percent. Drawing conclusions from tests on two small FGR-equipped units [less than 15 MW (50 million Btu/hour) heat input capacity] is difficult, and demonstrates the need for a larger data base in determining demonstrated technology.

6. D-25, D-29, D-30, D-33, D-36, D-37, D-42, D-48

Comment: The EPA has given inadequate consideration to variations in steam generating unit design and the effect of these design variations on NO_x emissions, particularly those relating to firebox design, heat release rate, and other factors relating to steam generating unit size.

7. D-9, D-37

Comment: The EPA was correct in mathematically correlating NO_x emission reductions with steam generating unit operating variables. However, EPA should demonstrate that these correlations are representative of the actual population of steam generating units that EPA intends to regulate. Case-by-case determinations should be allowed for steam generating units which are not representative.

8. D-9

Comment: Performance of NO_x controls may decline with increasing equipment age. The EPA tests were probably conducted on relatively new equipment and the emission limits may not account for declining performance due to age.

9. D-25, D-37

Comment: Large package steam generating units may have to be derated by up to 30 percent to meet the proposed standard because of limitations on firebox size. The Agency derating estimate of 7 percent is an underestimate.

10. D-25, D-26, D-36, D-37

Comment: The "vendor guarantees" cited by EPA can not be used as a basis for determining best demonstrated technology because these do not represent actual contracts between buyers and sellers, and many of these guarantees apply only to the extreme lower size of the steam generating units to be regulated.

11. D-32

Comment: Only one of five vendors would guarantee a NO_x emission limit of 43 ng/J (0.1 lb/million Btu) heat input for a distillate oil-fired unit. This is insufficient for determining best demonstrated technology and has potential antitrust ramifications.

12. D-15, D-25

Comment: Vendors of steam generating units and burner equipment are unable to guarantee an emission limit of 43 ng/J (0.1 lb/million Btu) heat input will be achieved when firing natural gas or distillate oil.

13. D-38

Comment: The EPA has ignored the fact that various types of flue gas treatment technologies have been demonstrated in controlling NO_x emissions from oil- and coal-fired steam generating units. These systems should be used as the basis for setting the standards.

14. D-38

Comment: The proposed standards do not reflect the level of control achievable by low excess air/staged combustion/staged combustion burner (LEA/SC/SCB) technologies (lower emission limits are justified).

15. D-37, D-49

Comment: Background data obtained over a 30-day test period should not be relied upon as representative of long-term operating conditions. NO_x emissions can fluctuate due to process load swings, changes in fuel characteristics, automatic control deviations, and time.

2.2.2 Coal-Fired Steam Generating Units

1. D-16, D-25, D-30, D-36, D-37, D-42, D-49

Comment: Insufficient emission test data are available to support the proposed NO_x emission limit of 301 ng/J (0.7 lb/million Btu) heat input for pulverized coal-fired steam generating units. No test data were provided for pulverized coal-fired steam generating units of less than 88 MW (300 million Btu/hour) heat input capacity. Pulverized coal-fired steam generating units of less than 73 MW (250 million Btu/hour) heat input capacity are designed substantially differently (i.e., wall-fired) than larger pulverized coal-fired steam generating units (i.e., tangentially-fired).

2. D-33

Comment: The proposed standards have not considered fluidized bed combustion (FBC) as a demonstrated control technology. Based on 2-year operating data with atmospheric fluidized bed combustion (AFBC) units, NO_x emissions of 172 ng/J (0.4 lb/million Btu) heat input are achievable when burning eastern bituminous coal.

3. D-31

Comment: Pulverized coal-fired steam generating units can reduce emissions of NO_x to below the proposed limit of 301 ng/J (0.7 lb/million Btu) heat input. One unit was tested and found to emit 84 ng/J (0.195 lb NO_x/million Btu) heat input.

4. D-25, D-33, D-37, D-43

Comment: The NO_x emission limit for coal firing should allow for differences between firing bituminous and subbituminous coal. Such allowances are provided in the NSPS for steam-electric plants.

5. D-30, D-46

Comment: The EPA does not have sufficient data to substantiate the long-term variation in NO_x emissions from spreader stokers of 7 percent when using a 30-day rolling average. Only two units were equipped with continuous monitors and both of these were operated at light loads and high excess air.

6. D-30

Comment: The EPA is incorrect in concluding that fuel nitrogen content had no measurable effect on NO_x emissions from spreader stoker steam generating units. The test procedures were inadequate to correlate the fuel burned at a given moment to NO_x emissions.

7. D-25, D-30, D-33, D-36, D-37, D-39, D-42

Comment: The EPA is in error in concluding that combustion air preheat has no effect on NO_x emissions from spreader stoker steam generating units. The test data were incorrectly interpreted.

2.2.3 Gas-/Oil-Fired Steam Generating Units

1. D-30

Comment: The relationships between fuel nitrogen content and NO_x emissions is not well established for residual oils, especially the difference between burning residual oil in package steam generating units versus field erected steam generating units.

2. D-7

Comment: Two new (1976) gas-fired steam generating units without combustion air preheat and using LEA at the El Segundo refinery have NO_x emissions of 116 ng/J (0.27 lb/million Btu) heat input. To achieve the proposed emission limit, emissions would have to be reduced by about 63 percent. This exceeds the emission reduction capability of SC/SCB technology, which is normally recognized to be 30 to 45 percent.

3. D-25, D-36, D-37, D-48

Comment: The regression formula relating NO_x emissions to design variables for residual oil firing does not properly address the thermal or the fuel NO_x component. The thermal NO_x component should vary according to heat release to absorbing area and increase with increasing capacity. The values used in the equation for conversion of fuel nitrogen to NO_x are too low.

4. D-25, D-29, D-33, D-36, D-37

Comment: Performance data for two natural gas-fired units equipped with LEA air and overfire air capability are not representative because the units had large heat input capacities [166 and 234 MW (567 and 800 million Btu/hour)].

5. D-25, D-37, D-48

Comment: Performance data for three natural gas-fired units equipped with LEA and SCB are not representative because they had been slightly derated.

6. D-26, D-29, D-32, D-36, D-37

Comment: The data supporting the NO_x emission limit for steam generating units firing gas and distillate oil are not representative because only one long-term test was available and this was on a very small unit [1.5 MW (5 million Btu/hour)] heat input capacity.

7. D-26

Comment: The data supporting the NO_x emission limit for steam generating units firing gas and distillate oil are not representative because the steam generating units with air preheat had relatively low air preheat temperatures.

8. D-26, D-32

Comment: The data supporting the NO_x emission limit for steam generating units firing gas and distillate oil are not representative because of the wide scatter seen among the individual data points. Given this variability, EPA should not have relied on average values.

9. D-29, D-30, D-33, D-36, D-37, D-42, D-49

Comment: The EPA did not adequately assess the effect of combustion air preheat on NO_x emissions from gas- and distillate oil-fired steam generating units.

10. D-29, D-36, D-37

Comment: The EPA did not consider the effect of the nitrogen content of distillate oil on NO_x emissions from distillate oil-fired steam generating units.

11. D-32, D-33, D-36, D-37, D-42

Comment: Low excess air/staged combustion burner technology has not been demonstrated to reduce emissions from distillate oil-fired steam generating units to 43 ng/J (0.1 lb/million Btu) heat input.

12. D-55

Comment: The NO_x standards for gas- and oil-fired steam generating units are based on a minimal amount of test data and appear impossible to meet on a continuous basis.

2.2.4 Other Steam Generating Units

1. D-16, D-30, D-37, D-39

Comment: Insufficient data are available to determine best demonstrated technology for units firing combinations of fossil and nonfossil fuels.

2. D-22, D-28

Comment: State requirements for minimum temperatures and residence times for destruction of organics in incinerators burning municipal solid waste would prevent these units from achieving the proposed limits on NO_x emissions.

3. D-28

Comment: Municipal solid waste incinerators would have to install scrubbers in order to reduce NO_x emissions to 129 ng/J (0.3 lb/million Btu) heat input. The costs of these systems have not been addressed.

4. D-34

Comment: NO_x control technologies for steam generating units may not be effective for turbines, particularly those firing distillate oil.

5. D-8, D-30, D-54

Comment: The EPA has insufficient background information on which to establish NSPS for combined cycle systems. No parametric data on effects of excess air, overfire air, system design or duct-firing have been obtained. Combined cycle systems should be evaluated as a separate source category.

2.3 STRINGENCY OF THE NO_x EMISSION LIMITS

1. D-23, D-42, D-57

Comment: There is no compelling reason to establish NSPS for NO_x emissions from small steam generating units. Only one area in the U.S. is not in attainment with the National Ambient Air Quality Standards (NAAQS) for NO_x.

2.3.1 Gas-/Distillate Oil-Fired Steam Generating Units

1. D-29, D-30, D-37, D-48

Comment: The proposed emission limits are unrealistic and should be raised to 86 ng/J (0.2 lb/million Btu) heat input for distillate fuel oil (less than 0.05 percent nitrogen) and for gas burning with ambient combustion air. Gas-fired units with preheated combustion air should be limited to 108 ng/J (0.25 lb/million Btu) heat input.

2. D-7

Comment: The proposed emission limit is too stringent and should be raised to between 65 and 86 ng/J (0.15 and 0.20 lb/million Btu) heat input. The proposed emission limit exceeds the emission reduction capacity of LEA/SC/SCB control technology.

3. D-9

Comment: The emission limits should be set at 86 ng/J (0.2 lb/million Btu) heat input for natural gas-fired units and 129 ng/J (0.3 lb/million Btu) heat input for distillate oil-fired units. These levels can be met by using LEA alone.

4. D-15, D-26

Comment: The proposed gas/distillate oil emission limit is too stringent and should be raised to 86 ng/J (0.2 lb/million Btu) heat input.

5. D-33

Comment: A NO_x standard of 86 ng/J (0.2 lb/million Btu) heat input for non-preheat gas/distillate oil firing would be supported by commercial guarantees.

6. D-33

Comment: A NO_x standard of 108 ng/J (0.25 lb/million Btu) heat input for greater than 93°C (200°F) preheat gas/distillate oil firing would be supported by commercial guarantees.

2.3.2 Residual Oil-Fired Steam Generating Units

1. D-29, D-30, D-37, D-48

Comment: The proposed NO_x emission limits for residual oil firing should be raised to 172 ng/J (0.4 lb/million Btu) heat input for low nitrogen oils and to 215 ng/J (0.5 lb/million Btu) heat input for oil with a high nitrogen content. The proposed limits would prematurely force most residual oil-fired units to implement SC, which has not been properly developed for large package units.

2. D-33

Comment: A NO_x emission limit of 215 ng/J (0.5 lb/million Btu) heat input for high nitrogen (greater than 0.35 percent) residual oil firing would be supported by commercial guarantees.

3. D-33

Comment: A NO_x emission limit of 172 ng/J (0.4 lb/million Btu) heat input for low nitrogen (less than 0.35 percent) residual oil firing would be supported by commercial guarantees.

4. D-38

Comment: The data show that even high nitrogen residual oil-fired steam generating units could achieve a 30-day average emission rate of 129 ng/J (0.3 lb/million Btu) heat input.

5. D-54

Comment: The emission limits for residual oil firing should not vary with the fuel nitrogen content. Fuel nitrogen varies widely on the basis of crude oil supplies and is expensive to monitor.

2.3.3 Mass Feed Coal-Fired Steam Generating Units

1. D-33

Comment: The proposed emission limit would be supported by commercial guarantees.

2. D-37

Comment: The NO_x emission limit for mass feed coal-fired steam generating units should be 215 ng/J (0.5 lb/million Btu) heat input.

2.3.4 Spreader Stoker Coal-Fired Steam Generating Units

1. D-27, D-29, D-30, D-37, D-39

Comment: Spreader stoker steam generating units operating with preheated combustion air cannot achieve a NO_x emission limit of 258 ng/J (0.6 lb/million Btu) heat input. The emission limit should be raised to 301 ng/J (0.7 lb/million Btu) heat input. It was noted that the proposed limit would force spreader stokers with preheated combustion air to be designed for very low heat release rates, which would raise costs and thus encourage pulverized coal (PC) firing. The proposed emission limit for PC firing is 301 ng/J (0.7 lb/million Btu) heat input.

2. D-33

Comment: A NO_x emission limit of 301 ng/J (0.7 lb/million Btu) heat input for air preheat spreader stoker coal firing would be supported by commercial guarantees.

3. D-33

Comment: A NO_x emission limit of 258 ng/J (0.6 lb/million Btu) heat input for non-air preheat [less than 93°C (200°F)] spreader stoker coal firing would be supported by commercial guarantees.

4. D-38

Comment: The 11 percent upward adjustment of the long-term test data is not representative of the other units tested and the emission level should be lowered to between 172 and 215 ng/J (0.4 and 0.5 lb/million Btu) heat input.

2.3.5 Pulverized Coal-Fired Steam Generating Units

1. D-29, D-30, D-37, D-48

Comment: The NO_x emission limit for pulverized coal-fired steam generating units should be raised to 344 ng/J (0.8 lb/million Btu) heat input. Although LEA/SC can reduce emissions from units smaller than 73 MW (250 million Btu/hour) heat input capacity, a reduction to 301 ng/J (0.7 lb/million Btu) heat input cannot be achieved. In small units, higher flame temperatures must be maintained to achieve complete combustion because of smaller volume-to-surface area ratios. These conditions result in higher NO_x emissions.

2. D-33

Comment: A NO_x emission limit of 344 ng/J (0.8 lb/million Btu) heat input for pulverized coal firing would be supported by commercial guarantees.

3. D-38

Comment: Data collected by EPA/IERL show an emission rate of 172 ng/J (0.4 lb/million Btu) heat input can be achieved using low NO_x burners.

2.3.6 Multiple Fuel Units

1. D-30

Comment: More leeway must be provided in determining NO_x emission limits for units burning multiple fossil fuels.

Multiple fuel steam generating units are designed according to the most difficult fuel to be burned. Because of this, NO_x emission control techniques are compromised in a multiple fuel-firing situation. It is unreasonable to expect optimum NO_x control when both clean and dirty fuels are fired in a unit designed primarily in accordance with the requirements for burning the more difficult to burn (dirty) fuels. Therefore, the limits should not be based on the lowest achievable NO_x emissions for individual fuels in a multiple fuel unit.

2. D-29, D-30, D-36, D-39, D-42, D-54

Comment: Insufficient data are available to regulate emissions from units burning a combination of fossil fuels and chemical byproduct gaseous and liquid wastes, particularly waste fuels such as hydrogen gas, ammonia bearing gas, liquids with high nitrogen content, and high heat content fuels (greater than 1,500 Btu/ft). In many instances, the applicable fossil fuel-based NO_x limit could not be met.

3. D-16, D-30, D-36, D-37, D-39

Comment: Insufficient data are available to justify NO_x emission limits for units firing nonfossil fuels and mixtures of nonfossil and fossil fuels.

4. D-57

Comment: A nonfossil fuel steam generating unit designed to burn gas and residual oil would be designed to fire either fuel at the same rate. Thus, if the weighted average were applied, the applicable emission limit would be 86 ng/J (0.2 lb/million Btu) heat input. A steam generating unit burning gas or residual oil in combination with wood or solid waste should not be restricted to 86 ng/J (0.2 lb/million Btu) heat input when a combination with distillate oil would be allowed to emit 129 ng/J (0.3 lb/million Btu) heat input. A nonfossil steam generating unit burning gas and residual oil in combination should be allowed a NO_x limit equivalent to that for residual oil-fired steam generating units.

2.3.7 Combined Cycle Systems

1. D-30, D-48

Comment: The emission limit for combined cycle units should be raised to 86 ng/J (0.2 lb/million Btu) heat input for units burning gas and distillate oil and should be deferred for units firing residual oil.

2.4 SELECTION/PERFORMANCE OF DEMONSTRATED PARTICULATE MATTER CONTROL TECHNOLOGY

1. D-4

Comment: A specific collection area (SCA) of greater than 250 ft^2/1,000 acfm will not assure that the proposed standard will be met. Data from one plant indicated that a particulate matter emission level of 65 ng/J (0.15 lb/million Btu) heat input is achievable on a continuous basis with existing technology. The standard must account for soot blowing.

2. D-13

Comment: Electrostatic precipitators are capable of reducing particulate matter emissions from combination coal-/wood-fired steam generating units to 86 ng/J (0.02 lb/million Btu) heat input.

3. D-4

Comment: Insufficient data are available to set NSPS for particulate matter emissions from municipal solid waste/refuse derived fuel-fired steam generating units (MSW/RDF). The EPA did not test enough facilities to account for typical emissions variability, or test any facilities burning up to 50 percent MSW.

4. D-4

Comment: Variability in fuel characteristics (moisture, ash, heat content) which is 2 to 3 times higher for MSW/RDF than for other fuels causes corresponding variabilities in emissions and control device performance. Particulate matter emissions ranged from 22 to 56 ng/J (0.05 to 0.13 lb/million Btu) heat input and averaged 39 ng/J (0.09 lb/million Btu) heat input (standard deviation = 0.03). Periodic (greater than 6 min/hour) soot blowing is also required which increases particulate matter emissions by about 80 percent.

5. D-31

Comment: Two MSW incinerators equipped with ESP's (300 ft^2/1,000 cfm) achieved emission rates of 13 and 17 ng/J (0.03 and 0.04 lb/million Btu) heat input. State of the art control technologies can reduce emissions from MSW incinerators to less than 43 ng/J (0.1 lb/million Btu) heat input.

6. D-31, D-38

Comment: The "relaxed" emission levels allowed for units operating at capacity factors of less than 30 percent do not represent application of best demonstrated technology.

7. D-31, D-38

Comment: Based on EPA's own admission, ESP's are capable of reducing emissions from units firing mixed fuels to less than 43 ng/J (0.1 lb/million Btu) heat input.

8. D-38

Comment: The EPA's conclusion that fabric filters and ESP's cannot achieve better than 22 ng/J (0.05 lb/million Btu) heat input on coal-fired steam generating units is arbitrary, capricious, and is not supported by the data available to EPA. The EPA has previously determined, and defended in court, that emissions of 13 ng/J (0.03 lb/million Btu) heat input are achievable based on data from both utility and industrial steam generating units. The few test data showing emissions higher than 13 ng/J (0.03 lb/million Btu) heat input were from ESP's having SCA's less than that considered to represent best demonstrated technology (650 ft^2/1,000 acfm). All of the data on the fabric filter systems support an emission limit of 13 ng/J (0.03 lb/million Btu) heat input. The Unit C system was not a well designed and operated system and test data on this system included soot blowing cycles.

9. D-50

Comment: Particulate matter emissions from wood-fired steam generating units can be controlled to less than 43 ng/J (0.1 lb/million Btu) heat input.

2.5 STRINGENCY OF THE PARTICULATE MATTER EMISSION LIMITS

1. D-24, D-57

Comment: The emission limits for particulate matter are too stringent.

2. D-31

Comment: The emission limit for coal-fired steam generating units of 22 ng/J (0.05 lb/million Btu) heat input is appropriate.

3. D-31, D-38

Comment: The proposed emission limit for municipal waste incinerators is too lenient and does not reflect best demonstrated technology.

4. D-31, D-38

Comment: The proposed emission limits for units operating at less than 30 percent capacity factors are far too lenient. A capacity factor of 30 percent does not reflect a "standby" or sparingly used unit.

5. D-31

Comment: The proposed emission limits for mixed fuel firing as specified in 60.42b(c) are too lenient and should be lowered to 30 ng/J (0.07 lb/million Btu) heat input.

6. D-38

Comment: The proposed emission limit of 22 ng/J (0.05 lb/million Btu) heat input for coal-fired steam generating units is too lenient, and should be lowered to 13 ng/J (0.03 lb/million Btu) heat input.

7. D-38

Comment: Wood-fired steam generating units equipped with electrostatic granular filters (EGF) can achieve emissions of 9 to 17 ng/J (0.02 to 0.04 lb/million Btu) heat input. The EPA has not justified setting a higher standard.

8. D-38

Comment: In the absence of any theoretical or empirical data to show that mixed solid fuel steam generating units cannot achieve the same emission levels as coal-fired steam generating units, EPA should not propose separate emission limits for these sources. The 5 percent mixed fuel criterion will encourage owners and operators to burn these fuels in order to be subject to a less stringent emission limit.

9. D-50

Comment: The proposed emission limit of 43 ng/J (0.1 lb/million Btu) heat input for wood-fired steam generating units is too lenient. Although wood is not widely burned, the proposed emission limit fails to consider the emission impact of the proposed standard in the areas near wood burning sources.

10. D-55

Comment: The particulate matter emission limit of 22 ng/J (0.05 lb/million Btu) heat input for coal-fired steam generating units prohibits the use of wet scrubbers which may be required for standards covering emissions of sulfur dioxide.

11. D-37

Comment: The following particulate matter emission limits are recommended for steam generating units in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range:

- Mass feed spreader stoker, 108 ng/J (0.25 lb/million Btu) heat input;
- Pulverized coal, 43 ng/J (0.1 lb/million Btu) heat input.

For steam generating units above 73 MW (250 million Btu/hour) heat input capacity, a particulate matter emission limit of 43 ng/J (0.1 lb/million Btu) heat input should be set for coal and residual oil firing.

12. D-12

Comment: The proposed particulate matter emission levels are appropriate.

2.6 COSTS/COST EFFECTIVENESS OF THE PROPOSED STANDARDS

1. D-7, D-25, D-30, D-36, D-37, D-39

Comment: The EPA has used steam generating units without low excess air (LEA) controls as the basis for calculating the cost effectiveness of NO_x controls. Fuel savings from LEA operation were credited to the costs of NO_x controls. This is inappropriate because new units will be operated under LEA conditions even in the absence of an NSPS. The EPA's approach understates the real cost effectiveness of the proposed regulation.

2. D-15, D-36

Comment: The costs of meeting the proposed NO_x emission limits are largely undefined because manufacturers do not presently offer steam generating units guaranteed to meet a 43 ng/J (0.1 lb/million Btu) heat input emission limit.

3. D-18, D-24, D-26, D-27, D-29, D-40, D-45, D-46, D-49, D-53

Comment: The costs of NO_x continuous emission monitoring systems (CEMS) are excessive for steam generating units in the

29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range.

4. D-18, D-53

Comment: Steam generating units using between 5 and 30 percent of fossil fuel input without a permanent NO_x monitor will be required to perform an expensive 30-day NO_x compliance test. The costs of this test will not be commensurate with the air quality benefits obtained.

5. D-18, D-24

Comment: The cost effectiveness of controls for small steam generating units is 20 to 40 times higher than that for utility steam generating units, and represents a poor use of limited capital for environmental protection.

6. D-23

Comment: The EPA estimates show that the cost of implementing the standard may be as high as $2,000/Mg ($1,800/ton) of NO_x removed, but EPA has also estimated the benefits of NO_x control are only $150/Mg ($135/ton).

7. D-25, D-37, D-43

Comment: EPA has grossly underestimated the capital and operating costs of CEMS equipment. Capital costs are about $125,000 and annual costs are about $100,000.

8. D-25, D-37

Comment: The cost effectiveness of the proposed NO_x standard for a gas-fired 44 MW (150 million Btu/hour) heat input capacity unit would be $3,000/Mg ($2,700/ton) removed, assuming the use of a low NO_x burner, baseline LEA operation, a 7 percent derating, and revised monitoring costs. The costs are unreasonable.

9. D-25, D-37

Comment: The cost effectiveness of the proposed NO_x standard for a residual oil-fired 44 MW (150 million Btu/hour) heat input capacity unit would be $2,800/Mg ($2,500/ton) for 0.3 percent fuel nitrogen, and $4,400/Mg ($4,000/ton) for 0.4 percent fuel nitrogen, assuming the use of overfire air ports, baseline LEA operation, a 7 percent derating, and revised monitoring costs. These costs are unreasonable.

10. D-27

Comment: The costs for NO_x CEMS are $110,000 in capital costs and $50,000 in annual operating costs. In addition, a microprocessor would be required to calculate 30-day rolling averages at a cost of $80,000.

11. D-31

Comment: The EPA has placed too much reliance on cost and economic factors in establishing the proposed emission limits.

12. D-32, D-35

Comment: It is not cost effective to require low excess air/staged combustion burner (LEA/SCB) controls on steam generating units with capacity factors of less than 30 percent.

13. D-36, D-39, D-46

Comment: The EPA has not presented cost effectiveness numbers in Tables 9 to 14 of the proposal in a manner which is meaningful for comparing alternative control levels. The incremental cost effectiveness between alternative control levels should be shown.

14. D-36, D-39

Comment: The cost effectiveness numbers of pulverized coal firing in Table 9 are misleading because EPA has used the costs of a low efficiency ESP instead of the costs for a sidestream separator or a double mechanical collector.

15. D-36, D-37, D-45

Comment: The cost effectiveness of particulate matter control for coal-fired steam generating units are out of proportion to the cost effectiveness for utility size units. The EPA should justify why a cutoff in cost effectiveness of \$110/Mg (\$100/ton) should not be established.

16. D-38

Comment: Cost effectiveness calculations should be based on the actual expected performance of the best demonstrated systems in reducing emissions rather than on the emission limits themselves.

17. D-38

Comment: EPA has not established that operating a CEMS for NO_x emissions would be unreasonably costly for units operating at an annual capacity factor of less than 30 percent.

18. D-37, D-45

Comment: The NO_x emission limits should be revised to be of comparable cost effectiveness as those for utility size steam generating units.

19. D-30, D-46, D-55, D-57

Comment: The cost effectiveness of the proposed standards for particulate matter (coal/wood) are underestimated because the baseline emissions levels used by EPA [258 ng/J (0.6 lb/million Btu) heat input] are higher than the actual emission levels generally allowed from these sources by State regulations.

20. D-37

Comment: The EPA has grossly underestimated the costs of control of NO_x. A steam generating unit derating of 30 percent will be required in many cases. The monitoring requirements were underestimated by one-half. There will be no fuel savings with low NO_x burners. The actual cost effectiveness of the standard for a 44 MW (150 million Btu/hour) heat input capacity natural gas-fired steam generating unit is over $8,300/Mg ($7,500/ton). The actual cost effectiveness of controlling a residual oil-fired steam generating unit (0.4 percent nitrogen) is $5,500/Mg ($5,000/ton). The actual cost effectiveness of controlling a residual oil-fired steam generating unit (0.3 percent nitrogen) is $8,800/Mg ($8,000/ton).

21. D-37

Comment: The EPA must quantify the benefits of any proposed standards.

22. D-37

Comment: Cost effectiveness data for residual oil-fired units are presented for oils with 0.47 and 0.6 percent nitrogen. Because the standard distinguishes residual oil with less than 0.35 percent nitrogen, cost effectiveness data for this oil should be provided.

23. D-27

Comment: Capital costs, including installation, for a transmissometer for continuous opacity monitoring are approximately $40,000. These costs are unreasonable.

2.7 MONITORING, RECORDKEEPING AND REPORTING REQUIREMENTS

2.7.1 Continuous NO_x Emission Monitoring Systems

1. D-5, D-39, D-40, D-47, D-54

Comment: Steam generating units having an annual capacity factor greater than 30 percent should not be required to install and operate a NO_x CEMS if, during a 30-day performance test, NO_x emission levels of 30 percent (or 10 percent, D-47) or more below the applicable limit are demonstrated. This would be consistent with 40 CFR Part 60 Subpart D requirements.

2. D-7, D-27, D-43, D-47, D-49

Comment: Monitoring of operating conditions should be allowed for all units regardless of capacity factor. NO_x emissions can be reliably predicted for LEA, SC, and SCB controls once excess oxygen, optimum staging ratios, and load response curves are established. These parameters can be established during the 30-day performance test and be subject to approval by the Administrator. This approach would avoid the financial, maintenance, and operating problems associated with installing a NO_x monitor on top of the O_2/CO monitors used in LEA systems.

3. D-8, D-21

Comment: NO_x monitors installed on combined cycle units will measure emissions from both the steam generating unit and the turbine unless two monitors are installed (inlet and outlet of steam generating unit) to determine incremental NO_x formed in the steam generating unit. The EPA has not investigated costs or accuracy of twin monitoring systems.

4. D-18, D-24, D-47, D-49, D-53, D-55

Comment: Most smaller manufacturing facilities which would be subject to the NSPS do not have personnel capable of operating, calibrating, and maintaining NO_x CEMS.

5. D-23, D-33, D-49, D-54

Comment: Continuous NO_x monitors are unreliable.

6. D-23, D-24, D-29, D-37, D-40, D-43, D-49, D-53, D-55

<u>Comment</u>: The continuous monitoring requirements for NO_x emissions are unnecessary and excessive.

7. D-24, D-26, D-27, D-33, D-37, D-55

<u>Comment</u>: EPA Reference Method 7 is sufficient for determining compliance with the NO_x emission limits.

8. D-24, D-39

<u>Comment</u>: The proposed requirement that malfunctioning CEMS equipment must be repaired within 15 days is unrealistic because of the sophisticated nature of this equipment, and the possible need to return the device to the manufacturer.

9. D-26

<u>Comment</u>: If CEMS are required, provisions should be made to allow owners/operators to remove CEMS if after a sufficient period (2 years) emissions have not exceeded the limits.

10. D-50

<u>Comment</u>: The proposed NO_x monitoring requirements should be retained in the promulgated standards because major increases in NO_x emissions in the future will create the need for better information on NO_x control.

11. D-53

<u>Comment</u>: The language currently in 40 CFR 60.45(b)(3) and (4) would provide adequate assurance that a new source was designed, manufactured, installed, and operated in a manner to achieve the proposed NO_x emission limits.

12. D-54

<u>Comment</u>: It is not clear why EPA chose to adopt the 30-day rolling average for NO_x compliance. The data seem to support a figure more than 8 percent above the 43 ng/J (0.1 lb/million Btu) heat input emission limit. If this is true, EPA should set the limit at 52 ng/J (0.12 lb/million Btu) heat input or greater and retain the existing compliance methods.

13. D-9

<u>Comment</u>: A NO_x CEMS should not be required for gas and/or oil-fired steam generating units with less than 73 MW (250 million Btu/hour) heat input capacity. Stack testing at suitable intervals should be an alternative to installation of continuous NO_x monitors.

14. D-21

<u>Comment</u>: An exemption from the NO_x CEMS requirement is recommended for combined cycle supplementary-fired gas turbine systems with less than 30 percent total heat input from low NO_x duct burners.

2.7.2 <u>Opacity</u>

1. D-3

<u>Comment</u>: The opacity span values of 60 to 80 percent would not allow a determination of the severity of exceedances above the span value. A span value of 100 percent is recommended.

2. D-4

Comment: The opacity limit of 20 percent cannot be achieved continuously for units firing municipal solid waste and refuse derived fuel. Company test data show 6-minute opacity readings from 0 to 60 percent. At average particulate matter emissions of 327 ng/J (0.76 lb/million Btu) heat input, opacity averaged 42 percent for one test run. The EPA data also show greater than 20 percent opacity with particulate matter emissions of 43 ng/J (0.1 lb/million Btu) heat input. Soot blowing increases opacity by 154 percent over non-soot blowing periods.

3. D-5

Comment: Opacity values from in-stack monitoring devices should be used for purposes of determining compliance instead of Reference Method 9. Use of transmissometers would be contingent on proper installation and operation of the device. They would not be applicable for situations where exhaust gases contain condensed water vapor, or where a reaction or condensation plume is noted above the stack.

4. D-5

Comment: When proper reading techniques are utilized, visible emissions evaluations may be obtained from steam generating units equipped with wet scrubbing devices.

5. D-13, D-18, D-47

<u>Comment</u>: An opacity limit of 20 percent cannot be achieved continuously by units burning coal/wood mixtures.

6. D-18

<u>Comment</u>: The 6-minute average opacity limits would not be consistent with the limits on particulate matter emissions expressed as a 3-hour average.

7. D-18, D-30, D-37

<u>Comment</u>: Site-specific opacity limits should be established.

8. D-27

<u>Comment</u>: Visual determination of opacity using Reference Method 9 is an adequate indicator that a particulate matter control device is being properly operated and maintained.

9. D-31

<u>Comment</u>: The proposed opacity limit of 20 percent is too lenient for coal-fired units. Properly operating control devices should result in visible emissions of no more than 5 to 10 percent opacity.

10. D-31

<u>Comment</u>: The proposed opacity limits are assumed to apply to all phases of equipment operation: startup, shutdown, soot blowing, ash removal.

11. D-31

Comment: Control devices operating at elevated temperatures to avoid dew point related problems will have difficulty in meeting the proposed opacity limits during startup and shutdown.

12. D-38

Comment: Fabric filters and ESP's which are well operated and maintained can achieve an opacity limit of 1 percent. Accordingly, EPA should adopt an opacity limit of 1 percent.

13. D-37, D-57

Comment: There is no justification of establishing a "not to be exceeded" limitation of opacity of 20 percent. Opacity cannot be correlated to mass emission rates. Opacity limits should only be used as an indicator of possible exceedance for reporting purposes.

14. D-54

Comment: Facilities burning gas and oil should be exempt from the continuous opacity monitoring requirement.

2.7.3 Data Collection

1. D-3, D-23

Comment: The NO_x averages based on 720 hours of operation would not be consistent with data collected for calendar time periods, and will be administratively burdensome. The 30-day averages should be calculated on rolling calendar time periods.

2. D-3

<u>Comment</u>: The data availability requirement in 60.45b(f) is too lenient because it allows a source to be in compliance while collecting less than 0.3 percent valid data (1 hour valid data for every 16 days). A required percent (75 percent is recommended) valid data should be specified for each 30-day period.

3. D-5, D-53

<u>Comment</u>: To be consistent with 40 CFR Part 60 Subpart D, the proposed minimum sampling time (for particulate matter emissions) of 120 minutes, and the minimum sampled volume of 120 dscf, should be lowered to 60 minutes and 60 dscf, respectively.

2.7.4 <u>Reporting Requirements</u>

1. D-3, D-31, D-38

<u>Comment</u>: Submittal of reports on a semiannual basis is too infrequent for tracking CEMS operation, maintenance, and quality assurance data. Reports should be submitted quarterly and include emissions, data validation, and calibration information.

2. D-31

<u>Comment</u>: Affected facilities located in States to which EPA has delegated enforcement authority should not be required to submit reports to EPA. In these cases, the reporting requirements would be duplicative and should be waived.

3. D-31

Comment: It is unclear in 60.46b(h).what specific items should be reported on excessive opacity in order to fulfill the reporting requirement.

4. D-38

Comment: Reports should be required, regardless of whether an excess emission has occurred, in order to ensure that some sources do not neglect to file a report.

2.7.5 Exemptions

1. D-3

Comment: The exemptions allowed in 60.44b(a) would not encourage efforts to minimize emissions during startup, shutdown, and malfunction. Rather than granting a blanket exemption, EPA should specify a percentage of each reporting period when exceedances during startup, shutdown, and malfunction would be allowed.

2. D-5, D-24, D-25, D-36, D-37, D-40, D-47, D-49

Comment: One 6-minute per hour exemption should be allowed for opacity. The 27 percent opacity allowance under 40 CFR Part 60 Subpart D should be extended to the smaller units covered in the proposed regulations.

3. D-13, D-39, D-47, D-57

Comment: The EPA should revise the proposed standard to allow for a number of 6-minute average opacity readings of above 20 percent to account for rapidly changing fuel feed rates or fuel quality.

4. D-29

Comment: The existing provisions for petitioning the Administrator for an exemption from the proposed standards are inadequate. Meeting the NO_x emission limits for some type of units (e.g., THROX) may not result in non-compliance with other Federal, State or local regulations, although it would still result in diminished destruction efficiencies and interference with process operation. The petitioning procedures would cause substantial delay, expense, and uncertainty.

5. D-36, D-43

Comment: An allowance for soot blowing in residual oil- and solid fuel-fired units should be included.

6. D-39

Comment: The provisions for petitioning the Administrator for units burning hazardous wastes should be expanded to allow these units to "maintain the appropriate destruction efficiency."

7. D-37, D-45, D-49, D-53

Comment: Sources equipped with wet scrubbers for particulate matter control should be exempted from the opacity monitoring requirements.

2.7.6 Enforcement/Permitting

1. D-17

Comment: If EPA delegates to a State the authority to enforce the proposed regulations, would a permit which limits the capacity factor have to be adopted as part of the State implementation plan (SIP)?

2. D-54

<u>Comment</u>: The rationale for the "capacity factor basis" appears designed to accommodate those who permit multiple and/or standby fuels. The problem with the Agency's approach is that, while a facility may be permitted to burn residual oil 25 percent of the time, the facility actually burns 100 percent oil during those 90 days per year. This proposal would leave such an operation with permit limits that could be met only by burning 25 percent oil all year long. Thus, this approach does not appear to be appropriate for use with the EPA's proposed 30-day rolling average limits.

2.8 EMISSION CREDITS FOR COMBINED CYCLE SYSTEMS

1. D-16, D-29, D-34, D-36, D-39, D-40, D-44, D-54

<u>Comment</u>: Emission credits should be provided for combined cycle and other cogeneration systems.

2. D-16, D-29, D-40, D-44

<u>Comment</u>: The EPA should defer to State and local agencies in determining on a case-by-case basis specific emission limits to ensure that emission credits do in fact lead to net reductions in emissions.

3. D-34, D-36

<u>Comment</u>: Emission reduction credits are often the difference between making or breaking a cogeneration project.

4. D-36, D-39

Comment: Site-specific factors should not prevent EPA from allowing emission credits for cogeneration systems. A credit equivalent to about 50 percent of the credit that would be given on a one-to-one basis should be allowed.

5. D-36, D-39, D-46

Comment: The EPA's decision not to provide emission credits for cogeneration systems is contrary to Congressional intent in passing PURPA and other energy/environmental legislation.

6. D-44

Comment: Emission credits could be granted on a system-wide basis for an electric utility based on system-wide reductions in emissions achieved by avoidance of new conventional technologies or replacement of older sources.

7. D-39, D-44, D-54

Comment: The EPA has exaggerated the potential for cogeneration systems to displace cleaner sources of energy such as hydroelectric or nuclear facilities.

2.9 ENERGY, ENVIRONMENTAL, AND ECONOMIC IMPACTS

2.9.1 Energy Impacts

1. D-25, D-30, D-48, D-49

Comment: The proposed NO_x standards will not promote energy efficiency. The use of staged combustion (SC) will result in operation of units at unnecessarily high excess air rates.

2. D-29

Comment: The proposed NO_x standards may limit the use of hydrogen and other wastes as fuel and lead to increased usage of natural gas.

3. D-30, D-36

Comment: The proposed NO_x standards will decrease energy efficiency by limiting the use of combustion air preheat.

2.9.2 Environmental Impacts

1. D-25, D-30, D-37, D-47, D-48, D-55, D-57

Comment: The EPA has overestimated the environmental benefits associated with this NSPS. The number of new steam generating units projected is too high and the "baseline" emission levels used by EPA in calculating national impacts are too high.

2. D-30, D-48

Comment: The use of SC will result in many units being out of compliance with State regulations for particulate matter.

3. D-16, D-25, D-29, D-30, D-36, D-37, D-43, D-48, D-49, D-54

Comment: The EPA has not investigated the impacts of higher carbon monoxide, particulate, and hydrogen emissions resulting from use of SC.

4. D-18, D-57

Comment: The EPA estimates of the total emission reductions which would be achieved under the proposed NSPS are only a few tenths of a percent of total national emissions. The EPA has greatly overstated the benefits of the proposed NSPS by not distinguishing steam generating units larger than 73 MW (250 million Btu/hour) heat input capacity from those in the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range.

5. D-18, D-37, D-57

Comment: The EPA should perform a more thorough examination of the impacts of the proposed NSPS versus the benefits achieved under State regulations in order to determine whether the proposed standard will result in a significant improvement in air quality.

6. D-18, D-37, D-55

Comment: The proposed standards may result in delays in replacement of existing steam generating units, resulting in higher emissions. Most new steam generating units are likely to be replacements for older units.

7. D-57

Comment: The tightening of the existing particulate matter emission limit for coal-fired steam generating units would provide no discernible environmental benefit in maintaining the NAAQS.

2.9.3 Economic Impacts

1. D-30, D-48

Comment: By forcing the premature use of SC, the financially depressed steam generating unit/burner market will be subjected to "excessive risk." The steam generating unit/burner market is in no position to shoulder this risk because of recent declines in the market.

2. D-23, D-33

Comment: The proposed regulations for particulate matter emissions could raise the cost of a coal-fired steam generating unit by as much as 10 percent, which would discourage the transition from oil or gas to coal. They may encourage more industries to locate overseas.

3. D-36

Comment: The 15 percent steam generating unit derating required for package residual oil-fired steam generating units to meet the NO_x emission limits would increase the cost of these steam generating units by 10 percent.

4. D-57

Comment: The proposed emission limits for particulate matter would increase capital costs and result in reduced operating flexibility and increased downtime.

2.10 MISCELLANEOUS COMMENTS

1. D-17

Comment: The wording in 60.42b(c) is cumbersome and unclear.

2. D-26

Comment: The phrase "after initial startup" should be deleted from 60.44b(e)(2) in order to eliminate possible confusion with the requirements set forth in 60.8(a).

3. D-38

Comment: In calculating the achievable emission levels for various technologies, EPA appears to have relied on statistical techniques that specify an emission level that will be exceeded only once every 10 years. This implies that enforcement action will result for one exceedance in a 10-year period. The EPA should calculate the achievable emission levels based on one assumed exceedance every year, every 2 years, and every 5 years.

4. D-38

Comment: The EPA has ignored the potentially important emission reductions of both particulate matter and NO_x that could be achieved by the selective use of natural gas and distillate oil. The EPA should examine the emissions, costs, and energy implications of standards for coal- and residual oil-fired steam generating units that assume the proportional use of these cleaner fuels at several alternative levels of use.

5. D-47

Comment: Section 60.43b needs to be clarified. Paragraph (a) entry (6) in the table indicates that mixtures of gas or oil with wood or solid waste have an emission limit of 129 ng/J (0.3 lb/million Btu) heat input. Entry (7) conflicts with this limit. The reference to entry (5) apparently should be to entry (6). Otherwise, the formula in paragraph (b) would have to be used to calculate the NO_x emission limit for gas/oil/wood combinations, and this would be incorrect. Also, there is a problem with the formula in paragraph (b) as it applies to mixtures of wood/coal/gas/oil. A 29 MW (100 million Btu/hour) heat input capacity steam generating unit with a heat input of 5.9 MW (20 million Btu/hour) from wood, 2.9 MW (10 million Btu/hour) from gas, and 21 MW (70 million Btu/hour) from coal would have an emission limit of 275 ng/J (0.64 lb/million Btu) heat input. This problem could be corrected by changing the definition of Ht to include heat input from wood when wood is burned with gas <u>and</u> coal or with oil <u>and</u> coal. The definition of Hu should be modified to include mixtures of distillate oil and wood.

6. D-50

<u>Comment</u>: The equation used for the NO_x limit for mixed fossil/nonfossil fuel burning needs to include a term for the heat input from nonfossil fuels in the denominator.

7. D-57

Comment: The EPA should not propose any new rules governing particulate matter emissions while revisions to the NAAQS for particulates are still being considered.

8. D-30

Comment: 60.43b(d) refers to modification of a facility as defined in §60.15. However, §60.15 covers reconstruction, and §60.14 covers modification. Which is correct?

9. D-30

Comment: In 60.44b(a), the reference should be 60.43b, not 60.42b.

2.11 NO_x EMISSION LIMITS FOR WOOD RESIDUE AND NATURAL GAS-FIRED UNITS

1. D-77, D-78, D-79

Comment: The proposed rule that corrects the NSPS for units firing mixtures of wood residue and natural gas to 129 ng/J (0.30 lb/million Btu) heat input is strongly endorsed.

2. D-77, D-78, D-79

Comment: The correction to the proposed rule should be adopted as soon as possible (before May 31, 1986, D-77).