WEST VIRGINIA
SECRETARY OF STATE
BETTY IRELAND
ADMINISTRATIVE LAW DIVISION

Form #3

Do Not Mark In This Box

RECEIVED

2007 JUL 26 PM 4:35

SECRETARY OF STATE
STATE OF WEST VIRGINIA

NOTICE OF AGENCY APPROVAL OF A PROPOSED RULE AND FILING WITH THE LEGISLATIVE RULE-MAKING REVIEW COMMITTEE

AGENCY: West Virginia Department of Environmental Protection - Division of Air Quality TITLE NUMBER: 45

CITE AUTHORITY: WV Code §22-5-4

AMENDMENT TO AN EXISTING RULE: YES X NO ___

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 16

TITLE OF RULE BEING AMENDED: Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60

IF NO, SERIES NUMBER OF RULE BEING PROPOSED: ___

TITLE OF RULE BEING PROPOSED: ___

THE ABOVE PROPOSED LEGISLATIVE RULE HAVING GONE TO A PUBLIC HEARING OR A PUBLIC COMMENT PERIOD IS HEREBY APPROVED BY THE PROMULGATING AGENCY FOR FILING WITH THE SECRETARY OF STATE AND THE LEGISLATIVE RULE-MAKING REVIEW COMMITTEE FOR THEIR REVIEW.

Authorized Signature

WEST VIRGINIA
SECRETARY OF STATE
Betty Ireland
ADMINISTRATIVE LAW DIVISION

Form #1

Do Not Mark In This Box

FILED

2007 JUN -6 PM 4:25

OFFICE OF WEST VIRGINIA
SECRETARY OF STATE

NOTICE OF A PUBLIC HEARING ON A PROPOSED RULE

AGENCY: WV Department of Environmental Protection - Division of Air Quality TITLE NUMBER: 45

RULE TYPE: Legislative CITE AUTHORITY: WV Code §22-5-4

AMENDMENT TO AN EXISTING RULE: YES [X] NO [ ]

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 16

TITLE OF RULE BEING AMENDED: Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60

IF NO, SERIES NUMBER OF RULE BEING PROPOSED: _____

TITLE OF RULE BEING PROPOSED: _____

DATE OF PUBLIC HEARING: July 9, 2007 TIME: 6:00 p.m.

LOCATION OF PUBLIC HEARING: West Virginia Department of Environmental Protection
Dolly Sods Conference Room
601 57th Street, SE
Charleston, WV 25304

COMMENTS LIMITED TO: ORAL [ ] WRITTEN [ ] BOTH [X]

DATE WRITTEN COMMENT PERIOD ENDS: July 9, 2007 TIME: 6:00 p.m.

WRITTEN COMMENTS MAY BE MAILED TO:
Public Information Office
Department of Environmental Protection
601 57th Street, SE
Charleston, WV 25304

The Department requests that persons wishing to make comments at the hearing make an effort to submit written comments in order to facilitate the review of these comments.

Legislative Rule-Making

The issues to be heard shall be limited to the proposed rule.

ATTACH A **BRIEF** SUMMARY OF YOUR PROPOSAL

JUN - 6 2007

Authorized Signature

Review Committee

QUESTIONNAIRE

(Please include a copy of this form with each filing of your rule: Notice of Public Hearing or Comment Period; Proposed Rule, and if needed, Emergency and Modified Rule.)

DATE: July 26, 2007

TO: LEGISLATIVE RULE-MAKING REVIEW COMMITTEE

FROM: (*Agency Name, Address & Phone No.*) WV Department of Environmental Protection
Division of Air Quality
601 57th Street, S.E.
Charleston, West Virginia 25304
Phone: 304-926-0499 ext. 1237

LEGISLATIVE RULE TITLE: 45CSR16 - Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60

1. Authorizing statute(s) citation W.Va. Code §22-5-4

2. a. Date filed in State Register with Notice of Hearing or Public Comment Period:

June 6, 2007

b. What other notice, including advertising, did you give of the hearing?

Published notice on June 9th in The Charleston Daily Mail and The Charleston Gazette. Posted on the Department of Environmental Protection's web site under "Calendar of Events".

c. Date of Public Hearing(s) ***or*** Public Comment Period ended:

July 9, 2007

d. Attach list of persons who appeared at hearing, comments received, amendments, reasons for amendments.

Attached _____ No comments received X

e. Date you filed in State Register the agency approved proposed Legislative Rule following public hearing: (be exact)

July 26, 2007

f. **Name, title, address and phone/fax/e-mail numbers** of agency person(s) to receive all *written correspondence* regarding this rule: (Please type)

John A. Benedict, Director
601 57th Street, S.E.
Charleston, WV 25304

Phone: 304 926-0499
Fax: 304 926-0488
e-mail: jbenedict@wvdep.org

Tamra Mowrer, Administrative Secretary
601 57th Street, S.E.
Charleston, WV 25304

Phone: 304 926-0499
Fax: 304 926-0488
e-mail: tmowrer@wvdep.org

g. **IF DIFFERENT FROM ITEM 'f'**, please give **Name, title, address and phone number(s)** of agency person(s) who wrote and/or has responsibility for the contents of this rule: (Please type)

James Mason, Technical Analyst II
601 57th Street, S.E.
Charleston, WV 25304

Phone: 304 926-0499 ext. 1200
Fax: 304 926-0479

3. If the statute under which you promulgated the submitted rules requires certain findings and determinations to be made as a condition precedent to their promulgation:

a. Give the date upon which you filed in the State Register a notice of the time and place of a hearing for the taking of evidence and a general description of the issues to be decided.

N/A

b. Date of hearing or comment period:

N/A

c. On what date did you file in the State Register the findings and determinations required together with the reasons therefor?

N/A

d. Attach findings and determinations and reasons:

Attached N/A

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY

BRIEFING DOCUMENT

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

A. AUTHORITY: W.Va. Code §22-5-4.

B. SUMMARY OF RULE:

This rule establishes and adopts national standards of performance for new stationary sources and other regulatory requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement standards of performance for new stationary sources set forth in 40 CFR Part 60. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to such standards. Any person who constructs, modifies, reconstructs or operates an affected facility after the effective date of any NSPS under 40 CFR Part 60 must comply with the applicable NSPS and this rule.

This revised rule incorporates by reference the following new or revised NSPS standards promulgated as of June 1, 2007: Standards of Performance for: New and Existing Stationary Sources - Electric Utility Steam Generating Units; Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978, Industrial- Commercial- Institutional Steam Generating Units, Small Industrial- Commercial- Institutional Steam Generating Units; Stationary Gas Turbines and Monitoring Requirements; Stationary Compression Ignition Internal Combustion Engines; and Methods for Measurement of Visible Emissions.

C. STATEMENT OF CIRCUMSTANCES WHICH REQUIRE RULE:

As set forth in 40 CFR §60.4(b), Section 111(c) of the CAA directs the U.S. EPA Administrator to delegate to each State the authority to implement and enforce standards of performance for new stationary sources. Promulgation of this rule will enable the State to continue to be the primary enforcement authority for the NSPS promulgated by U.S. EPA. Revisions to this rule are necessary to maintain consistency with current federal regulations, and to fulfill the State's responsibilities under the CAA. Revisions to the rule include revised title, annual incorporation by reference updates, updated exclusions to 40 CFR Part 60 incorporation by reference, and general language clarification and correction.

D. FEDERAL COUNTERPART REGULATIONS - INCORPORATION BY REFERENCE/DETERMINATION OF STRINGENCY:

A federal counterpart to this proposed rule exists. In accordance with the Secretary's recommendation, and with limited exception, the Division of Air Quality proposes that the rule incorporate by reference the federal counterparts. Because the proposed rule incorporates by reference the federal counterpart, no determination of stringency is required.

E. CONSTITUTIONAL TAKINGS DETERMINATION:

In accordance with W.Va. Code §§22-1A-1 and 3(c), the Secretary has determined that this rule will not result in taking of private property within the meaning of the Constitutions of West Virginia and the United States of America.

F. CONSULTATION WITH THE ENVIRONMENTAL PROTECTION ADVISORY COUNCIL:

At its May 21, 2007, and May 30, 2007 meetings, the Environmental Protection Advisory Council reviewed and discussed this rule. (See attached minutes for Council's discussion).

West Virginia Department of Environmental Protection

ADVISORY COUNCIL MEETING MINUTES

Monday – May 21, 2007
1:00 p.m. – 3:00 p.m.
601 57th Street, SE, Charleston, WV
West Virginia Room – 3rd Floor

ATTENDEES:

Advisory Council Members:

Rick Roberts
Karen Price
Bill Raney
Lisa Dooley
Larry Harris
Jackie Hallinan

DEP:

Randy Huffman, Deputy Cabinet Secretary/Director –Division of Mining & Reclamation
Karen G. Watson, Assistant General Counsel
Ken Ellison, Director - Division of Land Restoration
Lisa McClung, Director – Division of Water and Waste Management
John Benedict, Director – Division of Air Quality
Lewis Halstead, DMR
Ken Politan, DMR
Charlie Sturey, DMR
Jessica Greathouse, Chief Communication Officer – WVDEP – Public Information Office
James Martin, Chief, Office of Oil & Gas
Carroll Cather, DWWM
Pam Nixon, Advocate
David L. Vande Linde, Blasting
Jim Mason, DAQ
Mike Zeto, DWWM – EE
Matt Sweeney, DWWM

VISITORS:

Ann Bradley, Spilman Thomas & Battle
Charlie Burd, IOGA
Don Garvin, WVEC
Dave Yaussy, Robinson & McElwee

Randy Huffman, Deputy Cabinet Secretary - West Virginia Department of Environmental Protection called the meeting to order at 1:00 p.m.

Karen Price stated that the Council did not have enough time to review the rules, therefore was requesting to have another meeting to discuss further and the remaining of the Council agreed. The Council will meet May 30, 2007 at 10:00 a.m. – WVDEP – 601 57th Street, SE – Charleston, WV 25304 – West Virginia Room (3001).

Deputy Cabinet Secretary Huffman apologized for the short time period regarding the rules getting out to Council. Randy Huffman then introduced Karen Watson, Assistant General Counsel to discuss with the Council the DEP bills that had passed in the 2007 Regular Legislative Session:

- SB 337 – Establishing New Greenhouse Gas Inventory Program
  Approved by Governor – April 4, 2007

- SB 425 – Relating to Water Pollution Control Revolving Fund
  Approved by Governor – April 4, 2007

- SB 465 – Establishing Dam Safety Rehabilitation Revolving Fund
  Approved by Governor – March 27, 2007

- SB 490 – Relating to Underground Storage Tank Insurance Fund
  Approved by Governor – April 3, 2007

- SB 524 – Requiring Proof of Lawful Disposal of Solid Waste
  Approved by Governor – March 28, 2007

- SB 588 – Removing Tax Expiration Date on Manufacturing or Production of Synthetic Fuel From Coal
  Approved by Governor – April 4, 2007

Karen Watson then gave a brief summary of each proposed rule for the 2008 legislative session:

Air Quality

45CSR6 – Control of Air Pollution from Combustion of Refuse

SUMMARY

Proposed Rule 6 is now a basic open burning/ incinerator rule. Revised scope includes 'statutory air pollution,' addition of new language for posted operating instructions and open burning or incineration of animal or poultry carcasses during a declared state of emergency. Except for temporary Air Curtain Incinerators for land clearing debris (DOH jobs) and incineration of animal or poultry remains, most Air Curtain Incinerators will now be exempted under Rule 6 and placed under Rule 18.

COMMENT

Mr. Harris: Why does it allow low-level radioactive waste?

DEP Response: To allow crematories to dispose of bodies with chemo drugs. Does not allow high-level radioactive compounds related to research.

~~Council wanted to know if the agency would accept comments in writing after the meeting (e-mail in~~ comments)

DEP Response: Yes

45CSR8 – Ambient Air Quality Standards

SUMMARY

NAAQS rules 45CSR8, 45CSR9 & 45CSR12 have been combined for the 2008 legislative session. Rule 8 is now the complete NAAQS incorporation by reference rule, and 45CSR9 & 45CSR12 will be repealed and replaced. Revisions to SO_2 & PM NAAQS include correction of SO_2 annual primary standard from 0.003 to 0.030 ppm, addition of annual and 24-hour $PM_{2.5}$ standards, and addition of measurement methods for $PM_{2.5}$. Revisions to CO & Ozone NAAQS include revocation of one-hour ozone standard except for Berkeley & Jefferson counties, identification of one-hour ozone maintenance areas, and addition of 8-hour primary and secondary ozone standards. Revisions to NO_2 and Lead NAAQS include addition of primary and secondary standards for lead, and addition of measurement methods for lead. Revisions also include general language updates, improved citing and consistency.

COMMENT

Mr. Harris: Are we sure we are protecting the public's health? We should not be lowering standards so that our energy being transmitted to other states doesn't pollute our air. Are we aware of EPA's Science Advisory Panel?

DEP Response: CAIR aims to lower emissions at power plants. Utility controls are helping us meet targets earlier. EPA's regional approach has generally been successful and we are seeing tremendous benefits. The agency is aware of the EPA's panel, and EPA is considering more stringent regulations but has not done so yet.

45CSR16 – Standards of Performance for New Stationary Sources

SUMMARY

Revisions to rule incorporate annual incorporation by reference updates and exclusions.

COMMENT

No questions.

45CSR18 – Control of Air Pollution from Combustion of Solid Waste

SUMMARY

CISWI Rule 18 combines and incorporates by reference all current federal Section 111/129 combustion regulation into one rule. Old Rule 24 will be repealed and replaced. New exemption section is consistent with revised Rules 6, 25 and 34. Revisions also include revised scope, extensive federal counterpart language updates, improved citing and consistency.

COMMENT

No questions.

45CSR25 – Control of Air Pollution from Hazardous Waste Treatment, Storage and Disposal Facilities

SUMMARY

Revisions to the proposed rule include general annual incorporation by reference and revisions required to maintain consistency with the DWWM's rule 33CSR20 and federal counterpart regulation. Addition of direct incorporation by reference of new provisions published in the Federal Register. Language for pathological waste incinerators is revised for clarity.

COMMENT

No questions.

45CSR34 – Emission Standards for Hazardous Air Pollutants

SUMMARY

Rule 34 now combines all NESHAP regulations previously adopted under both Rules 15 & 34. Old Rule 15 will be repealed and replaced. Revisions to Rule 34 incorporate annual NESHAP updates under Parts 61 & 63. Some Part 63 standards affecting non-major sources of hazardous air pollutants are being excluded from incorporation by reference: Oil and Natural Gas; Polyvinyl Chloride and Copolymers; Primary Copper Smelting; Secondary Copper Smelting; and Primary Nonferrous Metals.

COMMENT

No questions.

45CSR39 – Control of Annual Nitrogen Oxides Emissions

SUMMARY

Annual CAIR NOx Rule - Incorporates revisions to 40 CFR Part 96.

COMMENT

No questions.

45CSR40 - Control of Ozone Season Nitrogen Oxides Emissions

SUMMARY

Ozone Season CAIR NOx Rule - Incorporates revisions 40 CFR to Part 96.

COMMENT

No questions.

45CSR41 – Control of Annual Sulfur Dioxide Emissions

SUMMARY

Annual CAIR SO_2 Rule - Incorporates revisions to 40 CFR Part 96.

COMMENT

No questions.

45CSR42 – Greenhouse Gas Emissions Inventory Program

SUMMARY

The Greenhouse Gas Inventory Program Rule is authorized by SB337 passed in the 2007 legislative session. The rule establishes a program which requires the reporting and inventory of greenhouse gas emissions by stationary sources which emit more than a *de minimis* amount; inventories greenhouse gas emissions from stationary, area, mobile and biogenic sources, and accounts for reductions, capture and sequestration; provides for: a periodic compilation of a greenhouse gas inventory; a determination whether WV is a net sink or emitter; development of a registry for voluntary reductions; and a determination whether greenhouse gas can be developed as an asset for economic development.

COMMENT

Mr. Raney: Is the exclusion still there for coal preparation activities?

DEP Response: Yes, section 3.2. (45CSR42)

Mr. Raney: How do we quantify sequestration?

DEP Response: Don't think we will get down to stationary source level. Agency will look at area

sources and biogenic activities. Once we get information, we will compile in an inventory.

Division of Water and Waste Management

33CSR9 – Standards for Beneficial use of Filtrate from Water Treatment Plants

SUMMARY

This legislative rule establishes a mechanism and requirements for the permitting, siting, bonding, and use of water treatment plant sludge from water treatment plants that has beneficial properties. This rule applies to the beneficial use of water treatment plant sludge and to any person who seeks approval from the Secretary to beneficially use such sludge within the state. This rule is intended to enhance the resource recovery and recycling goals of article fifteen of chapter twenty-two of the West Virginia Code and to encourage the beneficial use of water treatment plant filtrate. Section 22-15-23 of the West Virginia Code and this rule, and not the provisions of W. Va. Code § 22-15-10 or 33 CSR 1, shall govern the beneficial use of water treatment plant sludge. This rule does not apply to sewage sludge, products derived from sewage sludge, sludges regulated under 33 CSR 8, or materials regulated as hazardous waste under W. Va. Code §§22-18-1, et seq.

COMMENT

Lisa Dooley: Public notice of permits – who bears the cost – there has to be a more efficient way of getting notices out than Class I legal ads. This is a suggestion for the future.

DEP Response: Applicant bears cost – DEP is trying other methods of getting the information out – but not everyone has access to e-mail.

400 people on DEP's mailing list to receive permits by e-mail and we have between 30-40 who receive permits by US mail.

33CSR20 – Hazardous Waste Management System

SUMMARY

This amendment will adopt by reference approximately two years of changes to federal regulations by adopting the federal regulations in effect as of June 1, 2007 consisting of changes that correct errors in previously enacted Dye and Pigment rule and Manifest rule, allow more hazardous waste, allow greater flexibility in SW-846 testing and monitoring, allow more mercury containing devices to be managed as universal waste, streamline permitting process through a standardized permit, allow additional headworks and de minimus waste exemptions, reference Clean Air Act standards for hazardous waste combustors, allow a series of paperwork burden reductions for hazardous waste management facilities, corrects errors in 40 CFR (federal regulations) and excludes cathode ray tubes from the definition of solid waste under certain conditions. Language corrections, updated references and a change as the result of an EPA comment regarding annual groundwater monitoring at corrective action sites are also included in the amended rule. The rule amendment is not projected to require additional operating expenses above current levels as the amendments are generally de-regulatory in nature.

COMMENT

No questions.

33CSR30 – Underground Storage Tanks

SUMMARY

There are several new provisions to reflect the 2005 Federal Energy Act, including: secondary containment requirements for new or replaced thanks or piping; secondary containment requirements for new or replaced fuel dispenser systems; tank eligibility for delivery, deposit or acceptance – enables agency to prevent deposit or delivery to a tank that is not in compliance; and training requirements for individuals who operate, maintain or are responsible to address emergencies from spills or releases from underground storage tank systems.

COMMENT

No questions.

47CSR2 – Requirements Governing Water Quality Standards

SUMMARY

The proposed revisions reflect updates identified during the federally-mandated triennial review of the Water Quality Standards rule. These include proposed additions to the trout water list, new criteria for nutrients, revisions to criteria in Appendix E and a use redesignation in the Guyandotte River Basin.

COMMENT

Mr. Raney: Would like to have the trout water list stay within the agency and be able to discuss the science on a case-by-base basis before the EQB, not the Legislature.

DEP Response: The DEP believes the scientific basis for the proposed trout streams is clear and does not need to be litigated before the EQB.

Mr. Harris: Commented on the changes in Appendix E and asked whether the formula change for copper and cadmium resulted in a more or less stringent standard.

DEP Response: The changes in Appendix E are recommended by EPA, updating MCL's, etc. The revised hardness formulas represent EPA's latest science.

47CSR10 – National Pollutant Discharge Elimination System (NPDES)

SUMMARY

The proposed revisions to the National Pollutant Discharge Elimination System Rule reflect updates/additions made to the various federal regulations that govern the NPDES program. The proposed changes also include specific language in section 14 of the rule relating to the Pretreatment Program to ensure that the rule is consistent with the most recent federal pretreatment regulations in 40 CFR Part 403.

COMMENT

No questions.

47CSR34 – Dam Safety

SUMMARY

The proposed revisions establish requirements governing the disbursement and use of moneys in the Dam Safety Rehabilitation Revolving Fund, authorized by SB 465 in the 2007 legislative session.

COMMENT

Ms. Hallinan: Any progress being made in reducing the number of deficient dams?

DEP Response: Not very much. The fund initiative is badly needed.

60CSR5 – Antidegradation Implementation Procedures

SUMMARY

Antidegradation is a requirement of the federal Clean Water Act intended to preserve the existing quality of the State's waters and to prevent and/or minimize future degradation. The rule was first adopted in 2001 and establishes four levels, or tiers, of protection for state waters, Tiers 1, 2, 2.5 and 3. Each tier provides a graduated level of protection used during the NPDES permit issuance process. The proposed revisions to the rule carry forward the agency's antidegradation implementation efforts, and move the Tier 2.5 streams that had been on the "presumptive" list in Appendix C to a final proposed list in Appendix A. The agency is proposing a total of 156 streams be included on the list. The list of 156 waters is comprised of the 37 waters that did not receive objections in the formal objection period, those waters that contain reproducing trout and are 100% on public land, those waters listed as high quality on public land based on their high biological scores, and Loop Creek.

COMMENT

Mr. Harris: Suggested we file with 309 streams instead of 156 streams because Legislature will further reduce.

Jackie Hallinan: The program is a good idea.

Meeting was adjourned by Deputy Cabinet Secretary Randy Huffman.

West Virginia Department of Environmental Protection

ADVISORY COUNCIL MEETING MINUTES

Wednesday – May 30, 2007
10:00 a.m. – 12:00 p.m.
601 57th Street, SE, Charleston, WV
West Virginia Room – 3rd Floor

ATTENDEES:

Advisory Council Members:

Rick Roberts
Karen Price
Bill Raney
Larry Harris - Teleconference
Jackie Hallinan

DEP:

Randy Huffman, Deputy Cabinet Secretary/Director –Division of Mining & Reclamation
Karen G. Watson, Assistant General Counsel
Lisa McClung, Director – Division of Water and Waste Management
John Benedict, Director – Division of Air Quality
Jessica Greathouse, Chief Communication Officer – WVDEP – Public Information Office
Pam Nixon, Advocate
Jim Mason, DAQ
Mike Zeto, DWWM – EE
John Morgan, DWWM
Scott Mandirola, DWWM
Greg Adolfson, PIO

VISITORS:

Dave Yaussy
Brittany Carns
Joe Gollehon
Gregory Hoyer
Jeff Mauzy
Amy Christy

Randy Huffman, Deputy Cabinet Secretary - West Virginia Department of Environmental Protection called the meeting to order at 10:00 a.m. Advisory Council Member Larry Harris joined the meeting via teleconference. Deputy Cabinet Secretary Huffman then turned the meeting over to Karen Watson, Assistant General Counsel for the West Virginia Department of Environmental Protection. Karen informed the Council that the agency had received comments from several Council members and those comments would be appended to the minutes. (see attached) She explained the agency

had representatives from each of the programs to answer questions for the rules identified in those comments. She also explained the agency had made several changes in the rules as a result of those comments.

Air Quality

45CSR6 – Control of Air Pollution from Combustion of Refuse

SUMMARY

Proposed Rule 6 is now a basic open burning/ incinerator rule. Revised scope includes 'statutory air pollution,' addition of new language for posted operating instructions and open burning or incineration of animal or poultry carcasses during a declared state of emergency. Except for temporary Air Curtain Incinerators for land clearing debris (DOH jobs) and incineration of animal or poultry remains, most Air Curtain Incinerators will now be exempted under Rule 6 and placed under Rule 18.

COMMENT

Larry Harris: Had raised the issue of "low-level radioactive waste" in the last meeting.

DEP Response: DEP has removed the chemotherapeutic waste and low-level radioactive waste provisions from the proposed rule. The proposed rule does not in any way affect current medical waste incineration rules now on the books.

45CSR8 – Ambient Air Quality Standards

SUMMARY

NAAQS rules 45CSR8, 45CSR9 & 45CSR12 have been combined for the 2008 legislative session. Rule 8 is now the complete NAAQS incorporation by reference rule, and 45CSR9 & 45CSR12 will be repealed and replaced. Revisions to SO_2 & PM NAAQS include correction of SO_2 annual primary standard from 0.003 to 0.030 ppm, addition of annual and 24-hour $PM_{2.5}$ standards, and addition of measurement methods for $PM_{2.5}$. Revisions to CO & Ozone NAAQS include revocation of one-hour ozone standard except for Berkeley & Jefferson counties, identification of one-hour ozone maintenance areas, and addition of 8-hour primary and secondary ozone standards. Revisions to NO_2 and Lead NAAQS include addition of primary and secondary standards for lead, and addition of measurement methods for lead. Revisions also include general language updates, improved citing and consistency.

COMMENT

Karen Price: Section 4.2.c – $PM_{2.5}$ Maximum 24-Hour Average Concentration. The level for the 24-hour primary and secondary standard states 35 ug/m^3. This should be 65 ug/m^3, pursuant to 40 CFR 50.7.

DEP Response: On October 17, 2006, the federal NAAQS regulation changed from 65 to 35.

Larry Harris: Restated his concern that the standards may not be stringent enough to protect public health. He also restated his question about the antidegradation language struck from the rule.

DEP Response: DEP cannot lower the NAAQS standards below that of federal levels unless the provisions for the stringency test in §22-1-3a are fully met. 45CSR14, in its entirety, has wholly replaced the intent of the relic anti-degradation language struck in proposed Rule 8.

45CSR39 – Control of Annual Nitrogen Oxides Emissions

45CSR40 - Control of Ozone Season Nitrogen Oxides Emissions

Ozone Season CAIR NOx Rule - Incorporates revisions 40 CFR to Part 96.

Annual CAIR NOx Rule - Incorporates revisions to 40 CFR Part 96.

45CSR41 – Control of Annual Sulfur Dioxide Emissions

Annual CAIR SO_2 Rule - Incorporates revisions to 40 CFR Part 96.

COMMENT

Karen Price: Asked why the opt-in language was deleted from each of these rules.

DEP Response: has removed the opt-in provisions in the three CAIR rules so that West Virginia can say that CAIR equals NOx RACT for EGUs under the PM2.5 implementation rule.

45CSR42 – Greenhouse Gas Emissions Inventory Program

SUMMARY

The Greenhouse Gas Inventory Program Rule is authorized by SB337 passed in the 2007 legislative session. The rule establishes a program which requires the reporting and inventory of greenhouse gas emissions by stationary sources which emit more than a *de minimis* amount; inventories greenhouse gas emissions from stationary, area, mobile and biogenic sources, and accounts for reductions, capture and sequestration; provides for: a periodic compilation of a greenhouse gas inventory; a determination whether WV is a net sink or emitter; development of a registry for voluntary reductions; and a determination whether greenhouse gas can be developed as an asset for economic development.

COMMENT

Karen Price and Larry Harris: Both asked about the definitions of "anthropogenic" and "biogenic" in the rule and asked for examples of each.

DEP Response: An example of an anthropogenic source is the coal extraction process and an example of a biogenic source is the erosion of soil exposing a coal seam. The agency does not plan

to ask sources to report biogenic activities. In order to receive credit a source must report all of its emissions.

Karen Price: Can the reporting requirement in section 4.1 be made consistent with the emissions inventory requirements.

DEP Response: The date in the rule is March 31st and is the same as the emissions inventory date.

Karen Price: Does not believe fees should be required for greenhouse gas reporting.

DEP Response: The agency will consider the issue.

Karen Price: The last sentence in section 5.3 allowing the Secretary to request information is not authorized by statute.

DEP Response: It is authorized by the statute.

Karen Price: There should be a reasonable protocol for reporting emissions.

DEP Response: D AQ purposely wrote the rule in a manner flexible to the Secretary, as greenhouse gas reduction quantification protocols are still being developed at this time.

Karen Price: Is WV going to sign on to the climate registry or are we going to have our own?

DEP Response: In order to trade, we have to be consistent with other programs, but we do not want to be more specific in the rule.

Bill Raney: The exemption in section 3.2 includes language referring to sources covered by chapter 22-3 as well as sources required to report emissions. We are concerned this may take the exemption in the statute away.

DEP Response: While the agency did not want to require mining extraction to report emissions, thermal dryers associated with coal prep plants often have huge emissions of greenhouse gases. That is the reason the statute and rule only exempt sources permitted under chapter 22-3.

Division of Water and Waste Management

33CSR9 – Standards for Beneficial use of Filtrate from Water Treatment Plants

SUMMARY

This legislative rule establishes a mechanism and requirements for the permitting, siting, bonding, and use of water treatment plant sludge from water treatment plants that has beneficial properties. This rule applies to the beneficial use of water treatment plant sludge and to any person who seeks approval from the Secretary to beneficially use such sludge within the state. This rule is intended to enhance the resource recovery and recycling goals of article fifteen of chapter twenty-two of the West Virginia Code and to encourage the beneficial use of water treatment plant filtrate. Section 22-

15-23 of the West Virginia Code and this rule, and not the provisions of W. Va. Code § 22-15-10 or 33 CSR 1, shall govern the beneficial use of water treatment plant sludge. This rule does not apply to sewage sludge, products derived from sewage sludge, sludges regulated under 33 CSR 8, or materials regulated as hazardous waste under W. Va. Code §§22-18-1, et seq.

COMMENT

Larry Harris: DEP made changes to this rule during the Interims process last year, and the rule now requires a permit for both short-term and long-term applications. This is a good change. However, we feel that most of the information required in Section 7.3. Permit Application Requirements for long-term permits should also be required for short-term permits.

DEP Response: The requirements of section 7.3 were intended to be directed toward facilities that proposed to land apply filtrate as the beneficial use. It was intended to be applicable to both, if land application was the proposed method of reuse. Section 7.3 will be revised to more clearly reflect the applicability of the requirement for both long-term and short-term, if land application is the proposed beneficial reuse.

Rick Roberts and Larry Harris: Regarding the environmental effects of disposal of sludge are the values in Table 1 of the rule sufficient?

DEP Response: The Table 1 values are the same as the sewage sludge levels in DEP's other rules, and the agency believes they are supported by sound science.

Rick Roberts and Larry Harris: Mr. Harris expressed concern with the distinction between "beneficial reuse" and "disposal." Mr. Roberts believes that his concern is satisfied by the language in section 3.1.b.1.

Rick Roberts: The rule should include general permits as proposed.

Larry Harris: Only individual permits should be allowed under the rule.

DEP Response: There will be public notice in the general permit process.

33CSR30 – Underground Storage Tanks

SUMMARY

There are several new provisions to reflect the 2005 Federal Energy Act, including: secondary containment requirements for new or replaced thanks or piping; secondary containment requirements for new or replaced fuel dispenser systems; tank eligibility for delivery, deposit or acceptance – enables agency to prevent deposit or delivery to a tank that is not in compliance; and training requirements for individuals who operate, maintain or are responsible to address emergencies from spills or releases from underground storage tank systems.

COMMENT

Karen Price: Section 6.1. states "....including any person who accepts a delivery order, accepts payment, delivers or deposits product into an underground storage tank.....". The portion that states "...accepts payment..." should be removed from this section because those individuals within a company who accept payment or make payments most often do not know anything about the underground storage tank (UST), the operation of the UST, or the current regulatory status of the UST.

DEP Response: This language will give the agency a better handle on transporters and middle-men involved in the process.

Karen Price: Section 7.3.a.1. states "....the methodology for verifying attendance, the date, time and location of the course, the name of the offering organization, the credentials of the instructors, and a certification that the technology or methods.....".

1. The portion that states "..the date, time and location of the course,...." should be deleted. For large companies with many UST installations and locations there can be numerous individuals that need to be trained. Training will most likely occur on multiple dates, times, and locations that may not always be known until just prior to the training event. When new employees are hired training might occur on short notice and for one individual. The burden of having to report the dates, time and locations would hinder and slow down the training process and restrict a company's ability to comply.

2. The portion that states "...the credentials of the instructors..." should be removed. Credentials will vary from instructor to instructor new instructors might be utilized, and a company might not know which instructors will be used at the various training sessions until just prior to the training session. In addition, the course content is the main issue of concern and should be the main focus in obtaining State approval of a training program.

DEP Response: Regarding dates, times and location of the training the agency will not require the information prior to the training. As far as the credentials of the instructor the agency needs this information as part of its curriculum review, in this case before the training.

Karen Price: Section 7.3.a.2 - This section states that a nonrefundable application fee of $280 must be submitted with the application. Larger companies may have one training program, but administer the training on multiple dates, times and locations. Having to submit an application for approval of the training program each time the program is administered would be cost prohibitive, burdensome, and would hinder the training process.

DEP Response: The agency agrees and believes the rule only requires a one-time fee.

Rick Roberts: Regarding the $5.00 per ton fee, how does a source measure the tonnage? Perhaps the agency should consider using a cubic-yard approach.

DEP Response: The agency will consider.

47CSR2 – Requirements Governing Water Quality Standards

SUMMARY

The proposed revisions reflect updates identified during the federally-mandated triennial review of the Water Quality Standards rule. These include proposed additions to the trout water list, new criteria for nutrients, revisions to criteria in Appendix E and a use redesignation in the Guyandotte River Basin.

COMMENT

Larry Harris: Does the use removal in section 7.2.d follow the federal Clean Water Act requirements?

DEP Response: Yes, the agency followed all the requirements, federal and state, and required extensive information from the company. The agency also conducted two public meetings.
Bill Raney: Mr. Raney repeated his concern with the listing of trout waters in the rule and the fact that the list has to be approved by the Legislature. Karen Price agreed with this comment. Jackie Hallinan and Larry Harris did not agree with this comment.

Karen Price: Questioned the need for Appendix D, because the Category C use applies to all state waters.

DEP Response: Agency will consider.

Karen Price: Will the agency consider not making use removals go through the legislative process.

DEP Response: The agency decided not to include any language pertaining to this issue at this point in time, but will be subjecting this issue to the public participation process in the coming months.

60CSR5 – Antidegradation Implementation Procedures

SUMMARY

Antidegradation is a requirement of the federal Clean Water Act intended to preserve the existing quality of the State's waters and to prevent and/or minimize future degradation. The rule was first adopted in 2001 and establishes four levels, or tiers, of protection for state waters, Tiers 1, 2, 2.5 and 3. Each tier provides a graduated level of protection used during the NPDES permit issuance process. The proposed revisions to the rule carry forward the agency's antidegradation implementation efforts, and move the Tier 2.5 streams that had been on the "presumptive" list in Appendix C to a final proposed list in Appendix A. The agency is proposing a total of 156 streams be included on the list. The list of 156 waters is comprised of the 37 waters that did not receive objections in the formal objection period, those waters that contain reproducing trout and are 100% on public land, those waters listed as high quality on public land based on their high biological scores, and Loop Creek.

COMMENT

Larry Harris: Scientific criteria should be used to add or delete streams from the Tier 2.5 list.

Rick Roberts: Can the SRF program give priority to facilities impacted by the Tier 2.5 list?

DEP Response: Agency will take this under advisement.

Larry Harris: Is the nomination process adequate?

DEP Response: The agency believes the process is generally adequate and workable. If, however a large number of streams are nominated at one time, the individual notification requirements may be difficult and costly.

At this point in the meeting, Bill Raney submitted written comments regarding several mining rules. (see attached)

60CSR8 - Environmental Excellence Program

Greg Adolfson summarized the rule revisions. He said the changes would provide more flexibility for the agency to approve or disapprove of incentives in the program, as well as other flexibilities.

SUMMARY

Changes are being proposed to the Environmental Excellence Program Rule (60CSR8) to better align with and follow the momentum of the United States Environmental Protection Agency's National Environmental Performance Track Program. Additionally, the primary purpose for the changes is to give more flexibility to the Department of Environmental Protection Cabinet Secretary in areas such as: Eligibility Criteria for Participation (section 4); Environmental Performance Record (section 5); Environmental Management System (section 6); Public Participation (section 8); Incentives (section 9); Procedures for Application (section 10); and Annual Performance Report (section 14). Language, such as "may include, but will not be limited to, the following," has been added to allow for this flexibility.

COMMENT

Rick Roberts: Why is section 6.2 completely deleted?

DEP Response: The section is not completed deleted, just the 1996 standards. This will allow the agency to use the most current standards.

Bill Raney: How many companies are participating in the program?

DEP Response: There are two in the National Program, Toyota and Dow.

Mr. Raney: Suggested we start with 39.

Mr. Harris: Asked about section 2.11 in the definitions regarding "trading" and if it includes cross-pollutant trading.

DEP Response: The definitions were unchanged from the ones the EQB first adopted in 2001. The agency does not think it allows cross-pollutant trading.

Division of Mining and Reclamation

38CSR2 – Surface Mining Reclamation Rule

SUMMARY

§38-2-3.2.g. Notice of Technical Completeness is new language and is to provide the public an opportunity to review the application once technical review is completed. §38-2-5.4.e.1 is removing language that is contrary to returning the natural drainway to its original pattern, profile, and dimensions once drainage control structure is removed. The changes in §38-2-5.6 clarify what operations may be exempt from conducting a "Surface Water Runoff Analysis", monitoring requirements and removes phase-in compliance schedule that expired on June 19, 2006. Changes to §38-2-6 removes duplication of rules for Blasting and after this change, all the requirements for blasting will be contained in Surface Mining Blasting Rule, Title 199 Series 1. New §38-2-11.8 titled "Bond Credit for Reclamation of Bond Forfeiture Site under a No Cost Reclamation Contract" encourages qualified operators to undertake reclamation of bond forfeiture sites for the purpose of eliminating hazards to human health and safety, abating pollution of surface and ground waters and the contribution of sediment to adjacent areas, and restoring land to beneficial uses. Changes in §38-2-14.15.c.2 and 14.15.d.3 are clarifying contemporaneous reclamation rules on excess spoil disposal. The changes in 14.15.e remove a phase-in compliance schedule that expired in 2004. The changes in §38-2-23 are being made to make the mining rule consistent with the proposed changes in the State's NPDES Mining Rules.

COMMENT

No questions.

47CSR5A – Individual State Certification of Activities Requiring a Federal Permit

SUMMARY

The proposed amendments to this rule are being made to adopt into rule requirements that have been applied through past practices for coal related activities requiring mitigation and issuance of a 401 State Certification of a 404 Permit. Ratios for monetary compensation for temporary impacts are detailed. Monetary compensation for permanent impacts to wetlands from coal related activities are made the same as non-coal related. Additional economic and stream measurement information is being requested to be added to the 401 application.

COMMENT

Mr. Harris: How do we determine the "ordinary high water mark" under section 4.2.f.4 and how is it determined on a small stream?

DEP Response: The US Army Corps of Engineers is responsible for determining "waters of the U.S." under the rule.

Mr. Harris: What are the differences between coal and non-coal impacts and how are they determined?

DEP Response: Rule has to be consistent with statute.

47CSR30 – WV/NPDES Rules for Coal Mining Facilities

SUMMARY

The proposed amendments to this rule are being made to allow general clean-up of sections referencing outdated names of agencies and references to the EQB governing rule making. This rule addresses the Secretary as being the person as head of all actions. References to the "Director" are changed to "Secretary" to eliminate the need to distinguish between the Director of Mining and Reclamation and the Director of Water and Waste Management when issuing a coal related WV/NPDES permit. This rule adds provision for storm-water coverage for certain minimal activities without the requirement for modification through application to the permit. This rule also provides for an advanced approval of transfer of a WV/NPDES Permit to coincide with the advanced approval of the corresponding Article 3 Permit. This rule clarifies provisions related to coal remining operations and provides a remining water quality standard variance for any parameter of concern.

COMMENT

No questions.

199CSR1 - Surface Mining Blasting Rule

SUMMARY

The proposed amendments change the following sections: 2.27. Adds the definition of "other structure" (structures built by the permittee); 2.38 Clarifies definition of "surface mine operation"; 3.2.C. Plan for blasting should include seismic monitoring when within 1000 ft of a structure, and performance specifications for blasting seismographs; 3.4. Areas of blasting that will be regulated for shaft and slope development; 3.6.c.3. Requiring field practice guidelines for blasting seismographs; 3.7a Request for alternate limits must have written consent of the owner; 3.9. Minimum qualifications and continuing education requirements for surveyor; 4.1.b. Allows the agency to consider blasting experience of applicants that was gained prior to the last three years; 4.5.d. Requires applicants who have been suspended or revoked in other states to show cause as to why should be issued a certification; 4.9.a.2 process for issuing a temporary suspension to a blaster and appeal rights; 4.13 Clarifies blasters responsibility of training the blasting crew; 5.2.a.3&4 Clarifies

the investigations process on a claim of blasting damage; 6.1 Requiring that any arbitrators that are removed from the list must be done with cause; and 7.3 Detonators and initiation systems are not considered for calculation of fees.

COMMENT

No questions.

Office of Oil and Gas

35CSR3 – Coalbed Methane Wells Rule

SUMMARY

The WVDEP, Office of Oil and Gas is proposing to revise existing rule 35CSR3. Series 3 is a legislative rule in place to enforce the provisions in WV Code §22-21-1 et seq., Coalbed Methane Wells and Units, commonly referred to at the Coalbed Methane Act. The revisions will: Address the establishment of special field rules to promote the orderly development of coalbed methane fields; Protect the correlative rights of all owners located within the geographic area for which special field rules are established; Provide a process by which the Review Board may hold a hearing on an application for special field rules and issue such rules; Insert language (Section 17) which was inadvertently deleted from the rule during the 2006 legislative session. This language existed in the rule prior to the revisions in 2006.

COMMENT

Is this the same rule that went through last year?

DEP Response: Yes, except for two sections that had changes:

16.2.e – advertisement "15 days"

16.1.6.1 – "FOIA" issue that came out of the LRMRC.

Mr. Raney: Is this the product of the stakeholders group?

DEP Response: Yes.

Ms. Hallinan: What is a field rule?

DEP Response: Special spacing procedure for coalbed methane wells. It deals with pooling and royalty issues.

Division of Land Restoration

33CSR10 – Recycling Assistance Grant Program

SUMMARY

This rule sets out guidelines and procedures for providing assistance grants to local governments and other interested parties for the purpose of planning, initiating, expanding, or upgrading recycling programs, provide related public education programs, and assist in recycling market procurement efforts.

COMMENT

No questions.

60CSR3 – Voluntary Remediation and Redevelopment Rule

SUMMARY

This legislative rule establishes the eligibility, procedures, standards and legal documents required for voluntary and brownfield cleanups and updates risk protocol standards, including updates to the deminimis table. It also includes changes to the land use covenant section to incorporate the components of the Uniform Covenant Act.

COMMENT

Ms. Dooley: Are there grant dollars for brownfields?

DEP Response: Yes

The next scheduled Advisory Council Meeting will be on May 30, 2007 at 10:00 a.m. Mr. Huffman asked the Council members to notify the DEP of which rules they want to discuss so the right agency person can be at the meeting. He also asked them to submit comments prior to the meeting if possible.

DO, temperature, and fecal coliform. We feel that they can assess these parameters and should not treat them separately.

45CSR42 Greenhouse Gases

The fact that the DEP is beginning to deal with the process of greenhouse gases that lead to global warming is commendable. Some questions on the rule were raised by Dr. Kotcon:

The greenhouse gases emissions inventory rule (45-42-1) needs to be
>strengthened considerably. The sections on emissions inventory
>(section 5, pages 3-4) is so vague as to be meaningless, especially
>as it deals with sequestration for area sources and sinks. I do not
>see how any meaningful data can be generated with this language.
How would the carbon sequestration be estimated? Has there been studies estimating the biogenic incorporation of CO2 per acre of woodland, for example? The rule appears to be a vague in how it would be implemented.

Air Quality and Emission Rules (see below)

45CSR8 Ambient Air Quality Standards

Don Garvin pointed out that the the antidegradation language was removed from this rule, and it was explained that the agency feels these provisions are now covered in 45-CSR-14("Prevention of Significant Deterioration.") However, the language that was stricken does not appear in 45-CSR-14, and the stricken language is the ONLY statement in the rules of West Virginia's antidegradation policy for air quality. The environmental community still believes the stricken language should be restored.

Here is what should be reinstated:

§45-8-2. Anti-Degradation Policy.

2.1. Pursuant to the best interests of the State of West Virginia, it is the objective of the Secretary to obtain and maintain the cleanest air possible, consistent with the best available technology.

2.2. Where the present ambient air is of better quality than the established standards, the Secretary will develop long-range plans to protect the difference between the present quality and the established standards. The plans will be based upon the best available forecasts of probable land and air uses in these areas of high air quality.

2.3. The air quality of these areas will not be lowered unless it has been clearly demonstrated to the Secretary that such a change is justifiable as a result of necessary economic or social development and will not result in statutory air pollution. This will require that any industrial, public, or private project or development which could constitute a new source of air pollutants, within an area of such high air quality, provide the best practicable control available under existing technology as part of the initial project or development.

45CSR41 Control of Annual SO2 emissions

45CSR6 Control of Air Pollution from Refuse Combustion

45CSR39 Nitrogen Oxides

I raised the general concern whether the standards for air quality were consistent with the EPA guidelines or not. Further, were any recognized health authorities consulted when these levels were determined? I also raised the issue that West Virginia is increasing supplying electricity to the population east of our mountains. New transmission lines are proposed that are to be connected with coal burning power plants. Billy Jack Gregg, Consumer Advocate for the WV PSC has pointed out that the states receiving our generated power will not permit generation plants in their region. They are concerned about air pollution and its various effects. But they need power, so they turn to West Virginia. This helps the coal industry and generation plants, but puts the health of West Virginians in jeopardy. I feel that our air quality and emission limits should be even more stringent than the EPA calls for in order to protect our citizens. This should be particularly true for power plants that export electricity.

Dr. Kotcon has raised the following issues:

45-CSR-8 Ambient Air Quality Standards

The standards for PM2.5 and Ozone are not adequately protective. I recommend that the standards be lowered from 15 $\mu g/m^3$ to 13 $\mu g/m^3$ in section 4.2.b., and from 0.08 ppm to 0.07 ppm in section 4.4.b.

The air standards (45-8-1) retains the standards for PM2.5 and ozone
>that the EPA Clean Air Scientific Advisory Council has already
>determined to be inadequate. Keeping these old standards will kill
>dozens or hundreds of West Virginians each year.

>The rule on refuse combustion (45-6-1) attempts to revise the
>definition of low-level radioactive waste and revives the
>Below-Regulatory_Concern (BRC) issue from some years ago. It also
>creates a large number of exemptions for "temporary" pollution
>sources. I am not yet sure if this re-opens old battles over
>medical waste incineration, but this was a really hot issue a few
>years back.

Comment submitted by Karen Price at Council meeting 5/30/07

Questions/Comments on DEP's 2007 Proposed Rules

- **45 CSR 8 Ambient Air Quality Standards**

Section 4.2.c – $PM_{2.5}$ Maximum 24-Hour Average Concentration. The level for the 24-hour primary and secondary standard states 35 ug/m^3. This should be 65 ug/m^3, pursuant to 40 CFR 50.7.

- **45 CSR 39, 45 CSR 40, 45 CSR 41**

The opt-in unit language is deleted from each of these rules. What is the purpose for the deletion of these provisions?

- **33 CSR 30, Underground Storage Tank Rules**

Section 6.1. states "....including any person who accepts a delivery order, accepts payment, delivers or deposits product into an underground storage tank.....". The portion that states "....accepts payment...." should be removed from this section because those individuals within a company who accept payment or make payments most often do not know anything about the underground storage tank (UST), the operation of the UST, or the current regulatory status of the UST.

Section 7.3.a.1. states " ...the methodology for verifying attendance, the date, time and location of the course, the name of the offering organization, the credentials of the instructors, and a certification that the technology or methods....."

1. The portion that states " ..the date, time and location of the course,...." should be deleted. For large companies with many UST installations and locations there can be numerous individuals that need to be trained. Training will most likely occur on multiple dates, times, and locations that may not always be known until just prior to the training event. When new employees are hired training might

occur on short notice and for one individual. The burden of having to repor the dates, time and locations would hinder and slow down the training process and restrict a company's ability to comply.

2. The portion that states "..the credentials of the instructors..." should be removed. Credentials will vary from instructor to instructor new instructors might be utilized, and a company might not know which instructors will be used at the various training sessions until just prior to the training session. In addition, the course content is the main issue of concern and should be the main focus in obtaining State approval of a training program.

Section 7.3.a.2 - This section states that a nonrefundable application fee of $280 must be submitted with the application. Larger companies may have one training program, but administer the training on multiple dates, times and locations. Having to submit an application for approval of the training program each time the program is administered would be cost prohibitive, burdensome, and would hinder the training process. The State should clarify or make provision for a company to submit one application for the training program that will be administered to all company UST facilities. This will make the $280 application fee reasonable and the application process less burdensome

APPENDIX B

FISCAL NOTE FOR PROPOSED RULES

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

Type of Rule: ___X__ Legislative _____ Interpretive _____ Procedural

Agency: Division of Air Quality

Address: 601 57th Street SE

Charleston, WV 25304

Phone Number: 926-0475 Email: tmowrer@wvdep.org

Fiscal Note Summary

Summarize in a clear and concise manner what impact this measure will have on costs and revenues of state government.

No impact above that resulting from currently applicable federal emission standards.

Fiscal Note Detail

Show over-all effect in Item 1 and 2 and, in Item 3, give an explanation of Breakdown by fiscal year, including long-range effect.

FISCAL YEAR

Effect of Proposal	2008 Increase/Decrease (use "-")	2009 Increase/Decrease (use "-")	Fiscal Year (Upon Full Implementation)
1. Estimated Total Cost	$ 0	$ 0	$ 0
Personal Services	0	0	0
Current Expenses	0	0	0
Repairs & Alterations	0	0	0
Assets	0	0	0
Equipment	0	0	0
Other	0	0	0
2. Estimated Total Revenues	0	0	0

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

3. Explanation of above estimates (including long-range effect):
Please include any increase or decrease in fees in your estimated total revenues.

Costs anticipated to be incurred in the implementation of federal rules promulgated under 40 CFR Part 60 as of June 1, 2007 are included in prior cost estimates prepared for state implementation of Title V of the Clean Air Act, as amended, under 45CSR30. Full Title V program approval was issued by the U.S. Environmental Protection Agency on November 19, 2001.

MEMORANDUM

Please identify any areas of vagueness, technical defects, reasons the proposed rule **would not** have a fiscal impact, and/or any special issues **not** captured elsewhere on this form.

Date: June 1, 2007

Signature of Agency Head or Authorized Representative

John A. Benedict, Director

RECEIVED

2007 JUL 26 PM 4:35

SECRETARY OF STATE
STATE OF WEST VIRGINIA

TITLE 45
LEGISLATIVE RULE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
~~OFFICE~~ DIVISION OF AIR QUALITY

SERIES 16
STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES
~~PURSUANT TO 40 CFR PART 60~~

§45-16-1. General.

1.1. Scope. -- This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 CFR Part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. -- W.Va. Code §22-5-4.

1.3. Filing Date. -- ~~April 28, 2006~~.

1.4. Effective Date. -- ~~June 1, 2006~~.

1.5. Incorporation By Reference. -- Federal Counterpart Regulation. The Secretary has determined that a federal counterpart rule exists, and in accordance with the Secretary's recommendation, with limited exception, this rule incorporates by reference 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, ~~June 1, 2005~~ June 1, 2007.

1.6. Former Rules. -- This legislative rule amends 45CSR16 "Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60" which was filed ~~May 20, 2005~~ April 28, 2006, and which became effective ~~June 1, 2005~~ June 1, 2006.

§45-16-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or his or her authorized representative.

2.2. "Clean Air Act" ("CAA") means 42 U.S.C. §7401 et seq.

2.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§22-1-6 or 22-1-8.

2.4. Other words and phrases used in this rule, unless otherwise indicated, ~~will~~ shall have the meaning ascribed to them in 40 CFR Part 60. Words and phrases not defined therein ~~will~~ shall have the meaning given to them in the federal Clean Air Act.

§45-16-3. Requirements.

3.1. No person may construct, reconstruct, modify, or operate or cause to be constructed, reconstructed, modified, or operated any source subject to the provisions of 40 CFR Part 60 which results or will result in a violation of this rule.

§45-16-4. Adoption of Standards.

4.1. Standards. -- The Secretary hereby adopts and incorporates by reference the provisions of 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, including any reference methods, performance specifications

and other test methods which are appended to these standards and contained in 40 CFR Parts 60 and 65, effective ~~June 1, 2005~~ June 1, 2007, for the purposes of implementing a program for standards of performance for new stationary sources, except as follows:

4.1.a. 40 CFR §60.9 is amended to provide that information ~~will~~ shall be available to the public in accordance with W.Va. Code §§22-5-1 et seq., 29B-1-1 et seq., and 45CSR31; and

4.1.b. Subparts B, C, Ca, Cb, Cc, Cd, Ce, Ea, Eb, Ec, WWW, AAAA, BBBB, CCCC, DDDD, EEEE, FFFF, and HHHH of 40 CFR Part 60 ~~will~~ shall be excluded.

§45-16-5. Secretary.

5.1. Any and all references in 40 CFR Parts 60 and 65 to the "Administrator" are amended to be the "Secretary" except as follows:

5.1.a. where the federal regulations specifically provide that the Administrator ~~will~~ shall retain authority and not transfer authority to the Secretary;

5.1.b. where provisions occur which refer to:

5.1.b.1. alternate means of emission limitations;

5.1.b.2. alternate control technologies;

5.1.b.3. innovative technology waivers;

5.1.b.4. alternate test methods;

5.1.b.5. alternate monitoring methods;

5.1.b.6. waivers/adjustments to recordkeeping and reporting;

5.1.b.7. emissions averaging;

5.1.b.8. applicability determinations; or

5.1.b.9. the authority to require testing under Section 114 of the Clean Air Act, as amended; or

5.1.c. where the context of the regulation clearly requires otherwise.

§45-16-6. Permits.

6.1. Nothing contained in this adoption by reference ~~must~~ shall be construed or inferred to mean that permit requirements in accordance with applicable rules ~~will~~ shall be in any way be limited or inapplicable.

§45-16-7. Inconsistency Between Rules.

7.1. In the event of any inconsistency between this rule and any other rule of the West Virginia Department of Environmental Protection, the inconsistency ~~will~~ shall be resolved by the determination of the Secretary and the determination ~~will~~ shall be based upon the application of the more stringent provision, term, condition, method or rule.

of agency organization, procedure, or practice that do not substantially affect the rights or obligations of non-agency parties. 5 U.S.C. 804(3). EPA is not required to submit a rule report regarding today's action under section 801 because this is a rule of particular applicability establishing source-specific requirements for one named source.

C. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by January 16, 2007. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action, to approve the removal of the Consent Agreement for Burlington Industries, Clarksville, Virginia, may not be challenged later in proceedings to enforce its requirements.

(See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: November 3, 2006.

Donald S. Welsh,

Regional Administrator, Region III.

■ 40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart VV—Virginia

§ 52.2420 [Amended]

■ 2. In § 52.2420, the table in paragraph (d) is amended by removing the entry for Burlington Industries.

[FR Doc. E6–19272 Filed 11–15–06; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2006–0497; FRL–8243–2]

RIN 2060–AN96

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: New source performance standards (NSPS) limiting emissions of, among other pollutants, nitrogen oxides (NO_X) from industrial-commercial-institutional steam generating units capable of combusting more than 100 million British thermal units (Btu) per hour were promulgated on November 25, 1986. The standards limit NO_X emissions from the combustion of fossil fuels either solely or in combination with other fuels or wastes. The standards include provisions for the establishment of facility-specific NO_X standards for steam generating units which simultaneously combust fossil fuel and chemical byproduct/waste under certain conditions. This amendment promulgates a facility-specific NO_X standard for a steam generating unit which simultaneously combusts fossil fuel and chemical byproduct offgas at the Innovene USA LLC facility located in Lima, Ohio.

DATES: This direct final rule will be effective on January 16, 2007 without further notice, unless EPA receives material adverse comments by December 18, 2006, unless a hearing is requested by November 27, 2006. If a timely hearing request is submitted, the hearing will be held on December 1, 2006 and we must receive written comments on or before January 2, 2007. If EPA receives such comments, it will publish a timely withdrawal in the **Federal Register** indicating the amendment is being withdrawn due to adverse comments.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2006–0497, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–1741.
- *Mail:* Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 6102T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* Air and Radiation Docket and Information Center, U.S. EPA, 1301 Constitution Avenue, NW., Room B102, Washington, DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

We request that a separate copy also be sent to the contact person listed below (see **FOR FURTHER INFORMATION CONTACT**).

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2006–0497. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov,* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC,

EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

Note: The EPA Docket Center suffered damage due to flooding during the last week of June 2006. The Docket Center is continuing to operate. However, during the cleanup, there will be temporary changes to Docket Center telephone numbers, addresses, and hours of operation for people who wish to visit the Public Reading Room to view documents. Consult EPA's **Federal Register** notice at 71 FR 38147 (July 5, 2006) or the EPA Web site at *http://www.epa.gov/epahome/dockets.htm* for current information on docket status, locations, and telephone numbers. The Docket Center's mailing address for U.S. mail and the procedure for submitting comments to *http://www.regulations.gov* are not affected by the flooding and will remain the same.

FOR FURTHER INFORMATION CONTACT: Mr. James A. Eddinger, Energy Strategies Group, Emission Standards Division (D243–01), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5426; facsimile number (919) 541–5450; electronic mail address *eddinger.jim@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. The only regulated entity that will be affected by this direct final rule amendment is the Innovene USA facility located in Lima, Ohio.

Comments. We are publishing this direct final rule without prior proposal because we view it as noncontroversial and do not anticipate adverse comments. However, in the Proposed Rules section of today's **Federal Register**, we are publishing a separate document that will serve as the proposal in the event that adverse comments are filed. If we receive any adverse comments on a specific element of this direct final rule, we will publish a timely withdrawal in the **Federal Register** informing the public that the amendment is being withdrawn due to adverse comment. We will address all public comments in a subsequent final rule based on the proposed rule. The amendment in this direct final rule will become effective on the date set out above if we do not receive adverse comment. We will not institute a second comment period on this direct final rule. Any parties interested in commenting must do so at this time.

World Wide Web (WWW). In addition to being available in the docket, electronic copies of this direct final rule will be posted on the Technology Transfer Network's (TTN) policy and guidance information page *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this direct final rule is available only on the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by January 16, 2007. Under section 307(d)(7)(B) of the CAA, only an objection to this direct final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements that are subject to this action may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background

The objective of the NSPS, promulgated on November 25, 1986, is to limit NO_X emissions from the combustion of fossil fuel. For steam generating units combusting byproduct/waste, the requirements of the NSPS vary depending on the mode of operation of the steam generating units. During periods when only fossil fuel is combusted, the steam generating unit must comply with the NO_X emission limits in the NSPS for fossil fuel. During periods when only byproduct/waste is combusted, the steam generating unit may be subject to other requirements or regulations which limit NO_X emissions, but it is not subject to NO_X emission limits under the NSPS. In addition, if the steam generating unit is subject to federally enforceable permit conditions limiting the amount of fossil fuel combusted in the steam generating unit to an annual capacity factor of 10 percent or less, the steam generating unit is not subject to NO_X emission limits under the NSPS when it simultaneously combusts fossil fuel and byproduct/waste.

With the exception noted above, during periods when fossil fuel and byproduct/waste are simultaneously combusted in a steam generating unit, the unit must generally comply with NO_X emission limits under 40 CFR 60.44b(e) of the NSPS. Under 40 CFR 60.44b(e) the applicable NO_X emission limit depends on the nature of the byproduct/waste combusted. In some situations, however, "facility-specific" NO_X emission limits developed under 40 CFR 60.44b(f) may apply. The order for determining which NO_X emission limit applies is as follows. A steam generating unit simultaneously combusting fossil fuel and byproduct/waste is expected to comply with the NO_X emission limit under 40 CFR 60.44b(e); only in a few situations may NO_X emission limits developed under 40 CFR 60.44b(f) apply. An equation in 40 CFR 60.44b(e) is included to determine the NO_X emission limit applicable to a steam generating unit when it simultaneously combusts fossil fuel and byproduct/ waste.

Only where a steam generating unit which simultaneously combusts fossil fuel and byproduct/waste is unable to comply with the NO_X emission limit determined under 40 CFR 60.44b(e), might a facility-specific NO_X emission limit under 40 CFR 60.44b(f) apply. That section permits a steam generating unit to petition the Administrator for a facility-specific NO_X emission limit. A facility-specific NO_X emission limit will be proposed and promulgated by the Administrator for the steam generating unit only where the petition is judged to be complete. To be considered complete, a petition for a facility-specific NO_X standard under 40 CFR 60.44b(f) consists of three components. To satisfy the first component, the steam generating unit must demonstrate compliance with the NO_X emission limit when combusting fossil fuel alone. This provision ensures that the steam generating unit has installed best demonstrated NO_X control technology, identified the NO_X control technology, and identified the manner in which this technology is operated to achieve compliance with the NO_X emission limit for fossil fuel.

To satisfy the second component, the steam generating unit must demonstrate

that the NO_X control technology does not comply with the NO_X emission limit when the unit simultaneously combusts fossil fuel and chemical byproduct/waste. The unit must demonstrate this non-compliance under the same operating conditions used to demonstrate compliance with fossil fuel alone. In addition, the steam generating unit must identify what unique and specific properties of the chemical byproduct/waste are responsible for preventing compliance with the NO_X emission limit for fossil fuel. Byproduct/waste is defined in subpart Db as being a liquid or gaseous substance.

Thirdly, the steam generating unit must provide data and/or analyses to support a facility-specific NO_X standard that represents the emissions while simultaneously combusting fossil fuel and chemical byproduct/waste. The unit must perform these analyses while operating the NO_X control technology under the same conditions used to demonstrate compliance with the NO_X emission limit for fossil fuel, if only fossil fuel were combusted. In addition to identifying the NO_X emission limit, the unit must identify appropriate testing, monitoring, reporting and recordkeeping procedures to ensure proper operation of the NO_X control technology and minimize NO_X emissions at all times.

Upon receipt of a complete petition, the Administrator will propose a facility-specific NO_X standard for the steam generating applicable during those times when it simultaneously combusts chemical byproduct/waste with fossil fuel. The NO_X standard will include the NO_X emission limit(s) and/or operating parameter limit(s) to ensure proper operation of the NO_X control technology at all times, as well as appropriate testing, monitoring, reporting and recordkeeping requirements.

Innovene USA LLC has submitted a petition requesting that EPA adopt a facility-specific NO_X standard for the absorber offgas incinerator (AOGI) at its acrylonitrile production process facility in Lima, Ohio. The AOGI contains a steam generating heat recovery section which qualifies the AOGI as a steam generating unit subject to NSPS subpart Db. The AOGI combusts natural gas to incinerate the offgas from the reactor and absorber section of the acrylonitrile production process. The AOGI was installed to destroy the volatile organic compounds and hazardous air pollutants (HAP) in the vent stream generated by the acrylonitrile manufacturing process. While the AOGI is designed to comply with Subpart Db while firing natural gas, the combustion of the offgas with natural gas in the AOGI results in a NO_X emission rate in excess of the NSPS limit.

II. What Is EPA Finalizing Under This Action?

Based on a review of the Innovene USA's petition for an alternative NO_X standard, EPA's Office of Air Quality Planning and Standards has determined the petition to be complete and an alternative facility-specific standard to be appropriate. This determination is appropriate because the AOGI is designed to minimize the formation of NO_X from the combustion of the fuel as well as the formation of NO_X generated by the nitrogen bound organic compounds in the offgas. The alternative NO_X standard is based on analysis of NO_X emissions continuously monitored during operation of the AOGI while burning the offgas. An alternative NO_X standard of 1.5 pounds per million Btu heat input is provided in the final rule amendment. EPA also indicates reporting and recordkeeping requirements for the owner or operator of the AOGI.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under the Executive Order.

B. Paperwork Reduction Act

This action imposes no new information collection requirements on the industry. Because there is no additional burden on the industry as a result of this action, the information collection requests have not been revised. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations 40 CFR Part 60, Subpart Db under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0072, EPA ICR number 1088.10. A copy of the OMB approved Information Collection Request (ICR) may be obtained from Susan Auby, Collection Strategies Division; U.S. Environmental Protection Agency (2822T); 1200 Pennsylvania Ave., NW., Washington, DC 20460 or by calling (202) 566–1672.

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

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for our regulations are listed in 40 CFR part 9 and 40 CFR chapter 15.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of the direct final rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kilowatt-hr per year of electricity usage, depending on the size definition for the affected North American Industry Classification System code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of the direct final rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities. This direct final rule will not impose any requirements on small entities because it does not impose any additional regulatory requirements.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with this final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed, under section 203 of the UMRA, a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of our regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this direct final rule amendment does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year, nor does this direct final rule significantly or uniquely impact small governments, because it contains no requirements that apply to such governments or impose obligations upon them. Thus, the requirements of sections 202 and 205 of the UMRA do not apply to the direct final rule.

E. Executive Order 13132: Federalism

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

This direct final rule does not have federalism implications. It will not have new substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This action codifies a facility-specific NO_X standard. There are minimal, if any, impacts associated with this action. Thus, Executive Order 13132 does not apply to the direct final rule.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

This direct final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the direct final rule.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This direct final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

This direct final rule is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in our regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

These direct final rule amendments do not involve technical standards. Therefore, this direct final rule is not subject to NTTAA.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this direct final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of this direct final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**.

This direct final rule is not a "major rule" as defined by 5 U.S.C. section 804(2). The direct final rule amendments are effective on January 16, 2007.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: November 9, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of Federal Regulations is amended to read as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401 *et seq.*

Subpart Db—[Amended]

■ 2. Section 60.49b is amended by adding paragraph (y) to read as follows:

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(y) Facility-specific nitrogen oxides standard for Innovene USA's AOGI located in Lima, Ohio:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the nitrogen oxides emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the nitrogen oxides emission limit is 645 ng/J (1.5 lb/million Btu).

(2) *Emission monitoring for nitrogen oxides.* (i) The nitrogen oxides emissions shall be determined by the compliance and performance test methods and procedures for nitrogen oxides in § 60.46b.

(ii) The monitoring of the nitrogen oxides emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[FR Doc. E6–19386 Filed 11–15–06; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 239 and 258

[EPA–R07–RCRA–2006–0877; FRL–8242–9]

Adequacy of Missouri Municipal Solid Waste Landfill Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: This action approves Missouri's Research, Development and Demonstration (RD&D) permit program and updates to the approved Municipal Solid Waste Landfill Permit (MSWLP) program. On March 22, 2004, the EPA issued final regulations allowing RD&D permits to be issued to certain municipal solid waste landfills by approved states. On April 14, 2006, Missouri submitted an application to the EPA seeking Federal approval of its RD&D requirements and to update Federal approval of its MSWLP program.

DATES: This direct final determination is effective January 16, 2007, without further notice unless EPA receives adverse comments by December 18, 2006. If adverse comments are received, EPA will publish a timely response or withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will or will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R07–RCRA–2006–0877, by one of the following methods:

1. *http://www.regulations.gov.* Follow the on-line instruction for submitting comments.

2. *E-mail: Mclaughlin.chilton@epa.gov.*

3. *Mail:* Send written comments to Chilton McLaughlin, EPA Region 7, Solid Waste/Pollution Prevention Branch, 901 North 5th Street, Kansas City, Kansas 66101.

4. *Hand Delivery or Courier.* Deliver your comments to Chilton McLaughlin, EPA Region 7, Solid Waste/Pollution Prevention Branch, 901 North 5th Street, Kansas City, Kansas 66101.

Instructions: Direct your comments to Docket ID No. EPA–R07–RCRA–2006–0877. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit through *http://www.regulations.gov* or e-mail information that you consider to be CBI or otherwise protected. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the electronic docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Environmental Protection Agency, Solid Waste/Pollution Prevention Branch, 901 North 5th Street, Kansas City, Kansas 66101. The Regional Office's official hours of business are Monday through Friday, 8 to 4:30, excluding Federal holidays. The interested persons wanting to examine these documents should make an appointment with the office at least 24 hours in advance.

FOR FURTHER INFORMATION CONTACT: Chilton McLaughlin at (913) 551–7666, or by e-mail at *Mclaughlin.chilton@epa.gov.*

SUPPLEMENTARY INFORMATION:

Administrative Procedure Act at 5 U.S.C. 553(d)(1).

The proposed rule was published in the **Federal Register** (71 FR 13792) on March 17, 2006, with a 60-day period for notice and comment consistent with the requirements of 5 U.S.C. 553(b).

List of Subjects in 36 CFR Part 7

National Parks, Reporting and recordkeeping requirements.

■ In consideration of the foregoing, the National Park Service amends 36 CFR part 7 as follows:

PART 7—SPECIAL REGULATIONS, AREAS OF THE NATIONAL PARK SYSTEM

■ 1. The authority for part 7 continues to read as follows:

Authority: 16 U.S.C. 1, 3, 9a, 460(q), 462(k); Sec. 7.96 also issued under D.C. Code 8–137(1981) and D.C. Code 40–721 (1981).

■ 2. Add new paragraph (d) to § 7.51 to read as follows:

§ 7.51 Curecanti Recreation Area.

* * * * *

(d) *Personal Watercraft (PWC).* PWC may operate within Curecanti National Recreation Area in the following designated areas and under the following conditions:

(1) PWC may operate and land on Blue Mesa Reservoir between Beaver Creek and Blue Mesa dam, except that PWC may not operate in the buoyed barricaded section in the vicinity of the dam.

(2) PWC must operate at "flat wake" speeds within Blue Mesa Reservoir in the following areas upstream of designated buoys:

(i) Soap Creek arm at approximate longitude 107°8′9″ N latitude 38°30′16″ W.

(ii) West Elk arm at approximate longitude 107°16′45″ N latitude 38°29′43″ W.

(iii) Cebolla arm at approximate longitude 107°12′16″ N latitude 38°27′37″ W.

(iv) Lake Fork arm at approximate longitude 107°18′19″ N latitude 38°27′2″ W.

(3) PWC must operate at "flat wake" speeds in the following areas:

(i) Within 100′ of shoreline inside Dry Creek cove.

(ii) Within 500′ of shoreline along old highway 50 and Bay of Chickens.

(iii) Within the buoyed area around Elk Creek and Lake Fork marinas.

(iv) Within the buoyed area at Iola, Stevens Creek, and Ponderosa boat launch.

(v) From Lake city bridge east to Beaver Creek.

(vi) Within 100′ of shoreline adjacent to Stevens Creek campground.

(4) PWC may only be launched from designated boat launch sites.

(5) The Superintendent may temporarily limit, restrict or terminate access to the areas designated for PWC use after taking into consideration public health and safety, natural and cultural resource protection, and other management activities and objectives.

David M. Verhey,

Acting Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 06–7846 Filed 9–20–06; 8:45 am]

BILLING CODE 4312–52–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 60

[EPA–OAR–2004–0510; FRL–8221–4]

RIN 2060–AF83

Methods for Measurement of Visible Emissions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes Methods 203A, 203B, and 203C for determining visible emissions using data reduction procedures that are more appropriate for State Implementation Plan (SIP) rules than Method 9, the method currently used. This action was requested by the States and is needed for the special data reduction requirements in their rules. The intended effect is to provide States with an expanded array of data reduction procedures for determining compliance with their SIP opacity regulations.

In addition, this action amends various testing provisions in the New Source Performance Standards (NSPS) to correct inadvertent errors and amend a testing provision.

DATES: This final rule is effective on September 21, 2006.

ADDRESSES: EPA has established a docket for this action under Docket ID No. OAR–2004–0510. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket, Docket ID No. OAR–2004–0510, EPA Docket Center (EPA/DC), EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Robin Segall, Measurement Technology Group (E143–02), Air Quality Assessment Division, EPA, Research Triangle Park, North Carolina 27711; telephone (919) 541–0893; fax number (919) 541–0516; electronic mail address: *segall.robin@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by the final rule include the following:

TABLE 1.—MAJOR ENTITIES POTENTIALLY AFFECTED BY THIS ACTION

Examples of regulated entities	SIC codes	NAICS codes
Fossil Fuel Steam Generators	4931	221112
Industrial, Commercial, Institutional Steam Generating Units	4961	22133
Electric Generating	4911	221119
Portland Cement Plants	3241	327310
Petroleum Refineries	2911	324110
Hot Mix Asphalt Facilities	2951	324121
Kraft Pulp Mills	2611	3221
Municipal Solid Waste	4953	562213

TABLE 1.—MAJOR ENTITIES POTENTIALLY AFFECTED BY THIS ACTION—Continued

Examples of regulated entities	SIC codes	NAICS codes
Secondary Lead Smelters	3341	331492
Secondary Brass and Bronze Production Plants	3351	331421
Basic Oxidation Process Furnaces	3312	331111
Sewage Treatment Plants	4952	221320
Coal Preparation Plants	1221	212111
Ferroalloy Production Facilities	3313	331112
Electric Arc Furnaces	3312	331111
Glass Manufacturing Plants	3211	327211
Grain Elevators	0111	111141
Lime Manufacturing Plants	2812	325181
Metallic Mineral Processing Plants	1011	212210
Non-Metallic Mineral Processing Plants	1411	212311
Phosphate Rock Plants	1475	212392
Ammonium Sulfate Manufacturing Facilities	2873	325311
Asphalt Processing	2952	3244122
Asphalt Roofing Manufacturing	2952	324122
Calciners and Dryers in Mineral Industries	1479	212393

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. This table lists examples of the types of entities EPA is now aware could potentially be affected by the final rule. Other types of entities not listed could also be affected. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. How can I access electronic copies of this document and other related information?

In addition to being available in the docket, an electronic copy of today's final rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of the final rule will be placed on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under Section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by November 20, 2006. Under Section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Under CAA section 307(b)(2), the requirements established by the final rule may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

D. Outline

The information presented in this preamble is organized as follows:

II. Background and Summary of Proposed Rule

In 1974, Method 9 of Appendix A to 40 CFR part 60 was revised. In the preamble to that rule, we recognized that the Method 9 data reduction techniques were not appropriate for some types of State implementation plan (SIP) opacity regulations. The preamble also stated the Agency's intent to propose procedures to enforce SIP limitations that were not adequately addressed by Method 9. Such SIP limitations included those with time-exception provisions (a specified number of minutes in an hour in which the opacity limit may be exceeded), as well as those that specify averaging times other than the 6 minutes advocated by Method 9. Also, Method 9 did not address data reduction procedures for instantaneous opacity limitations which are included in some SIP. In order to provide appropriate data reduction procedures for opacity limits that differ from Method 9, we proposed new test procedures for evaluating compliance with opacity standards in 1986.

The 1986 proposal contained field and observer certification procedures identical to those of Method 9, the only difference being the data reduction procedures for determining compliance with SIP regulations that contained time-exception, time-averaged, and instantaneous limitations. The 1986 proposal indicated that we would select the visible emission test method and data reduction procedures that best ensured enforcement of the SIP opacity standard in a manner consistent with the original language in the federally-

approved or promulgated SIP. We also proposed procedures for analyzing fugitive dust.

Between this 1986 proposal and the proposal of Methods 203A, B, and C in 1993, technical work continued in several areas. We completed a collaborative study of the effect of shorter observation intervals, and we developed several implementation tools, including a revised sample visible emissions observation (VEO) form to assist States in specifying the appropriate test method for the opacity limit proposed in the SIP or SIP revision.

The proposal of Methods 203A, B, and C divided the procedures proposed in 1986 into three distinct methods, allowing a State to specify the exact data reduction procedures to be used in compliance determinations. The three methods incorporated the certification procedures for observers from Method 9 without change. The only procedural differences between Methods 203A, B, and C and Method 9 are in the provisions for recording observations and data reduction.

Since the 1993 proposal of Methods 203A, B, and C, we are not aware of any new methods or changes to existing methods that would lead to substantial changes in our approach. Therefore, with one exception, we believe it is appropriate to complete this action with the changes noted in the preamble. We are not taking final action at this time with regard to procedures for fugitive dust.

III. Responses to Comments

A. Stringency of Current Standards Not Affected

The most frequent comment concerned the possibility of current regulations being affected by these new methods. Examples of these concerns are: (1) Method 203B would increase the stringency of current time-exception regulations, (2) Methods 203A, B, and C would displace Tennessee's four federally approved visible emission methods, and (3) decreasing the averaging time demands an increase in the level of the standard.

Methods 203A, B, and C are not retroactive; they do not apply to existing regulations. Methods 203A, 203B, and 203C are example methods for States to use in developing their SIP regulations. The addition of these methods to Appendix M of Part 51 will increase the number of opacity methods available to the State and will not affect the stringency of any existing standard.

A comment regarding the data reduction procedures of Method 203B expressed a similar concern. Some current time-exception methods count the number of 1-minute averages that are over the maximum opacity specified. The sum of 1-minute averages must not exceed the number of exception-minutes specified in the applicable standard. Method 203B contains slightly different data reduction procedures in which the readings are not averaged, but each reading is viewed as a 15-second block of time. The number of readings above the specified opacity limit is multiplied by 0.25 resulting in the total number of minutes during which the maximum opacity level is exceeded. Method 203B is a slightly more stringent procedure than summing 1-minute averages. As mentioned above, Methods 203A, B, and C are not retroactive and the stringency of visible emission procedures need to be taken into account when the new or revised emission limits are developed.

B. Four Readings Not a Reliable Data Sample

We proposed two options when using Method 203C: Averaging four 15-second readings or averaging twelve 5-second readings. One commenter stated that four 15-second readings were not sufficient for Method 203C. Upon further review and examination of the data, we agree with the commenter and have eliminated the four 15-second reading option. Only the second option, averaging twelve 5-second readings, is prescribed in Method 203C.

We also received comments on the proposed procedures for fugitive dust. However, because we are not taking final action on these procedures at this time, we are not responding to the comments here.

IV. Changes to Proposed Methods 203A, B, and C

A. Performance Results Added to the Methods

The error associated with each method has been summarized from various field studies and is presented in Section 13 of each method.

B. 15-Second Interval Option Removed From Method 203C

The proposed option to use four 15-second readings for instantaneous limitation regulations has been removed from Method 203C. Twelve 5-second readings will be used when Method 203C is specified for instantaneous regulations.

V. Summary of Amendments to the NSPS

Technical amendments are being made to 40 CFR Part 60 to correct existing errors in Subparts J, BB, and Appendix B and to amend a testing requirement in Subpart WWW. These technical amendments were proposed in the **Federal Register** on August 5, 2005 (70 FR 45608). No comments were received from the public concerning these amendments.

A. Petroleum Refineries (Subpart J)

In § 60.106(b)(3) of the petroleum refinery NSPS, the equation for determining the coke burn-off rate is being corrected.

B. Kraft Pulp Mills (Subpart BB)

In § 60.284 of the kraft pulp mills NSPS, an inadvertent paragraph requiring that continuous emission monitors be subject to the quality assurance provisions of Appendix F is being deleted.

C. Municipal Solid Waste Landfills (Subpart WWW)

In § 60.752(b)(2)(iii)(A) of the municipal solid waste landfill NSPS, open flares are required to comply with the general flare provisions of § 60.18. In these provisions, the heat content of the flare gas is determined from an analysis of its organic compound and hydrogen content using Methods 18 and ASTM D1946, respectively. Methane is the primary organic compound of significance in landfill gas, and hydrogen is not likely to be present. Method 3C is easier to use than Method 18 and has a more appropriate measurement range for the methane levels encountered at landfills. In addition, Method 3C determines oxygen and nitrogen which are needed to determine the flare gas exit velocity. In the past, sources have requested and received permission to used Method 3C in place of Methods 18 and ASTM D1946 under this rule. This amendment makes Method 3C the required test method for methane and removes the requirement to measure hydrogen by ASTM D1946.

D. Performance Specification 2, Appendix B of Part 60

In Performance Specification 2, an inadvertent omission in an October 17, 2000 amendment removed an allowance for low-emitters when conducting relative accuracy tests. This amendment reinstates the allowance.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735 October 4, 1993), the Agency must determine whether the regulatory

action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, Local, or Tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

We have determined that this rule is not a "significant regulatory action" under the terms of Executive Order 12866 and is therefore not subject to OMB review. We have determined that this regulation would result in none of the economic effects set forth in Section 1 of the Order because it does not impose emission measurement requirements beyond those specified in the current regulations, nor does it change any emission standard.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The new test methods do not add information collection requirements beyond what is currently mandated.

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

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9.

C. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Entities potentially affected by this action include those listed in Table 1 of **SUPPLEMENTARY INFORMATION.**

After considering the economic impacts of today's final rule on small entities, we have concluded that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities.

D. Unfunded Mandates Reform Act

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

Today's rule contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for State, local, or tribal governments or the private sector. The rule imposes no enforceable duty on any State, local, or tribal governments or the private sector. In any event, EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Thus, today's rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. This rule simply makes available alternative data reduction procedures that States can use at their discretion under their SIP opacity regulations.

E. Executive Order 13132: Federalism

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

This rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this rule.

F. Executive Order 13175: Consultation and Coordination With Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This final rule does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. In this final rule, we are simply adding test methods at the request of the States to increase the flexibility in testing for opacity of emissions. Thus, Executive Order 13175 does not apply to this rule.

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

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

This action is not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272), directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices, *etc.*) that are developed or adopted by VCS bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS. During this rulemaking, we identified no VCS that might be applicable. Specifically, there were none that addressed opacity data reduction provisions differently than what currently exists in Method 9 of 40 CFR Part 60, Appendix A.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12848 (58 FR 7629, February 11, 1994) requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. This rule contains optional test procedures that do not place disproportionate human health or environmental effects of minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after its publication in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective.

List of Subjects in 40 CFR Parts 51 and 60

Administrative practice and procedure, Air pollution control, Carbon monoxide, Continuous emission monitors, Environmental protection, Intergovernmental relations, Lead, New sources, Nitrogen dioxide, Ozone, Particulate matter, Performance specifications, Reporting and recordkeeping requirements, Sulfur oxides, Test methods and procedures, Volatile organic compounds.

Dated: September 14, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 51—[AMENDED]

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

■ 2. Appendix M is amended by numerically adding the following method titles at the beginning of Appendix M and by numerically adding Methods 203A, 203B, and 203C as follows:

Appendix M to Part 51—Recommended Test Methods for State Implementation Plans

* * * * *

Method 203A—Visual Determination of Opacity of Emissions from Stationary Sources for Time-Averaged Regulations.

Method 203B—Visual Determination of Opacity of Emissions from Stationary Sources for Time-Exception Regulations.

Method 203C—Visual Determination of Opacity of Emissions from Stationary Sources for Instantaneous Regulations.

* * * * *

Method 203A—Visual Determination of Opacity of Emissions from Stationary Sources for Time-Averaged Regulations

1.0 Scope and Application

What is Method 203A?

Method 203A is an example test method suitable for State Implementation Plans (SIP) and is applicable to the determination of the opacity of emissions from sources of visible emissions for time-averaged regulations. A time-averaged regulation is any regulation that requires averaging visible emission data to determine the opacity of visible emissions over a specific time period.

Method 203A is virtually identical to EPA's Method 9 of 40 CFR Part 60, Appendix A, except for the data-reduction procedures, which provide for averaging times other than 6 minutes. Therefore, using Method 203A with a 6-minute averaging time would be the same as following EPA Method 9. The certification procedures for this method are

identical to those provided in Method 9 and are provided here, in full, for clarity and convenience. An example visible emission observation form and instructions for its use can be found in reference 7 of Section 17 of Method 9.

2.0 Summary of Method

The opacity of emissions from sources of visible emissions is determined visually by an observer certified according to the procedures in Section 10 of this method. Readings taken every 15 seconds are averaged over a time period specified in the applicable regulation ranging from 2 minutes to 6 minutes.

3.0 Definitions [Reserved]

4.0 Interferences [Reserved]

5.0 Safety [Reserved]

6.0 Equipment and Supplies

What equipment and supplies are needed?

6.1 Stop Watch. Two watches are required that provide a continuous display of time to the nearest second.

6.2 Compass (optional). A compass is useful for determining the direction of the emission point from the spot where the visible emissions (VE) observer stands and for determining the wind direction at the source. For accurate readings, the compass should be magnetic with resolution better than 10 degrees. It is suggested that the compass be jewel-mounted and liquid-filled to dampen the needle swing; map reading compasses are excellent.

6.3 Range Finder (optional). Range finders determine distances from the observer to the emission point. The instrument should measure a distance of 1000 meters with a minimum accuracy of ±10 percent.

6.4 Abney Level (optional). This device for determining the vertical viewing angle should measure within 5 degrees.

6.5 Sling Psychrometer (optional). In case of the formation of a steam plume, a wet- and dry-bulb thermometer, accurate to 0.5 °C, are mounted on a sturdy assembly and swung rapidly in the air in order to determine the relative humidity.

6.6 Binoculars (optional). Binoculars are recommended to help identify stacks and to characterize the plume. An 8 x 50 or 10 x 50 magnification, color-corrected coated lenses and rectilinear field of view is recommended.

6.7 Camera (optional). A camera is often used to document the emissions before and after the actual opacity determination.

6.8 Safety Equipment. The following safety equipment, which should be approved by the Occupational Safety and Health Association (OSHA), is recommended: orange or yellow hard hat, eye and ear protection, and steel-toed safety boots.

6.9 Clipboard and Accessories (optional). A clipboard, several ball-point pens (black ink recommended), a rubber band, and several visible emission observation forms facilitate documentation.

7.0 Reagents and Standards [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport

What is the Test Procedure?

An observer qualified in accordance with Section 10 of this method must use the following procedures to visually determine the opacity of emissions from stationary sources.

8.1 Procedure for Emissions from Stacks. These procedures are applicable for visually determining the opacity of stack emissions by a qualified observer.

8.1.1 Position. You must stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140-degree sector to your back. Consistent with maintaining the above requirement as much as possible, you must make opacity observations from a position such that the line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (*e.g.*, roof monitors, open baghouses, non-circular stacks), approximately perpendicular to the longer axis of the outlet. You should not include more than one plume in the line of sight at a time when multiple plumes are involved and, in any case, make opacity observations with the line of sight perpendicular to the longer axis of such a set of multiple stacks (*e.g.*, stub stacks on baghouses).

8.1.2 Field Records. You must record the name of the plant, emission location, type of facility, observer's name and affiliation, a sketch of the observer's position relative to the source, and the date on a field data sheet. An example visible emission observation form can be found in reference 7 of Section 17 of this method. You must record the time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background on the field data sheet at the time opacity readings are initiated and completed.

8.1.3 Observations. You must make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Do not look continuously at the plume but, instead, observe the plume momentarily at 15-second intervals.

8.1.3.1 Attached Steam Plumes. When condensed water vapor is present within the plume as it emerges from the emission outlet, you must make opacity observations beyond the point in the plume at which condensed water vapor is no longer visible. You must record the approximate distance from the emission outlet to the point in the plume at which the observations are made.

8.1.3.2 Detached Steam Plumes. When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, you must make the opacity observation at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

8.2 Recording Observations. You must record the opacity observations to the nearest 5 percent every 15 seconds on an observational record sheet such as the example visible emission observation form in reference 7 of Section 17 of this method. Each observation recorded represents the average opacity of emissions for a 15-second period. The overall length of time for which observations are recorded must be appropriate to the averaging time specified in the applicable regulation.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization

10.1 What are the Certification Requirements? To receive certification as a qualified observer, you must be trained and knowledgeable on the procedures in Section 8.0 of this method, be tested and demonstrate the ability to assign opacity readings in 5 percent increments to 25 different black plumes and 25 different white plumes, with an error not to exceed 15 percent opacity on any one reading and an average error not to exceed 7.5 percent opacity in each category. You must be tested according to the procedures described in Section 10.2 of this method. Any smoke generator used pursuant to Section 10.2 of this method must be equipped with a smoke meter which meets the requirements of Section 10.3 of this method. Certification tests that do not meet the requirements of Sections 10.2 and 10.3 of this method are not valid.

The certification must be valid for a period of 6 months, and after each 6-month period, the qualification procedures must be repeated by an observer in order to retain certification.

10.2 What is the Certification Procedure? The certification test consists of showing the candidate a complete run of 50 plumes, 25 black plumes and 25 white plumes, generated by a smoke generator. Plumes must be presented in random order within each set of 25 black and 25 white plumes. The candidate assigns an opacity value to each plume and records the observation on a suitable form. At the completion of each run of 50 readings, the score of the candidate is determined. If a candidate fails to qualify, the complete run of 50 readings must be repeated in any retest. The smoke test may be administered as part of a smoke school or training program, and may be preceded by training or familiarization runs of the smoke generator during which candidates are shown black and white plumes of known opacity.

10.3 Smoke Generator.

10.3.1 What are the Smoke Generator Specifications? Any smoke generator used for the purpose of Section 10.2 of this method must be equipped with a smoke meter installed to measure opacity across the diameter of the smoke generator stack. The smoke meter output must display in-stack opacity, based upon a path length equal to the stack exit diameter on a full 0 to 100 percent chart recorder scale. The smoke meter optical design and performance must meet the specifications shown in Table 203A–1 of this method. The smoke meter must be calibrated as prescribed in Section 10.3.2 of this method prior to conducting each smoke reading test. At the completion of each test, the zero and span drift must be checked and, if the drift exceeds ±1 percent opacity, the condition must be corrected prior to conducting any subsequent test runs. The smoke meter must be demonstrated at

the time of installation to meet the specifications listed in Table 203A–1 of this method. This demonstration must be repeated following any subsequent repair or replacement of the photocell or associated electronic circuitry including the chart recorder or output meter, or every 6 months, whichever occurs first.

10.3.2 How is the Smoke Meter Calibrated? The smoke meter is calibrated after allowing a minimum of 30 minutes warm-up by alternately producing simulated opacity of 0 percent and 100 percent. When a stable response at 0 percent or 100 percent is noted, the smoke meter is adjusted to produce an output of 0 percent or 100 percent, as appropriate. This calibration must be repeated until stable 0 percent and 100 percent readings are produced without adjustment. Simulated 0 percent and 100 percent opacity values may be produced by alternately switching the power to the light source on and off while the smoke generator is not producing smoke.

10.3.3 How is the Smoke Meter Evaluated? The smoke meter design and performance are to be evaluated as follows:

10.3.3.1 Light Source. You must verify from manufacturer's data and from voltage measurements made at the lamp, as installed, that the lamp is operated within 5 percent of the nominal rated voltage.

10.3.3.2 Spectral Response of the Photocell. You must verify from manufacturer's data that the photocell has a photopic response; *i.e.*, the spectral sensitivity of the cell must closely approximate the standard spectral-luminosity curve for photopic vision which is referenced in (b) of Table 203A–1 of this method.

10.3.3.3 Angle of View. You must check construction geometry to ensure that the total angle of view of the smoke plume, as seen by the photocell, does not exceed 15 degrees. Calculate the total angle of view as follows:

$\varphi_v = 2 \tan^{-1} (d/2L)$

Where:

φ_v = Total angle of view
d = The photocell diameter + the diameter of the limiting aperture
L = Distance from the photocell to the limiting aperture.

The limiting aperture is the point in the path between the photocell and the smoke plume where the angle of view is most restricted. In smoke generator smoke meters, this is normally an orifice plate.

10.3.3.4 Angle of Projection. You must check construction geometry to ensure that the total angle of projection of the lamp on the smoke plume does not exceed 15 degrees. Calculate the total angle of projection as follows:

$\varphi_p = 2 \tan^{-1} (d/2L)$

Where:

φ_p = Total angle of projection
d = The sum of the length of the lamp filament + the diameter of the limiting aperture
L = The distance from the lamp to the limiting aperture.

10.3.3.5 Calibration Error. Using neutral-density filters of known opacity, you must check the error between the actual response and the theoretical linear response of the smoke meter. This check is accomplished by first calibrating the smoke meter according to Section 10.3.2 of this method and then inserting a series of three neutral-density filters of nominal opacity of 20, 50, and 75 percent in the smoke meter path length. Use filters calibrated within 2 percent. Care should be taken when inserting the filters to prevent stray light from affecting the meter. Make a total of five non-consecutive readings for each filter. The maximum opacity error on any one reading shall be ±3 percent.

10.3.3.6 Zero and Span Drift. Determine the zero and span drift by calibrating and operating the smoke generator in a normal manner over a 1-hour period. The drift is measured by checking the zero and span at the end of this period.

10.3.3.7 Response Time. Determine the response time by producing the series of five simulated 0 percent and 100 percent opacity values and observing the time required to reach stable response. Opacity values of 0 percent and 100 percent may be simulated by alternately switching the power to the light source off and on while the smoke generator is not operating.

11.0 Analytical Procedures [Reserved]

12.0 Data Analysis and Calculations

12.1 Time-Averaged Regulations. A set of observations is composed of an appropriate number of consecutive observations determined by the averaging time specified (*i.e.*, 8 observations for a two minute average). Divide the recorded observations into sets of appropriate time lengths for the specified averaging time. Sets must consist of consecutive observations; however, observations immediately preceding and following interrupted observations shall be deemed consecutive. Sets need not be consecutive in time and in no case shall two sets overlap. For each set of observations, calculate the average opacity by summing the opacity readings taken over the appropriate time period and dividing by the number of readings. For example, for a 2-minute average, eight consecutive readings would be averaged by adding the eight readings and dividing by eight.

13.0 Method Performance

13.1 Time-averaging Performances. The accuracy of test procedures for time-averaged regulations was evaluated through field studies that compare the opacity readings to a transmissometer. Analysis of these data shows that, as the time interval for averaging increases, the positive error decreases. For example, over a 2-minute time period, 90 percent of the results underestimated opacity or overestimated opacity by less than 9.5 percent opacity, while over a 6-minute time period, 90 percent of the data have less than a 7.5 percent positive error. Overall, the field studies demonstrated a negative bias. Over a 2-minute time period, 57 percent of the data have zero or negative error, and over a 6-minute time period, 58 percent of the data have zero or negative error. This means that observers are more likely to assign opacity values that are below, rather than above, the actual opacity value. Consequently, a larger percentage of noncompliance periods will be reported as compliant periods rather than compliant periods reported as violations. Table 203A–2 highlights the precision data results from the June 1985 report: "Opacity Errors for Averaging and Non Averaging Data Reduction and Reporting Techniques."

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures [Reserved]

17.0 References

1. U.S. Environmental Protection Agency. Standards of Performance for New Stationary Sources; Appendix A; Method 9 for Visual Determination of the Opacity of Emissions from Stationary Sources. Final Rule. 39 FR 219. Washington, DC. U.S. Government Printing Office. November 12, 1974.

2. Office of Air and Radiation. "Quality Assurance Guideline for Visible Emission Training Programs." EPA–600/S4–83–011. Quality Assurance Division. Research Triangle Park, NC. May 1982.

3. Office of Research and Development. "Method 9—Visible Determination of the Opacity of Emissions from Stationary Sources." February 1984. Quality Assurance Handbook for Air Pollution Measurement Systems. Volume III, Section 3.1.2. Stationary Source Specific Methods. EPA–600–4–77–027b. August 1977. Office of Research and Development Publications, 26 West Clair Street, Cincinnati, OH.

4. Office of Air Quality Planning and Standards. "Opacity Error for Averaging and Non-averaging Data Reduction and Reporting Techniques." Final Report–SR–1–6–85. Emission Measurement Branch, Research Triangle Park, NC. June 1985.

5. U.S. Environmental Protection Agency. Preparation, Adoption, and Submittal of State Implementation Plans. Methods for Measurement of PM_{10} Emissions from Stationary Sources. Final Rule. **Federal Register**. Washington, DC. U.S. Government Printing Office. Volume 55, No. 74. Pages 14246–14279. April 17, 1990.

6. Office of Air Quality Planning and Standards. "Collaborative Study of Opacity Observations of Fugitive Emissions from Unpaved Roads by Certified Observers." Emission Measurement Branch, Research Triangle Park, NC. October 1986.

7. Office of Air Quality Planning and Standards. "Field Data Forms and Instructions for EPA Methods 203A, 203B, and 203C." EPA 455/R–93–005. Stationary Source Compliance Division, Washington, DC, June 1993.

18.0 Tables, Diagrams, Flowcharts, and Validation Data

TABLE 203A–1.—SMOKE METER DESIGN AND PERFORMANCE SPECIFICATIONS

Parameter	Specification
a. Light Source	Incandescent lamp operated at nominal rated voltage.
b. Spectral response of photocell	Photopic (daylight spectral response of the human eye—Citation 3).
c. Angle of view	15° maximum total angle.
d. Angle of projection	15° maximum total angle.
e. Calibration error	±3% opacity, maximum.
f. Zero and span drift	±1% opacity, 30 minutes
g. Response time	5 seconds.

TABLE 203A–2.—PRECISION BETWEEN OBSERVERS: OPACITY AVERAGING

Averaging period	Number of observations	Standard deviation (% opacity)	Amount with <7.5% opacity difference
15-second	140,250	3.4	87
2 minutes	17,694	2.6	92
3 minutes	11,836	2.4	92
6 minutes	5,954	2.1	93

Method 203B—Visual Determination of Opacity of Emissions From Stationary Sources for Time-Exception Regulations

1.0 Scope and Application

What is Method 203B?

Method 203B is an example test method suitable for State Implementation Plans (SIPs) and is applicable to the determination of the opacity of emissions from sources of visible emissions for time-exception regulations. A time-exception regulation means any regulation that allows predefined periods of opacity above the otherwise applicable opacity limit (*e.g.*, allowing exceedances of 20 percent opacity for 3 minutes in 1 hour.)

Method 203B is virtually identical to EPA's Method 9 of 40 CFR part 60, Appendix A, except for the data-reduction procedures, which have been modified to apply to time-exception regulations. The certification procedures for this method are identical to those provided in Method 9. An example of a visible emission observation form and instructions for its use can be found in reference 7 of Section 17 of Method 203A.

2.0 Summary of Method

The opacity of emissions from sources of visible emissions is determined visually by a qualified observer.

3.0 Definitions [Reserved]

4.0 Interferences [Reserved]

5.0 Safety [Reserved]

6.0 Equipment and Supplies

What equipment and supplies are needed?

The same as specified in Section 6.0 of Method 203A.

7.0 Reagents and Standards [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport

What is the Test Procedure?

The observer qualified in accordance with Section 10 of Method 203A must use the following procedures for visually determining the opacity of emissions.

8.1 Procedures for Emissions From Stationary Sources. The procedures for emissions from stationary sources are the same as specified in 8.1 of Method 203A.

8.2 Recording Observations. You must record opacity observations to the nearest 5 percent at 15-second intervals on an observational record sheet. Each observation recorded represents the average opacity of emissions for a 15-second period. The overall length of time for which observations are recorded must be appropriate to the applicable regulation.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization

The Calibration and Standardization requirements are the same as specified in Section 10 of Method 203A.

11.0 Analytical Procedures [Reserved]

12.0 Data Analysis and Calculations

Data Reduction for Time-Exception Regulations. For a time-exception regulation, reduce opacity observations as follows: Count the number of observations above the applicable standard and multiply that number by 0.25 to determine the minutes of emissions above the target opacity.

13.0 Method Performance

13.1 Time-Exception Regulations. "Opacity Errors for Averaging and Non-Averaging Data Reduction and Reporting Techniques" analyzed the time errors associated with false compliance or false non-compliance determinations resulting from a sample of 1110 opacity readings with 6-minute observation periods. The study applied a 20 percent opacity standard. Fifty-one percent of the data showed zero error in time determinations. The standard deviation was 97.5 seconds for the 6-minute time period.

13.1.1 Overall, the study showed a negative bias. Each reading is associated with a 15-second block of time. The readings were multiplied by 15 seconds and the resulting time spent above the standard was compared to the transmissometer results. The average amount of time that observations deviated from the transmissometer's determinations was –8.3 seconds. Seventy percent of the time determinations were either correct or underestimated the time of excess emissions. Consequently, a larger percentage of noncompliance periods would be reported as compliant periods rather than compliant periods reported as violations.

13.1.2 Some time-exception regulations reduce the data by averaging over 1-minute periods and then counting those minutes above the standard. This data reduction procedure results in a less stringent standard than determinations resulting from data reduction procedures of Method 203B.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures [Reserved]

17.0 References

The references are the same as specified in Section 17 of Method 203A.

18.0 Tables, Diagrams, Flowcharts, and Validation Data [Reserved]

Method 203C—Visual Determination of Opacity of Emissions From Stationary Sources for Instantaneous Limitation Regulations

1.0 Scope and Application

What is Method 203C?

Method 203C is an example test method suitable for State Implementation Plans (SIPs) and is applicable to the determination of the opacity of emissions from sources of visible emissions for regulations with an instantaneous opacity limitation. An instantaneous opacity limitation is an opacity limit which is never to be exceeded.

Method 203C is virtually identical to EPA's Method 9 of 40 CFR Part 60, Appendix A, except for 5-second reading intervals and the data-reduction procedures, which have been modified for instantaneous limitation regulations. The certification procedures for

this method are virtually identical to Method 9. An example visible emission observation form and instructions for its use can be found in reference 7 of Section 17 of Method 203A.

2.0 Summary of Method

The opacity of emissions from sources of visible emissions is determined visually by an observer certified according to the procedures in Section 10 of Method 203A.

3.0 Definitions [Reserved]

4.0 Interferences [Reserved]

5.0 Safety [Reserved]

6.0 Equipment and Supplies

The equipment and supplies used are the same as Section 6.0 of Method 203A.

7.0 Reagents and Standards [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport

What is the Test Procedure?

The qualified observer must use the following procedures for visually determining the opacity of emissions.

8.1 Procedures for Emissions From Stationary Sources. These are the same as Section 8.1 of Method 203A.

8.1.1 Position. Same as Section 8.1.1 of Method 203A.

8.1.2 Field Records. Same as Section 8.1.2 of Method 203A.

8.1.3 Observations. Make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Do not look continuously at the plume, instead, observe the plume momentarily at *5-second* intervals.

8.1.3.1 Attached Steam Plumes. Same as Section 8.1.3.1 of Method 203A.

8.1.3.2 Detached Steam Plumes. Same as Section 8.1.3.2 of Method 203A.

8.2 Recording Observations. You must record opacity observations to the nearest 5 percent at 5-second intervals on an observational record sheet. Each observation recorded represents the average of emissions for the 5-second period. The overall time for which recordings are made must be of a length appropriate to the applicable regulation for which opacity is being measured.

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization

The calibration and standardization procedures are the same as Section 10 of Method 203A.

11.0 Analytical Procedures [Reserved]

12.0 Data Analysis and Calculations

12.1 Data Reduction for Instantaneous Limitation Regulations. For an instantaneous limitation regulation, a 1-minute averaging time will be used. You must divide the observations recorded on the record sheet into sets of consecutive observations. A set is composed of the consecutive observations made in 1 minute. Sets need not be consecutive in time, and in no case must two sets overlap. You must reduce opacity observations by dividing the sum of all observations recorded in a set by the number of observations recorded in each set.

12.2 Reduce opacity observations by averaging 12 consecutive observations recorded at 5-second intervals. Divide the observations recorded on the record sheet into sets of 12 consecutive observations. For each set of 12 observations, calculate the average by summing the opacity of the 12 observations and dividing this sum by 12.

13.0 Method Performance

The results of the "Collaborative Study of Opacity Observations at Five-second Intervals by Certified Observers" are almost identical to those of previous studies of Method 9 observations taken at 15-second intervals and indicate that observers can make valid observations at 5-second intervals. The average difference of all observations from the transmissometer values was 8.8 percent opacity, which shows a fairly high negative bias. Underestimating the opacity of the visible emissions is more likely than overestimating the opacity of the emissions.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures [Reserved]

17.0 References

The references are the same as references 1–7 in Method 203A in addition to the following:

1. Office of Air Quality Planning and Standards. "Collaborative Study of Opacity Observations at Five-second Intervals by Certified Observers." Docket A–84–22, IV–A–2. Emission Measurement Branch, Research Triangle Park, N.C. September 1990.

18.0 Tables, Diagrams, Flowcharts, and Validation Data

* * * * *

PART 60—[AMENDED]

■ 3. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7413, 7414, 7416, 7601, and 7602.

■ 4. Amend § 60.106(b)(3) by revising the equation to read as follows:

§ 60.106 Test methods and procedures.

* * * * *

(b) * * *

(3) * * *

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO/2 + \%CO_2 + \%O_2)$$

* * * * *

■ 5. Revise § 60.284(f) to read as follows:

§ 60.284 Monitoring of emissions and operations.

* * * * *

(f) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems required under this section. All continuous monitoring systems shall be operated in accordance with the applicable procedures under Performance Specifications 1, 3, and 5 of appendix B of this part.

§ 60.752 [Amended]

■ 6. Revise § 60.752(b)(2)(iii)(A) to read as follows:

§ 60.752 Standards for air emissions from municipal solid waste landfills.

* * * * *

(b) * * *

(2) * * *

(iii) * * *

(A) An open flare designed and operated in accordance with § 60.18 except as noted in § 60.754(e);

* * * * *

§ 60.754 [Amended]

■ 7. Amend § 60.754 by adding paragraph (e) to read as follows:

§ 60.754 Test Methods and Procedures.

* * * * *

(e) For the performance test required in § 60.752(b)(2)(iii)(A), the net heating value of the combusted landfill gas as determined in § 60.18(f)(3) is calculated from the concentration of methane in the landfill gas as measured by Method 3C. A minimum of three 30-minute Method 3C samples are determined. The measurement of other organic components, hydrogen, and carbon monoxide is not applicable. Method 3C may be used to determine the landfill gas molecular weight for calculating the flare gas exit velocity under § 60.18(f)(4).

■ 8. In Appendix A–7, Method 24 is amended by adding Section 6.7 to read as follows:

Appendix A–7 to Part 60—Test Methods 19 Through 25E

* * * * *

Method 24—Determination of Volatile Matter Content, Water Content, Density, Volume Solids, and Weight Solids of Surface Coatings

* * * * *

6.7 ASTM D 6419–00, Test Method for Volatile Content of Sheet-Fed and Coldset Web Offset Printing Inks.

* * * * *

■ 9. In Appendix B, Performance Specification 2 is amended by adding a sentence to the end of Section 13.2 to read as follows:

Appendix B to Part 60—Performance Specifications

* * * * *

Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources

* * * * *

13.2 * * * For SO_2 emission standards of 130 to and including 86 ng/J (0.30 and 0.20 lb/million Btu), inclusive, use 15 percent of the applicable standard; below 86 ng/J (0.20 lb/million Btu), use 20 percent of the emission standard.

* * * * *

[FR Doc. 06–7907 Filed 9–20–06; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

44 CFR Part 64

[Docket No. FEMA–7945]

Suspension of Community Eligibility

AGENCY: Mitigation Division, Federal Emergency Management Agency (FEMA), Department of Homeland Security.

ACTION: Final rule.

SUMMARY: This rule identifies communities, where the sale of flood insurance has been authorized under the National Flood Insurance Program (NFIP), that are scheduled for suspension on the effective dates listed within this rule because of noncompliance with the floodplain management requirements of the program. If FEMA receives documentation that the community has adopted the required floodplain management measures prior to the effective suspension date given in this rule, the suspension will not occur and a notice of this will be provided by publication in the **Federal Register** on a subsequent date.

EFFECTIVE DATES: The effective date of each community's scheduled suspension is the third date ("Susp.") listed in the third column of the following tables.

ADDRESSES: If you want to determine whether a particular community was suspended on the suspension date, contact the appropriate FEMA Regional Office.

FOR FURTHER INFORMATION CONTACT: David Stearrett, Mitigation Division, 500 C Street, SW., Washington, DC 20472, (202) 646–2953.

SUPPLEMENTARY INFORMATION: The NFIP enables property owners to purchase flood insurance which is generally not otherwise available. In return, communities agree to adopt and administer local floodplain management aimed at protecting lives and new construction from future flooding. Section 1315 of the National Flood Insurance Act of 1968, as amended, 42 U.S.C. 4022, prohibits flood insurance coverage as authorized under the NFIP, 42 U.S.C. 4001 *et seq.*; unless an appropriate public body adopts adequate floodplain management measures with effective enforcement measures. The communities listed in this document no longer meet that statutory requirement for compliance with program regulations, 44 CFR part 59 *et seq.* Accordingly, the communities will be suspended on the effective date in the third column. As of that date, flood insurance will no longer be available in the community. However, some of these communities may adopt and submit the required documentation of legally enforceable floodplain management measures after this rule is published but prior to the actual suspension date. These communities will not be suspended and will continue their eligibility for the sale of insurance. A notice withdrawing the suspension of the communities will be published in the **Federal Register**.

In addition, FEMA has identified the Special Flood Hazard Areas (SFHAs) in these communities by publishing a Flood Insurance Rate Map (FIRM). The date of the FIRM, if one has been published, is indicated in the fourth column of the table. No direct Federal financial assistance (except assistance pursuant to the Robert T. Stafford Disaster Relief and Emergency Assistance Act not in connection with a flood) may legally be provided for construction or acquisition of buildings in identified SFHAs for communities not participating in the NFIP and identified for more than a year, on FEMA's initial flood insurance map of the community as having flood-prone areas (section 202(a) of the Flood Disaster Protection Act of 1973, 42 U.S.C. 4106(a), as amended). This prohibition against certain types of Federal assistance becomes effective for the communities listed on the date shown in the last column. The Administrator finds that notice and public comment under 5 U.S.C. 553(b) are impracticable and unnecessary because communities listed in this final rule have been adequately notified.

Each community receives 6-month, 90-day, and 30-day notification letters addressed to the Chief Executive Officer stating that the community will be suspended unless the required floodplain management measures are met prior to the effective suspension date. Since these notifications were made, this final rule may take effect within less than 30 days.

National Environmental Policy Act. This rule is categorically excluded from the requirements of 44 CFR part 10, Environmental Considerations. No environmental impact assessment has been prepared.

Regulatory Flexibility Act. The Administrator has determined that this rule is exempt from the requirements of the Regulatory Flexibility Act because the National Flood Insurance Act of 1968, as amended, 42 U.S.C. 4022, prohibits flood insurance coverage unless an appropriate public body adopts adequate floodplain management measures with effective enforcement measures. The communities listed no longer comply with the statutory requirements, and after the effective date, flood insurance will no longer be available in the communities unless remedial action takes place.

Regulatory Classification. This final rule is not a significant regulatory action under the criteria of section 3(f) of Executive Order 12866 of September 30, 1993, Regulatory Planning and Review, 58 FR 51735.

Executive Order 13132, Federalism. This rule involves no policies that have federalism implications under Executive Order 13132.

Executive Order 12988, Civil Justice Reform. This rule meets the applicable standards of Executive Order 12988.

Paperwork Reduction Act. This rule does not involve any collection of information for purposes of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

List of Subjects in 44 CFR Part 64

Flood insurance, Floodplains.

■ Accordingly, 44 CFR part 64 is amended as follows:

PART 64—[AMENDED]

■ 1. The authority citation for part 64 is revised to read as follows:

Authority: 42 U.S.C. 4001 *et seq.*; Reorganization Plan No. 3 of 1978, 3 CFR, 1978 Comp.; p. 329; E.O. 12127, 44 FR 19367, 3 CFR, 1979 Comp.; p. 376.

§ 64.6 [Amended]

■ The tables published under the authority of § 64.6 are amended as follows:

Federal Register

Tuesday,
July 11, 2006

Part II

Environmental Protection Agency

40 CFR Parts 60, 85 et al.
Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 85, 89, 94, 1039, 1065, and 1068

[EPA–HQ–OAR–2005–0029, FRL–8190–7]

RIN 2060–AM82

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating standards of performance for stationary compression ignition (CI) internal combustion engines (ICE). The standards will implement section 111(b) of the Clean Air Act (CAA) and are based on the Administrator's determination that stationary CI ICE cause, or contribute significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare. The intended effect of the standards is to require all new, modified, and reconstructed stationary CI ICE to use the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts, not just with add-on controls, but also by eliminating or reducing the formation of these pollutants. The final standards will reduce nitrogen oxides (NO_x) by an estimated 38,000 tons per year (tpy), particulate matter (PM) by an estimated 3,000 tpy, sulfur dioxide (SO_2) by an estimated 9,000 tpy, non-methane hydrocarbons (NMHC) by an estimated 600 tpy, and carbon monoxide (CO) by an estimated 18,000 tpy in the year 2015.

DATES: The final rule is effective on September 11, 2006. The incorporation by reference of a certain publication listed in the final rule is approved by the Director of the Federal Register as of September 11, 2006.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0029. We also rely on documents in Docket ID No. EPA–HQ–OAR–2003–0012 and incorporate that docket into the record for the final rule. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (202) 566–1742. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for EPA Docket Center is (202) 566–1742. As of the date of signature, the physical docket is temporarily unavailable due to flooding, but interested members of the public can receive the list of documents in the docket or any particular documents electronically by accessing the electronic docket or by calling the contact person. We hope that the physical docket will be accessible again before publication.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagán, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; electronic mail address *pagan.jaime@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any manufacturer that produces or any industry using a stationary internal combustion engine as defined in the final rule.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	335312	Motor and generator manufacturing.
	33391	Pump and compressor manufacturing.
	333992	Welding and soldering equipment manufacturing.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your engine is regulated by this action, you should examine the applicability criteria in § 60.4200 of the final rule. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule will be available on the WWW through the Technology Transfer Network Web site (TTN). Following signature, EPA will post a copy of the final rule on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under CAA section 307(b)(1), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by September 11, 2006. Under CAA section 307(d)(7)(B), only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under CAA section 307(b)(2), the requirements established by this final action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the same

time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Background Information Document. EPA proposed new source performance standards (NSPS) for CI ICE on July 11, 2005 (70 FR 39870), and received 47 comment letters on the proposal. A background information document (BID) ("Response to Public Comments on Proposed Standards of Performance for Stationary Compression Ignition Internal Combustion Engines,") containing EPA's responses to each public comment and the Economic Impact Analysis Report are available in Docket ID No. EPA–HQ–OAR–2005–0029.

Organization of This Document. The following outline is provided to aid in locating information in the preamble.

I. Background

This action promulgates NSPS that will apply to new stationary CI ICE. New source performance standards implement section 111(b) of the CAA, and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The standards apply to new stationary sources of emissions, *i.e.*, sources whose construction, reconstruction, or modification begins after a standard for those sources is proposed. NSPS require these sources to control emissions to the level achievable by best demonstrated technology (BDT), considering costs and any non-air quality health and environmental impacts and energy requirements.

II. Summary of the Final Rule

A. What is the source category regulated by the final rule?

The final rule applies to stationary CI ICE. A stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines. A CI engine means a type of stationary internal combustion engine that is not a spark ignition (SI) engine. A SI engine means a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are SI engines.

B. What are the pollutants regulated by the final rule?

The pollutants to be regulated by the final rule are NO_X, PM, CO, and NMHC.[1] Emissions of sulfur oxides (SO_X) will also be reduced through the use of lower sulfur fuel. Smoke emissions will also be reduced through the implementation of the final standards. Emissions of hazardous air pollutants (HAP) from these engines have been, or will be, regulated in separate rulemakings promulgated under CAA section 112.[2]

C. What sources are subject to the final rule?

The affected source for the CI ICE NSPS is each stationary CI internal combustion engine whose construction, modification or reconstruction commenced after July 11, 2005. The date of construction is the date the engine is ordered by the owner or operator. Stationary CI ICE manufactured prior to April 1, 2006, that are not fire pump engines are not subject to the final rule, unless the engines are modified or reconstructed after July 11, 2005. Stationary fire pump CI ICE manufactured prior to July 1, 2006, are not subject to the final rule either, unless the engines are modified or reconstructed after July 11, 2005. Manufacturers of 2007 and later model year stationary CI ICE that are not fire pumps are subject to the final rule. For fire pump engines, the date of manufacturing is the date the engine is built into a certified National Fire Protection Association (NFPA) fire pump engine. Manufacturers of fire

[1] Primarily for reasons of testing ease and because engine manufacturers are familiar with testing for NMHC, this rule, as with previous rules promulgating emission standards for mobile source internal combustion engines, uses NMHC rather than VOC as the metric for measuring organic compounds that can contribute to ozone formation. C.f. 40 CFR part 60, Method 25 (Determination of Total Gaseous Nonmethane Organic Emissions as Carbon.)

[2] Emissions of HAP from stationary reciprocating internal combustion engines (RICE) located at major sources were the subject of a final rule published on June 15, 2004 (69 FR 33473). Emissions of HAP from other stationary RICE will be the subject of another rulemaking that will be promulgated no later than December 20, 2007.

pump engines are subject to the final rule beginning with the first model year that new fire pump engines in a particular horsepower class must meet standards more stringent than Tier 1 standards, which can be any model year from 2008 to 2011, depending on the horsepower of the engine.

Owners and operators of new stationary CI ICE who are subject to the final rule (as discussed above) must meet the requirements of § 60.4208 of the final rule, which restricts the installation of engines subject to outdated emission standards. This restriction applies only to the installation of new engines subject to the final rule, and does not apply to the installation of previously used engines.

D. What are the final standards?

1. Overview

The format of the final standard is an output-based emission standard for PM, NO_X, CO, and NMHC in units of emissions mass per unit work performed (grams per kilowatt-hour (g/KW-hr)) and smoke standards as a percentage. The emission standards are generally modeled after EPA's standards for nonroad and marine diesel engines. The nonroad diesel engine standards are phased in over several years and have Tiers with increasing levels of stringency. The engine model year in which the Tiers take effect varies for different size ranges of engines. The Tier 1 standards were phased in for nonroad diesel engines beginning in 1996 to 2000. The Tier 2 nonroad CI standards are phased in starting from 2001 to 2006, and the Tier 3 limits are phased in starting from 2006 to 2008. The Tier 3 limits apply for engines greater than or equal to 50 and less than or equal to 750 horsepower (HP) only. Tier 4 limits for nonroad engines are phased in beginning in 2008.

2. Final Standards for Engine Manufacturers

Engine manufacturers must meet the emission standards of the rule during the useful life of the engine. a. 2007 Model Year and Later Non-Emergency Stationary CI ICE ≤3,000 HP and With a Displacement <10 Liters per Cylinder. The standards require that engine manufacturers certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 3,000 HP and a displacement of less than 10 liters per cylinder to the Tier 2 through Tier 4 nonroad diesel engine standards as shown in table 1 of this preamble, as applicable, for all pollutants, for the same model year and maximum engine power.

TABLE 1.—NO_X, NMHC, CO, AND PM EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR 2007 MODEL YEAR AND LATER NON-EMERGENCY ENGINES ≤3,000 HP AND WITH A DISPLACEMENT <10 LITERS PER CYLINDER AND 2011 MODEL YEAR AND LATER NON-EMERGENCY ENGINES >3,000 HP AND WITH A DISPLACEMENT <10 LITERS PER CYLINDER [a]

Maximum engine power	Model year(s)	NMHC + NO_X	NMHC	NO_X	CO	PM
KW<8 (HP<11)	2007	7.5 (5.6)			8.0 (6.0)	0.80 (0.60)
	2008+					0.40 (0.30)
8≤KW<19	2007				6.6 (4.9)	0.80 (0.60)
(11≤HP<25)	2008+					0.40 (0.30)
19≤KW<37 (25≤HP<50)	2007	7.5 (5.6)			5.5 (4.1)	0.60 (0.45)
	2008–2012					0.30 (0.22)
	2013+	4.7 (3.5)				0.03 (0.02)
37≤KW<56 (50≤HP<75)	2007	7.5 (5.6)			5.0 (3.7)	0.40 (0.30)
	2008–2012	4.7 (3.5)				[a] 0.30 (0.22)
	2013+					0.03 (0.02)
56≤KW<75 (75≤HP<100)	2007	7.5 (5.6)				0.40 (0.30)
	2008–2011	4.7 (3.5)				
	2012–2013		[b] 0.19 (0.14)	[b] 0.40 (0.30)	5.0 (3.7)	0.02 (0.01)
	2014+		0.19 (0.14)	0.40 (0.30)		
75≤KW<130 (100≤HP<175)	2007	4.0 (3.0)				0.30 (0.22)
	2008–2011					
	2012–2013		[b] 0.19 (0.14)	[b] 0.40 (0.30)	5.0 (3.7)	0.02 (0.01)
	2014+		0.19 (0.14)	0.40 (0.30)		
130≤KW<560 (175≤HP<750)	2007–2010	4.0 (3.0)			3.5 (2.6)	0.20 (0.15)
	2011–2013		[b] 0.19 (0.14)	[b] 0.40 (0.30)		0.02 (0.01)
	2014+		0.19 (0.14)	0.40 (0.30)		
KW>560 (HP>750)	2007–2010	6.4 (4.8)			3.5 (2.6)	0.20 (0.15)
Except generator sets	2011–2014		0.40 (0.30)	3.5 (2.6)		0.10 (0.075)
	2015+		0.19 (0.14)	3.5 (2.6)		0.04 (0.03)
Generator sets 560<KW≤900 (750<HP≤1200)	2007–2010	6.4 (4.8)			3.5 (2.6)	0.20 (0.15)
	2011–2014		0.40 (0.30)	3.5 (2.6)		0.10 (0.075)
	2015+		0.19 (0.14)	0.67 (0.50)		0.03 (0.02)
Generator sets KW>900 (HP>1200)	2007–2010	6.4 (4.8)			3.5 (2.6)	0.20 (0.15)
	2011–2014		0.40 (0.30)	0.67 (0.50)		0.10 (0.075)
	2015+		0.19 (0.14)			0.03 (0.02)

[a] A manufacturer has the option of skipping the 0.30 g/KW-hr PM standard for all 37–56 KW (50–75 HP) engines. The 0.03 g/KW-hr standard would then take effect 1 year earlier for all 37–56 KW (50–75 HP) engines, in 2012. The Tier 3 standard (0.40 g/KW-hr) would be in effect until 2012.

[b] 50 percent of the engines produced have to meet the NO_X + NMHC standard, and 50 percent have to meet the separate NO_X and NMHC limits.

b. 2007 Model Year and Later Non-Emergency Stationary CI ICE >3,000 HP and With a Displacement <10 Liters per Cylinder. The standards require that engine manufacturers certify their 2007 through 2010 model year non-

emergency stationary CI ICE with a maximum engine power greater than 3,000 HP and a displacement of less than 10 liters per cylinder to the emission standards shown in table 2 of this preamble. For 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 3,000 HP and a displacement of less than 10 liters per cylinder, manufacturers must certify these engines to the Tier 4 nonroad diesel engine standards as shown in table 1 of this preamble, as applicable, for all pollutants, for the same model year and maximum engine power.

TABLE 2.—NO_X, NMHC, CO, AND PM EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR PRE-2007 MODEL YEAR ENGINES WITH A DISPLACEMENT <10 LITERS PER CYLINDER AND 2007–2010 MODEL YEAR ENGINES >3,000 HP AND WITH A DISPLACEMENT <10 LITERS PER CYLINDER

Maximum engine power	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)	.....	.....	8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)	.....	.....	6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)	.....	.....	5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	.....	.....	9.2 (6.9)	.....	.....
56≤KW<75 (75≤HP<100)	.....	.....	9.2 (6.9)	.....	.....
75≤KW<130 (100≤HP<175)	.....	.....	9.2 (6.9)	.....	.....
130≤KW<225 (175≤HP<300)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

c. 2007 Model Year and Later Non-Emergency Stationary CI ICE with a Displacement ≥10 and <30 Liters per Cylinder. The standards require that engine manufacturers certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power. These emission standards are shown in table 3 of this preamble.

TABLE 3.— NO_X, THC, CO, AND PM EMISSION STANDARDS IN G/KW-HR FOR 2007 MODEL YEAR AND LATER STATIONARY CI ICE WITH A DISPLACEMENT ≥10 AND <30 LITERS PER CYLINDER

Engine size—liters per cylinder, rated power	THC + NO_X	CO	PM
5.0≤displacement<15.0 All Power Levels	7.8	5.0	0.27
15.0≤displacement<20.0 <3,300 KW	8.7	5.0	0.50
15.0≤displacement<20.0 ≥3,300 KW	9.8	5.0	0.50
20.0≤displacement<25.0 All Power Levels	9.8	5.0	0.50
25.0≤displacement<30.0 All Power Levels	11.0	5.0	0.50

d. 2007 Model Year and Later Emergency Stationary CI ICE <30 Liters per Cylinder. The standards require that manufacturers certify their 2007 model year and later emergency stationary CI ICE less than or equal to 3,000 HP and with a displacement of less than 10 liters per cylinder that are not fire pump engines to Tier 2 through Tier 3 nonroad CI engine emission standards, and Tier 4 nonroad CI engine standards that do not require add-on control, according to the nonroad diesel engine schedule. Manufacturers must certify their 2007 through 2010 model year emergency stationary CI ICE greater than 3,000 HP and with a displacement less than 10 liters per cylinder that are not fire pump engines to the emission standards shown in table 2 of this preamble. Manufacturers must certify their 2011 model year and later emergency stationary CI ICE that are greater than 3,000 HP and with a displacement less than 10 liters per cylinder that are not fire pumps to Tier 2 and Tier 3 nonroad CI engine standards, and to Tier 4 nonroad CI engine standards that do not require add-on control. Manufacturers are required to certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8. Manufacturers must certify their post-Tier 1 emergency fire pumps to the emission standards shown in table 4 of this preamble.

3. Final Standards for Owners and Operators

Owners and operators of stationary CI ICE are required to meet the emission standards in the final rule over the entire life of the engine.

a. Stationary CI ICE with a Displacement <30 Liters per Cylinder. Owners and operators that purchase pre-2007 model year stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must meet the emission standards for pre-2007 model year engines, which are shown in table 2 of this preamble. Owners and operators that purchase pre-2007 model year stationary CI ICE with a displacement of greater than or equal to 10 and less than 30 liters per cylinder that are not fire pump engines must meet the emissions standards in 40 CFR 94.8(a)(1). Section 94.8(a)(1) specifies the following NO_X limits: 17.0 g/KW-hr (12.7 g/HP-hr) when the maximum test speed is less than 130 revolutions per minute (rpm); $45.0 \times N^{-0.20}$ when maximum test speed is at least 130 but less than 2000 rpm, where N is the maximum test speed of the engine in rpm; and 9.8 g/KW-hr (7.3 g/HP-hr) when maximum test speed is 2000 rpm or more.

Owners and operators that purchase fire pump engines must meet the emission standards in table 4 to the final rule.

Owners and operators that purchase 2007 model year and later stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines, and post-Tier 1 fire pump engines, must purchase an engine that is certified by the manufacturer according to the provisions of the rule.

b. Stationary CI ICE with a Displacement ≥30 Liters per Cylinder. Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder are required to reduce NO_X emissions by 90 percent or more, or alternatively they must limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to 1.6 g/KW-hr (1.2 g/HP-hr). Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder are also required to reduce PM emissions by 60 percent or more, or alternatively they must limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 grams per KW-hour (0.11 grams per HP-hour).

4. Final Standards for Manufacturers and Owners and Operators of Emergency Stationary Fire Pump Engines

The rule requires that owners and operators of emergency fire pump engines meet the emission standards shown in table 4 of this preamble, for all pollutants, for the same model year and NFPA nameplate engine power. Starting with the model year in which the most stringent standards begin for each HP range, emergency fire pumps must be certified to the emission standards shown in table 4 of this preamble. Emergency fire pump engines between 50 and 600 HP with a rated speed of greater than 2,650 rpm have been given an additional 3 years to meet the most stringent emission standards.

TABLE 4.—NO_X, NMHC, CO, AND PM EMISSION STANDARDS IN G/KW-HR (G/HP-HR) FOR EMERGENCY FIRE PUMP ENGINES

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[a]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[a]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 +[a]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[a]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[a]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008 +	6.4 (4.8)		0.20 (0.15)

[a] Emergency fire pump engines with a rated speed of greater than 2,650 rpm are allowed an additional 3 years to meet these standards.

5. Fuel Requirements

In addition to emission standards, the final rule requires that beginning October 1, 2007, owners and operators of stationary CI ICE that use diesel fuel must only use diesel fuel meeting the requirements of 40 CFR 80.510(a), which requires that diesel fuel have a maximum sulfur content of 500 parts per million (ppm) and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. Beginning October 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder that use diesel fuel must only use diesel fuel meeting the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, which requires that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. The final rule does not contain a standard for SO_2; the use of low sulfur diesel fuel will result in lower emissions of SO_2. EPA does not expect that the lubricity of the ultra low sulfur diesel (ULSD) will be an issue because additives can be added to ULSD to achieve a sufficient lubricity.

Manufacturers of stationary CI ICE with a displacement of 30 liters per cylinder or more indicated that they are able to operate their engines on 500 ppm sulfur fuel, but they do not have any experience operating their engines on 15 ppm sulfur fuel, and they need to perform testing to ensure there are no problems with the lubricity of the ULSD fuel. The use of ULSD is not required for owners and operators of these engines.

The fuel requirements of this rule only apply to engines that are subject to this rule, *i.e.*, those engines that meet the applicability provisions of § 60.4200 of the final rule.

E. What are the requirements for sources that are modified or reconstructed?

The final standards apply to stationary CI ICE that are modified or reconstructed after July 11, 2005. The guidelines for determining whether a source is modified or reconstructed are given in 40 CFR 60.14 and 40 CFR 60.15, respectively. Stationary CI ICE that are modified or reconstructed must meet the emission standards for the model year in which the engine was originally new, not the year the engine was modified or reconstructed. Therefore, a pre-2007 model year engine modified after 2007 must meet the emission standards for pre-2007 model year engines.

F. What are the requirements for demonstrating compliance?

1. Engine Manufacturers

Manufacturers of stationary CI ICE must demonstrate compliance with the final rule by certifying that their 2007 model year and later stationary CI ICE with displacement less than 30 liters per cylinder meet the emission standards in the final rule using the certification procedures in subpart B of 40 CFR part 89, subpart C of 40 CFR part 94, or subpart C of 40 CFR part 1039, as applicable, and must test their engines as specified in those parts. Manufacturers of fire pump engines do not have to certify Tier 1 engines and, for post-Tier 1 engines, may use the optional test cycle provided in table 6 to the final rule. Manufacturers of certified stationary CI ICE that must meet the emission standards of 40 CFR part 1039 must also meet the emission-related warranty requirements of 40 CFR 1039.120; the provisions in 40 CFR 1039.125 and 40 CFR 1039.130, which require the engine manufacturer to provide engine installation and maintenance instructions to buyers; the engine labeling requirements in 40 CFR 1039.135; and the general compliance provisions in 40 CFR part 1068. Manufacturers of certified stationary CI ICE that must meet the emission standards of 40 CFR part 89 or 40 CFR part 94 must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. After the Tier 4 standards take effect, manufacturers of emergency stationary CI ICE that do not meet the standards for non-emergency engines must add to each such emergency engine a permanent label which states that the engine is for emergency use only. Engine manufacturers must also specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

Engine manufacturers that certify an engine family or families to standards under the final rule that are identical to standards applicable under 40 CFR part 89, 40 CFR part 94, or 40 CFR part 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading (ABT) provisions applicable for such engines under those parts.

EPA has used ABT often in the context of the nonroad engine program. The averaging provisions basically allow manufacturers to certify certain engine families to emission levels more stringent than required and to certify other engine families to levels less stringent than required, as long as the average emission levels to which these engine families are certified are at least equal to the appropriate standards. The banking program allows manufacturers to generate credits by certifying engine families to more stringent standards than required in a particular year and to use such credits in later years. The trading provisions allow engine manufacturers to trade credits with other engine manufacturers covered by the same requirements. The ABT provisions include significant restrictions and compliance requirements, including upper limits on the level to which any engine family may certify.

Under the nonroad engine program, the ABT provisions, where applied, are important elements in our determination of the standards of performance that represent "the greatest degree of emission reduction achievable through the application of technology which the Administrator determines will be available for the engines * * * to which the standards apply, giving appropriate consideration to the cost of applying such technology within the period of time available to manufacturers and to noise, energy and safety factors * * *." See CAA section 213(a)(3) and *Natural Resources Defense Council* v. *Thomas*, 805 F.2d 410, 425 (D.C. Cir. 1986) (upholding EPA regulations allowing manufacturers to meet emission standards for heavy-duty engines by averaging among engine families); see also discussions at 69 FR 38996 (June 29, 2004) and 55 FR 30584, 93–99 (July 26, 1990).

Similarly, we believe that these ABT provisions are essential elements in our determination that the final standards reflect best BDT. The flexibility provided by the ABT provisions allows the manufacturer to adjust its compliance for engine families for which coming into compliance with the standards will be particularly difficult or costly, without special delays or exceptions having to be written into the final rule. Emission-credit programs also create an incentive for the early introduction of new technology (for example, to generate credits in early years to create compliance flexibility for later engines), which allows certain engine families to act as trailblazers for new technology. This improves the feasibility of achieving the standards for the entire population of regulated engines. EPA has concluded as a factual matter, as reflected in this final rule, that an ABT program, operated at the level of the manufacturer, represents the best system of emissions reductions, considering all relevant factors.

We believe the ABT provisions are appropriate for this program. The ABT provisions are applicable to engine manufacturers, who manufacture numerous engines for use in all areas of the country, as opposed to the final owner/operators of the units. These standards will apply to hundreds of different engine families that will be used in tens of thousands of different engines. The flexibility provided by the ABT program is an important instrument for manufacturers to use in meeting the stringent standards of this program affecting a large number of engine families.

We are finalizing minor revisions to several existing mobile source regulations to help incorporate several of these provisions.

EPA is requiring that manufacturers of stationary CI ICE that are seeking certificates of conformity be subject to the same fee provisions as those promulgated for comparable land-based and marine nonroad engines in EPA's most recent fees rulemaking (see 69 FR 26222, May 11, 2004) and be required to comply with the fees rule in the same manner as manufacturers already subject to the fees regulations. Because EPA will be providing certificates of conformity to stationary CI ICE manufacturers and, thus is providing a service or thing of value to the manufacturers, the Independent Offices Appropriations Act (31 U.S.C. 9701) authorizes such a fee collection. Having reviewed the recent fees rule for the motor vehicle and engine compliance program, and its associated cost study which examined EPA's incurred cost of compliance services, we believe that the fees provided in that rule are appropriate for the comparable costs of administering the compliance program for the engines associated with this final rule. These engines are subject to the same general compliance regime as land-based nonroad CI engines and, for those with a displacement between 10 and 30 liters per cylinder, marine engines covered by the existing fees rule. We believe fees for each respective request for certification of conformity for stationary CI ICE should have the same fee amount as for those engines.

Under the provisions of the existing fees rule, the initial fees for certification applications received in the 2004 and 2005 calendar years (for example, $1,822 and $826, respectively, for land-based nonroad CI engines and marine engines) are adjusted on an annual basis

based on several factors, including any changes in the number of certificates in the respective fee categories. Thus, the number of certificates that EPA issues for the engines covered by this final rule will be included in the respective fee categories when EPA conducts its annual calculation for the purposes of adjusting fees based on the existing regulatory formula. Please note that the fee amounts for calendar year 2006 have slightly increased from the fee amounts for the 2004 and 2005 calendar year fees. See EPA's Guidance Letter CCD–05–05 at *http://www.epa.gov/otaq/cert/dearmfr/dearmfr.htm*. Finally, EPA believes it appropriate to commence the collection of fees immediately for each certification of conformity request once the final rule becomes effective.

2. Owners and Operators

All engines and control devices must be installed, configured, operated, and maintained according to the specifications and instructions provided by the engine manufacturer. EPA has also included the option for owners and operators to follow procedures developed by the owner or operator that have been approved by the engine manufacturer for cases where site-specific conditions may require changes to the manufacturer's typical guidelines. Other compliance requirements for owners and operators of stationary CI ICE depend on the displacement and model year of the engine. Owners and operators of pre-2007 model year engines with a displacement less than 30 liters per cylinder and Tier 1 fire pump engines can demonstrate compliance by purchasing an engine that is certified to meet the nonroad emission standards for the model year and maximum engine power of the engine. Other information such as performance test results for each pollutant for a test conducted on a similar engine; data from the engine manufacturer; data from the control device vendor; or conducting a performance test can also be used to demonstrate compliance with the emission standards. The records which indicate that the engine is complying with the emission standards of the final rule must be kept on file by the owner or operator of the engine and be available for inspection by the enforcing agency. Engine manufacturers and/or control device vendors may provide such information at the time of sale. Manufacturers that provide such information to their customers may also choose to place a label on the engine that indicates the engine meets the applicable standards for stationary CI ICE under 40 CFR part 60, subpart IIII, as long as the label does not violate or otherwise interfere with other labels or requirements mandated by other regulations. If the owner or operator chooses to conduct a performance test to demonstrate compliance with the final rule, the test must be conducted according to the in-use testing procedures of 40 CFR 1039, subpart F.

Starting with 2007 model year engines with a displacement of less than 30 liters per cylinder, owners and operators of engines that are not fire pump engines are required to demonstrate compliance by purchasing an engine certified to meet the applicable emission standard for the model year and maximum engine power of the engine. Certified fire pump engines will be available between 2008 and 2011, depending on the size of the engine. For 2007 model year and later fire pump engines that are not required to be certified, owners and operators can demonstrate compliance using the procedures specified for pre-2007 model year engines. Beginning with the model years shown in table 3 to the final rule, owners and operators of fire pump engines must purchase certified engines.

If in-use testing is conducted, the owner and operator of engines with a displacement of less than 30 liters per cylinder would be required to meet not-to-exceed (NTE) emission standards instead of the standards in tables 1 and 2 of this preamble. Engines that are complying with the emission standards in 40 CFR part 1039 (Tier 4 standards) must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d) starting when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039. Engines that are complying with the emission standards in 40 CFR 89.112 (Tier 2/3 standards), and engines that are pre-2007 model year engines must meet the NTE standards in Equation 1 of this preamble:

$$NTE = (STD) \times (M) \qquad \text{(Eq. 1)}$$

Where:

NTE = The NTE emission standard for each pollutant.

STD = The certification emission standard specified for each pollutant in table 1 or 2 of this preamble for the same model year and maximum engine power.

M = 1.25

Alternatively, stationary CI ICE that are complying with the emission standards in 40 CFR 89.112 or that are pre-2007 model year engines may use the testing procedures specified for engines with a displacement of greater than or equal to 30 liters per cylinder, described in the next paragraph, instead of the NTE provisions discussed above.

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct an initial performance test to demonstrate compliance with the emissions reductions requirements, establish operating parameters and monitor operating parameters continuously. Non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder must also conduct annual performance tests. The NTE standards do not apply to engines that have a displacement of greater than or equal to 30 liters per cylinder. Testing conducted on these engines must be performed to demonstrate that NO_X and PM emission standards are achieved, and the tests must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

G. What are the monitoring requirements?

Owners and operators of stationary CI ICE that are equipped with catalyzed diesel particulate filters (CDPF) must install a backpressure monitor that will notify the operator when the high backpressure limit of the engine is approached. All emergency stationary CI ICE must have a non-resettable hour meter to track the number of hours operated during any type of operation.

H. What are the reporting and recordkeeping requirements?

The owner or operator of non-emergency stationary CI ICE that are greater than 3,000 HP or with a displacement of greater than or equal to 10 liters per cylinder, and non-emergency stationary CI ICE pre-2007 model year engines greater than 175 HP and not certified, must submit an initial notification. The initial notification must contain information identifying the owner or operator, the engine and control device, and the fuel used. As mentioned, engines that are not certified have various options for demonstrating initial compliance, which would be documented in records available on-site. Also, all owners and operators must keep records of all information necessary to demonstrate compliance with the emission standards such as records of all notifications submitted, any maintenance conducted on the engine, any performance tests conducted on the engine (or performance tests conducted on a similar engine that is used to

demonstrate compliance), engine manufacturer or control device vendor information, *etc.* Owners and operators of certified engines must keep records of documentation from the manufacturer that the engine is certified to meet the emission standards. Owners and operators of engines that are equipped with CDPF must install a backpressure monitor and are required to maintain records of any corrective action taken after the backpressure monitor has notified the owner or operator that the backpressure limit is approached. These records must be available for viewing upon request by the enforcing agency. Owners and operators of emergency engines are not required to submit initial notifications. However, these engines must have a non-resettable hour meter. Owners and operators of emergency engines are required to keep records of their hours of operation. Owners and operators must record the time of operation of the engine and the reason the engine was in operation during that time.

III. Summary of Significant Changes Since Proposal

Most of the rationale used to develop the proposed rule remains the same for the final rule. Therefore, the rationale previously provided in the rule, as proposed, is not repeated in the final rule, and the rationale sections of the rule, as proposed, should be referred to. Changes that have been made to the rule since proposal are discussed in this section with rationale following in the Summary of Responses to Major Comments section.

A. Applicability

The final rule includes an exemption for engines used at test cells/stands.

The final rule also exempts area sources from title V permit requirements.

B. Fuel Requirements

The proposed rule required the same fuel requirements for all engines, except engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands. The final rule does not require owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder subject to the rule that use diesel fuel to meet the 15 ppm fuel sulfur requirements. Owners and operators of these engines are subject to the 500 ppm fuel requirements only, starting October 1, 2007.

In addition, EPA received comments on the proposal requesting that EPA delay the sulfur requirements for diesel fuel intended for stationary ICE in rural areas of Alaska until 2010, consistent with the approach that was expected to be proposed for nonroad and highway engines in rural Alaska. EPA believes it is appropriate to address stationary, highway and nonroad fuel requirements in one rule where all issues can be addressed and resolved. Therefore, on October 13, 2005 (70 FR 59690), EPA proposed to revise the provisions of 40 CFR part 69 (Special Exemptions from the CAA) to delay low sulfur fuel requirements for rural areas of Alaska until December 1, 2010, except that certain engines, including any 2011 model year and later stationary CI engines operating in rural Alaska prior to December 1, 2010, would be required to meet the 15 ppm sulfur requirement for diesel fuel. EPA has included a special section in the final rule that specifies that until December 1, 2010, owners and operators of stationary CI engines located in Alaska should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

In addition, the final regulations include language that allows Alaska to submit for EPA approval through rulemaking process, by no later than January 11, 2008, an alternative plan for implementing the requirements of this regulation for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. The alternative plan must be based on the requirements of section 111 of the CAA including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR Part 60, Subpart IIII.

EPA has included an option in the final rule for owners and operators of pre-2011 model year engines located in remote areas of Alaska to petition the Administrator to use any fuels mixed with used oil that do not meet the fuel requirements in § 60.4207 of the final rule beyond the required fuel deadlines. The owner or operator must show that there is no other place to burn the used oil. Each petition, if approved, is valid for a period of up to 6 months.

EPA has clarified that the fuel requirements in § 60.4207 of the final rule only apply to stationary CI ICE that are subject to the rule, and do not apply to new engines manufactured prior to April 1, 2006, unless they have been modified or reconstructed after July 15, 2005.

C. Maintenance and Testing

The proposed rule limited the use of emergency engines for the purpose of maintenance and testing to 30 hours per year. This limit has been increased in the final rule to 100 hours per year. EPA has also included a provision that allows anyone to petition the Administrator for additional hours, beyond the allowed 100 hours per year, if such additional hours should prove to be necessary for maintenance and testing reasons. EPA will not require a petition for additional hours if the hours beyond 100 hours per year for maintenance and testing purposes are mandated by regulation such as State or local requirements.

D. Emission Standards

The emission standards for engines with a displacement of greater than or equal to 30 liters per cylinder in the final rule are different than in the rule, as proposed. EPA received comments that the proposed PM standards and the proposed NO_x g/KW-hr standard were not achievable. EPA revised the standards for the final rule and believes the final levels are achievable through the use of on-engine controls, aftertreatment, and lower sulfur fuel.

E. Recordkeeping

For emergency engines, EPA proposed that owners and operators record the use of the engine during non-emergency operation. These hours would be recorded through the non-resettable hour meter. Based on comments received on the rule, as proposed, EPA has determined that it is appropriate to require records of all operation, including hours operated during non-emergencies and hours operated during emergencies. The owner must also record the time of operation of the engine and the reason the engine was in operation during that time.

IV. Summary of Responses to Major Comments

A more detailed summary of comments and EPA's responses can be found in the Summary of Public Comments document, which is available from the rulemaking docket (*see* **ADDRESSES** section).

A. Applicability/Effective Date

Comment: One commenter expressed that the 6-month installation date deadlines in § 60.4208 of the proposed rule are problematic and unworkable. The period of time between the manufacture of a stationary CI engine and its installation is regularly in excess of 6 months. The NSPS should incorporate the relevant anti-stockpiling

from the nonroad rule (40 CFR 89.1003(b)(4)) instead.

Another commenter said that § 60.4208(a) of the proposed rule does not exclude fire pumps (emergency CI ICE), but § 60.4208(c) through (f) of the proposed rule does. A 6-month time limitation will become problematic, the commenter said. Due to construction project complexities, size and delays, NFPA certified fire pump engines may not be installed for as long as 1 year after the date of sale by the NFPA certifier. The NFPA certified fire pump engines are typically not purchased for inventory, and therefore, are self regulated by the date of manufacturer. The commenter stated that fire pump engines should be exempt from this fixed time restriction.

Response: EPA agrees with the commenters that the 6-month deadline for installing engines of a previous tier is not long enough to allow for the time that typically elapses between order and installation of an engine and may prevent engine manufacturers from using up existing inventories of engines. Therefore, EPA increased the time limit to 24 months after the beginning of the model year. EPA has also included anti-stockpiling provisions similar to those used for nonroad engines to prohibit stockpiling of previous tier engines in the final rule. Also, EPA was concerned about imports of non-compliant stationary CI engines and has made it clear in § 60.4208 of the final rule that the limitations of that section apply to imports of engines with a displacement of less than 30 liters per cylinder also. Engines with a displacement greater than or equal to 30 liters per cylinder are not included in this provision since compliance with the emission standards for those engines can only be demonstrated through on-site stack testing. Finally, EPA has exempted stationary emergency fire pump engines from the deadlines in § 60.4208(a) and (b) of the final rule to account for the fact that fire pumps have different timing requirements for the emission standards they have to meet.

Comment: One commenter requested that the rule exempt area sources from the requirement to have a title V permit solely because of the presence of an affected engine.

Response: Section 502(a) of the CAA specifies the sources that are required to obtain operating permits under title V. These sources include (1) any affected source subject to the acid deposition provisions of title IV of the CAA, (2) any major source, (3) any source required to have a permit under parts C or D of title I of the CAA, (4) "any other source (including an area source) subject to standards under section 111 (new source performance standards) or 112 (national emissions standards for hazardous air pollutants)," and (5) any other stationary source in a category designated by regulations promulgated by the Administrator.

Section 502(a) of the CAA also provides that the Administrator may "promulgate regulations to exempt one or more source categories (in whole or in part) from the requirements of this subsection if the Administrator finds that compliance with such requirements is impracticable, infeasible, or unnecessarily burdensome on such categories, except that the Administrator may not exempt any major source from such requirements." EPA has exempted many area sources subject to section 111 or 112 standards from title V requirements in prior rulemakings, in particular see a recent final rule, 70 FR 75320, December 19, 2005, that provides additional background information and rationale for such exemptions for a large number of area sources subject to CAA section 112 standards.

In the case of affected stationary CI engines located at area sources, EPA believes compliance with permit requirements under title V would be impracticable, infeasible and unnecessarily burdensome for the reasons explained below.

First, title V permits would be unnecessarily burdensome for area sources subject to this final rule because title V would not result in significant improvements to compliance with the CAA section 111(b) standard for the area sources. (The term "title V permits" used here refers to permits issued under 40 CFR parts 70 or 71 by either a State or local agency or EPA.) For a great number of these area sources, these engines are the only emission source and the owner/operator (often a hospital or a school) will not be at all familiar with the requirements for permits. To demonstrate compliance with these section 111(b) standards, the final rule requires the owner or operator of the area source to purchase a certified stationary CI engine. Certification that the engine meets the emission reduction requirements of this final rule is done by the manufacturer of the engine, rather than the area source that owns or operates the engine. This strategy places a significant amount of responsibility for compliance with the standard on the manufacturer, compared to many other emission standards that place the compliance responsibility on the owner or operator. EPA believes this strategy is the most effective way to ensure that the standard is met during the useful life of the engine. Also, title V would not result in significant improvements to compliance with the standard for these area sources because the section 111(b) standard itself contains adequate compliance requirements for these area sources, consistent with the CAA, without relying on title V.

Second, title V would impose certain burdens and costs on area sources subject to this final rule that EPA does not believe are justified when compared to the potential for title V permits to improve compliance with the CAA section 111(b) standards for such sources. This is so because EPA believes the costs and burdens of title V permits for the typical area sources subject to this final rule would be significant. This assessment is not based on any particular empirical data or study but on a review of the types of stand-alone area sources that would be subject to the final rule, for example, small farming operations using diesel engines for irrigation purposes and small businesses and residential homeowners using diesel engines for back-up electrical power generation. (See current ICR for 40 CFR part 70, EPA ICR # 1587.06 and OMB control number 2060–0243 for EPA's best estimate of the burdens and costs of title V for sources subject to 40 CFR part 70 on a national, aggregate basis.) Also, as explained above, EPA's judgment is that requiring operating permits for these area sources would not result in significant improvements to compliance over that already required by this final rule. Thus, the burdens and cost of title V permits for these area sources would be significant, and in any case, they will be unnecessary and not justified, when compared to the low potential for title V permits to improve compliance, consistent with the "unnecessarily burdensome" criterion of section 502(a) of the CAA.

The strategy of this final rule, requiring the manufacture of cleaner burning emission sources (manufacturer-based controls), has been employed in other CAA section 111 standards, for example, the NSPS for new residential woodstoves (subpart AAA of 40 CFR part 60). We exempted area sources subject to the woodstove NSPS in the final rule for 40 CFR part 70 (57 FR 32250, July 21, 1992) for reasons similar to those we describe today for stationary CI IC engines. (40 CFR 70.3(b)(4) and 40 CFR 71.3(b)(4).)

Thus, we have decided to exempt area sources subject to this final rule from title V operating permit requirements under 40 CFR part 70 and 40 CFR part 71, and we have changed the applicability language in the final regulations to specify this. Under this approach, title V exemptions are

allowed for an area source, provided the area source is not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for another reason, such as when the source becomes a major source. Also note that this exemption only affects whether an area source is required to obtain an operating permit, it has no bearing on any other requirements of this final rule.

B. Modeling Mobile Source Program

Comment: Two commenters stated that the proposed standard layers mobile source requirements with similar 40 CFR part 60 requirements. These mobile legacy provisions, such as the General Provisions and testing requirements for nonroad engines, are foreign to stationary source operators. Two commenters said that a rule modeled after mobile standards is unnecessarily complex and includes requirements that are inconsistent with the legacy of stationary sources affected under 40 CFR part 60. One commenter was concerned that an array of unforeseen implementation issues could arise in translating the mobile source criteria to stationary sources.

One commenter said that the limits are based upon the engine model year and could lead to confusion. Limits for stationary sources have in the past been based upon the date of construction or operation. Two adjacent facilities may install identical engines manufactured by different companies and are of different model years. These engines could be subject to different limits. The facility that is subject to the more stringent limits may challenge the fairness of the limits and the cost to comply with the more stringent limits. This can be avoided by establishing limits based upon the date a source commences operation. The commenter added that compliance with NSPS limits is primarily based upon manufacturer guarantees. This is a new regulatory strategy for stationary sources. The New York (NY) Department of Environmental Conservation (DEC) issues permits to facility owners/operators, which are contracts whereby the permittee agrees to comply with all applicable provisions. Manufacturers are not parties to permits issued by the NY DEC. Any violation of a permit condition is, therefore, the responsibility of the permittee. Any enforcement action initiated by the NY DEC would be against the permittee, not the manufacturer. The NY DEC's distributed generation rule (6 NYCRR part 222) is structured in this way. If an engine is not in compliance with the limits, the owner/operator may have legal recourse against the manufacturer depending upon the conditions of a warranty. The NY DEC, not being a party to a warranty, would not have legal recourse against the manufacturer. This commenter recommended that the owner/operator be responsible for compliance with emission limits under the NSPS.

Response: EPA disagrees with these commenters on certain issues. EPA agrees that aligning the NSPS with mobile standards and placing significant responsibility with manufacturer is somewhat unusual, but it is not an unprecedented regulatory strategy for stationary sources (40 CFR part 60, subpart AAA, Standards of Performance for New Residential Wood Heaters). EPA has determined that it is appropriate to develop a regulatory strategy for internal combustion engines that is generally directed towards engine manufacturers. EPA recognizes that the proposed approach is different than the strategy typically followed in NSPS rulemaking for stationary sources, which is often aimed at the owners and operators of stationary sources. However, EPA has worked with engine manufacturers throughout the rule development process, and it was determined that developing a rule that will affect engines at the manufacturing level, will achieve the best system of emission reduction while taking into account the cost of achieving such reductions. The certification of nonroad diesel engines is a well-established program that engine manufacturers are familiar with. Engine manufacturers have indicated that they often design and manufacture the same engines for nonroad use as for stationary use. As mentioned in the preamble to the proposed rule, the vast majority of stationary CI engines are consumer products produced in mass quantities. Internal combustion engines have traditionally been regulated through the manufacturer for purposes of meeting mobile source regulations. Manufacturers have extensive experience with complying with such standards. It is also simpler, more reliable, and comparatively inexpensive to regulate stationary CI engines employing the same approach as for mobile sources than to create a new approach based on testing by every owner and operator.

Moreover, EPA believes this method of regulation will be much easier for owners and operators (represented by the commenters) than a set of regulations aimed primarily at owners and operators. The commenters note that the proposed standards layer mobile source requirements on 40 CFR part 60 requirements, but EPA's mobile source regulations are directed towards manufacturers, so they will not substantially affect owners and operators. In general, owners and operators will be required to purchase certified engines, which are likely to be the only new engines available, since manufacturers will not be able to sell uncertified engines. This would seem to be preferable from an owner/operator's perspective than having to individually test all of its new engines initially and periodically thereafter to show compliance with the standards, and to engage in all of the other compliance procedures normally required for stationary sources. While EPA acknowledges that this approach is one with which stationary source owners and operators may not be accustomed, EPA believes that this approach will provide less burden to owners and operators than a more standard NSPS approach. Regarding the comments from NY DEC, EPA believes that because the owner/operator will be purchasing certified engines, it will know prior to purchase and installation the emission limits and costs for the engine. A manufacturer would not be selling identical engines for different model years unless the engine met the standards for both model years, so there would be no increased cost for the user. Unlike in other regulations, the emission-related costs are known from the outset, because they are inherent in the cost of the certified engine. The NSPS should have no effect on the manner in which NY DEC ensures compliance with its distributed generation rule. However, as discussed below, owners and operators do have responsibilities under the NSPS, compliance with which can be readily determined. EPA agrees that it would be appropriate to specify what parts of the General Provisions apply to engines subject to subpart IIII of 40 CFR part 60. In the final rule, EPA has included a table listing which General Provisions from 40 CFR part 60, subpart A, apply to stationary CI engines subject to this subpart.

C. Fuel Requirements

Comment: One commenter stated that no operating experience currently exists for engines with a displacement of greater than or equal to 30 liters per cylinder with 15 ppm sulfur fuel, and therefore, an alternative should be worked out. The use of ULSD may have impacts on safety, reliability and durability of the stationary engine. At the current stage of technology, engine manufacturers will not be able to guarantee an engine operating

exclusively on ULSD. According to the European Union (EU) Directive 1999/32/EC, the maximum sulfur content of heavy fuel oil is a maximum of 1 weight percent (10,000 ppm) from January 1, 2003, and in gas oil a maximum of 0.1 weight percent (1,000 ppm) from January 1, 2008. These fuels can be used in stationary CI engine plants without installed flue-gas desulfurization. According to the EU 2001/80/EC Directive, a maximum of 0.5 weight percent sulfur (850 milligrams per Normal (273.15 °Kelvin, 101.3 kilo Pascal (kPa)) cubic meters (mg/Nm^3) SO_2 at 3 percent oxygen (O_2) and 280 mg/Nm^3 SO_2 at 15 percent O_2 fuel oil can be used in 50 to 100 megawatt (MW) boiler plants. Large CI engines are designed to operate on heavy fuel oil and the use of ultra clean light fuel oils (with different density, viscosity, etc., properties) may cause operation problems. The commenter requested that for large engines the requirement should be equivalent to 500 ppm after 2010 on the U.S. mainland. The commenter also stated it was reasonable for EPA to exempt Guam, American Samoa and the Commonwealth of the Northern Mariana Islands from fuel limits.

Another commenter expressed that additional time may be necessary to phase in the use of ULSD with respect to new engines with a displacement of 30 liters per cylinder or greater.

Response: EPA requested comments on whether ownes and operators of stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder should be required to use ULSD fuel. There is no information regarding the effect of burning 15 ppm sulfur fuel in stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder and operators of these engines have expressed concerns with burning such fuel. Manufacturers of engines with high displacement have told EPA that there is a large variety of fuels used in these engines and that the fuel used can contain a high sulfur content. The fuels used in large displacement engines are of a different grade than the fuels used in nonroad engines. Information EPA has received indicates that engines with a displacement of greater than or equal to 30 liters per cylinder are often designed to operate on residual fuels containing up to 5 percent sulfur, but that these engines can also operate on fuels with lower fuel content. Further information on this subject can be found in the docket (EPA–HQ–OAR–2005–0029–0146). EPA believes it would be inappropriate to require owners and operators of these engines to use ULSD as the impacts of using such fuel are unknown. However, EPA does believe it is appropriate to require these engines to utilize fuel containing 500 ppm sulfur or less, consistent with the commenter's statement. The final rule has been written to require owners and operators of stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder to use 500 ppm sulfur fuel starting October 1, 2007. Owners and operators of stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder are not required to use 15 ppm sulfur fuel, but must use 500 ppm fuel from October 1, 2007, and beyond.

Comment: One commenter expressed that the proposed fuel requirements would be burdensome to some facilities that store and use large inventories of diesel fuel. To comply with the proposed fuel requirements, an owner or operator of stationary CI engines with large fuel inventories may have to dilute/blend existing diesel fuel inventories with fuel that is virtually sulfur-free prior to each compliance date in § 60.4207 of the proposed rule, and sample/analyze the blended fuel for sulfur content, and cetane index or aromatic content to document compliance with the fuel content requirements. Sources with large fuel inventories may require dilution quantities that exceed the existing storage tank capacities, and diluting/blending would be an expensive task. Diluting/blending fuel to meet these requirements would require the procurement of diesel fuel that has a sulfur content and cetane index or aromatic content that would be much more stringent than the specified fuel sulfur content standards. As an alternative, owners/operators would have to deplete existing diesel fuel inventories completely prior to each compliance date and then purchase fuel that meets the requirements of 40 CFR 80.510(a) and (b) for just-in-time fuel delivery prior to each compliance date. This alternative is not reasonable for owners/operators that operate 24 hours a day. Also, depleting inventories to zero potentially would cause owners/operators to have to clean/remove tank bottoms to prevent fouling of fuel lines and equipment, and to have to dispose of off-specification diesel fuel, producing additional costs. The commenter requested that EPA include a grandfather clause that would allow owners/operators to continue to use up existing fuel inventories after October 1, 2007, and October 1, 2010. Alternatively, EPA could revise § 60.4207(a) and (b) of the proposed rule by replacing the word "use" with "purchase."

Response: EPA believes it is providing sufficient time for owners and operators to switch to using lower sulfur fuel. Substantial amounts of fuel meeting the fuel requirements will be available in the years and months prior to implementation of the fuel requirements. However, EPA understands that there may be cases where sources may be unable to use up existing non-compliant fuel inventories prior to the fuel compliance dates of the rule. EPA does not think it would be appropriate to include an open-ended provision allowing owners and operators to use up existing non-compliant fuel inventories after October 1, 2007 and October 1, 2010. Also, EPA does not believe it would be appropriate to use the word "purchase" instead of "use" in § 60.4207 of the rule. A more reasonable provision, which takes into account that there may be varying volumes of existing fuels from site to site, would be for the owners and operators to petition the Administrator for additional time beyond the schedule set in the final rule to use up existing non-compliant fuels. EPA believes that a case-by-case approach to dealing with existing fuel inventories is more appropriate and will incorporate the uniqueness of each source's fuel inventory situation. EPA has incorporated a provision into the final rule that allows owners and operators that have stationary CI engines subject to the rule to petition the Administrator for additional time to use up existing fuel inventories. If approved, the petition is valid for a period of up to 6 months. If additional time is needed beyond that, the owner or operator would have to submit another petition to the Administrator. Also, EPA does not believe such a provision should be included for engines built after 2011 as these stationary CI engines will require the use of ULSD in order to operate properly. Therefore, the final rule includes the provision to petition the Administrator to use up existing non-compliant fuel for a period of 6 months only for pre-2011 model year stationary CI engines.

D. Maintenance and Testing

Comment: Several commenters said that the testing and maintenance allowance for emergency engines in the proposed rule was not sufficient. Many commenters recommended revising the definition of emergency engines to be consistent with 40 CFR part 63, subpart ZZZZ, for stationary RICE. Commenters recommended various maintenance and testing allowances. One commenter

recommended a minimum of 8 hours per month or 96 hours per year. One commenter encouraged EPA to either exempt hospitals, categorically from the restrictions, or apply a reasonable allowance of combined total operations of all emergency generators per hospital facility to 2,000 hours per year. Four commenters recommended that EPA specify 100 hours per year instead, as a maximum for maintenance and readiness testing. Some commenters recommended that regulatory agencies could establish site-specific limits for maintenance checks and readiness testing. One commenter recommended allowing hospitals to petition for an exemption raising the limit beyond 100 hours as a permanent exemption or a one-time exemption. One commenter recommended limiting maintenance and testing activities to 78 hours per year. One commenter said that the operation of an emergency engine should be at the discretion of the owner or operator, based on the engine manufacturer's recommendations and any applicable health and safety codes. The commenter believed this requirement is unnecessary because non-emergency engines will be allowed to operate without any hourly limitations.

Response: As summarized above and in more detail in the Summary of Public Comments document, EPA received several comments on the issue of maintenance and testing of stationary emergency engines. EPA proposed to limit the time emergency engines spend during maintenance and testing to 30 hours per year, based on information available at the time of proposal indicating that 30 hours per year would be sufficient to address operation for such activities. For example, NFPA requirements stipulated 30 minutes per week (27 hours per year) for maintenance and testing purposes to ensure that the engine would respond properly in the event of an emergency. A survey conducted by the California (CA) Air Resources Board (ARB) indicated that emergency engines spend on average of about 30 hours per year for all operation. The proposed limit of 30 hours per year for maintenance and testing for stationary emergency CI engines was also consistent with the CA Airborne Toxic Control Measure (ATCM). Since the proposal of the rule, CA increased the maintenance and testing limit based on new information it had received, which indicated that more frequent testing was required by certain healthcare regulatory bodies. Local air districts in CA are allowed to approve additional hours of operation for maintenance and testing beyond 30 hours per year, and the ATCM also includes a sliding scale based on the PM levels the engine emits, of up to 100 hours per year. Considering the extent to which commenters provided information indicating that the proposed 30 hours per year allowance was not sufficient for most emergency engines, EPA has determined that it is appropriate to allow emergency engines to operate 100 hours per year during maintenance and testing. It is crucial to allow owners and operators of emergency engines to sufficiently test and maintain their emergency engines to ensure the engines will respond properly and as expected during an emergency situation. The engines must respond without failure and without lengthy periods of startup and adequate testing and maintenance must therefore be performed. Based on the comments received, EPA believes that 100 hours per year is a sufficient amount to ensure readiness of emergency engines in most cases. The final rule has been written to limit operation of emergency engines to 100 hours per year during maintenance and testing operation. In addition, EPA believes that there may be cases where it is necessary for an owner or operator of emergency engines to operate their emergency engines beyond 100 hours per year to ensure their engines will respond as needed during an emergency. Additionally, Federal, State or local safety standards may require maintenance and testing beyond 100 hours per year. Therefore, EPA has incorporated a provision into the final rule that allows owners and operators to petition the Administrator for approval to operate their emergency engines for more than 100 hours per year for maintenance and testing purposes. If a sufficient case is presented, the Administrator may approve such petitions for additional time to conduct maintenance checks and readiness testing to ensure that emergency engines can be used for their intended application during emergency situations. A petition is not required if an owner or operator can show that operation beyond 100 hours is required by regulation such as State or local requirements. EPA does not believe it is generally appropriate to allow unlimited hours for maintenance and testing, or hours well in excess of 100 hours, as suggested by some commenters, given the substantial emissions that can occur from these engines during their operation and the ability of owners and operators to meet their maintenance and testing needs under the final provisions. The California ARB presented in Table IV–1 of their Staff Report from 2003 that PM and NO_X emissions from emergency standby engines in 2002 were 0.3 and 6.4 tons per day, respectively. The maintenance and testing allowance in the final rule would include training for and simulation of emergency situations and EPA believes the 100 hours per year would be sufficient to account for such operation. Documented engine repair would also be considered maintenance and testing and the change from 30 to 100 hours per year should provide enough hours to make necessary repairs. Finally, peak shaving is not considered emergency use and EPA has clarified this in the definition of emergency engine in the final rule.

E. Emission Standards

Comment: One commenter stated that as was the case with the nonroad engines from which stationary CI engines are derived, it remains the case that less stringent standards are necessary for non-generator engines greater than 750 HP.

One commenter said that EPA should set stringent NO_X emissions standards for all engines greater than 750 HP that are based on the use of add-on control technologies. The commenter estimated that stationary diesel engines greater than 750 HP make up about 20 percent of the total stationary engine population, but account for more than half the total emissions of NO_X. The commenter has seen enough successful examples of the use of selective catalytic reduction (SCR) to control NO_X emissions from stationary engines to conclude that EPA should base its NO_X emissions standards for these engines on the use of add-on controls. EPA describes in docket information that SCR has been successfully installed in several applications based on State and vendor information. Several additional add-on NO_X controls that are under development are described in the docket as well; NO_X adsorbers, ozone injection and lean NO_X catalysts. While these technologies are not commercially available yet, they could become viable options within the timeframe of these standards. The commenter believed the current use of SCR and the other available options for add-on NO_X control support the more stringent standards. The commenter is not aware of any special issues with add-on controls on non-generator stationary engines. The commenter believed the issues would be no different than those associated with stationary generator sets and, therefore, saw no reason to set more lenient standards.

One commenter believed that NO_X standards for non-generator, stationary engines with HP ratings of greater than

750 should be equivalent to NO_X standards proposed for generators. Selective catalytic reduction systems have already been installed on stationary engines in this size range and can provide high efficiency NO_X reductions in a cost effective manner. The commenter believed that installation issues with SCR on non-generator engines are no different than those associated with generator engines.

One commenter strongly urged EPA to set aftertreatment forcing NO_X standards for all non-emergency engines with a displacement of less than 10 liters per cylinder and greater than 750 HP. The rationale for setting less stringent standards for nonroad engines other than generator sets were concerns about designing NO_X adsorbers for the space constraints and physical stresses associated with mobile heavy equipment. These conditions do not apply to stationary engines. In the July 2004 nonroad rulemaking, EPA noted the use of SCR on stationary engines as a rationale for aftertreatment forcing NO_X standards for mobile generator set engines.

Regarding EPA's request for comments on whether the generator standards for NO_X should be applied for non-emergency engines greater than 750 HP, one commenter believed that the non-emergency generator engines should be limited to the same levels of emissions as other available ways to generate electricity from fossil fuel. The commenter recommended that limits for engines greater than 750 HP be as stringent as limits for non-emergency engines in sizes between 75 HP and 750 HP, because the larger engines should be able to achieve the same limit as smaller engines, and there is sufficient time to transfer technology to engines greater than 750 HP. If a large engine cannot achieve comparable emission levels, then cleaner equipment, such as turbines, should be used.

Two commenters made the comment that the requirement for add-on controls for engines above 750 HP with a displacement below 10 liters per cylinder should apply solely to continuously operating non-emergency generators.

Response: EPA proposed emission standards for non-emergency non-generators above 750 HP that were not based on the use of add-on controls for NO_X and were less stringent than the proposed standards for generator sets above 750 HP. These standards were consistent with nonroad standards for the same size engines. EPA solicited comments on this issue in the preamble to the proposed rule and received the comments as summarized above. Based on available information and comments received on this issue, EPA still believes it is appropriate to distinguish between non-generators and generators when finalizing standards for non-emergency stationary CI engines above 750 HP. EPA did not receive any specific information or data demonstrating that the standards applicable to generator sets are feasible for engines above 750 HP that are not generator sets. Engine manufacturers have repeatedly expressed that less stringent standards are necessary for non-generator set engines greater than 750 HP. Engine manufacturers have also repeatedly expressed the need to have standards for stationary engines that are consistent with the standards for nonroad engines. No change has been made to the final rule, which includes, as proposed, emission standards consistent with nonroad standards. The standards distinguish between non-generator sets and generator sets, and require less stringent levels for non-emergency engines that are not generator sets, based on improved combustion systems and engine-based NO_X control technologies. (It should be noted that the PM standards for engines above 750 HP, both for generators and non-generators, will likely require particulate traps.)

Comment: As summarized in more detail in the Summary of Public Comments document, EPA received several comments on the proposed standards for engines with a displacement of greater than or equal to 30 liters per cylinder. One commenter said that the NO_X standards for these engines would incur significant costs for the owner and operator, and for emergency engines make it impossible to operate the unit reliably when actually needed. The cost of installing and maintaining an SCR system for large CI engines is outrageously high, especially for applications in Alaska, according to the commenter. These control systems are only marginally cost effective for Alaska units that are meant to be operated continuously. The cost of SCR controls for emergency units outweighs the benefit of having large reliable emergency power available. A recent prevention of significant deterioration project rejected SCR due to high costs. Selective catalytic reduction subsystems must be kept instantly ready over a long period of time in standby mode. One important aspect is having the urea/water mixture heated to prevent freeze up during extremely low temperatures. The system is not simple and operators/mechanics have to be well trained. In most areas of Alaska, such skilled labor is not available. Unless such large units are simple to maintain/operate, they will quickly fall into disrepair or become unusable in an emergency. For emergency engines, the technology that is proven to have the highest reliability while in standby mode should be used. Fuel Injection Timing Retard (FITR) is the technology. It reduces NO_X by 15 to 20 percent, and has been demonstrated as the most cost effective for arctic conditions. FITR technology should also be allowed for engines with a displacement of greater than 10 liters per cylinder unless/until manufacturers establish a proven record of reliable readiness from cold start conditions. This may require delay of emission control requirements for an additional 3 years beyond current implementation dates.

This commenter also said that the PM limits in the proposed rule for engines with a displacement of greater than or equal to 30 liters per cylinder are unrealistic, and there are no current control technologies that are "available" to meet these standards. There have been no applications of electrostatic precipitators (ESP) to stationary sources in the U.S. to date (based on RACT/BACT/LAER Clearinghouse, September 1, 2005). A currently available technology, particulate filter traps, is suited to these large units, although PM removal is less than 60 percent. The commenter noted that PM emissions will already be reduced considerably by the use of low sulfur diesel (LSD) and ULSD. When the reduction from using low sulfur fuel is considered, an additional 50 percent overall reduction from particulate trap technology will meet EPA's goal of reducing PM emissions nationwide. Requiring the use of ESP for emergency units undermines unit reliability and would increase unit size. Approximately 10 percent of the power generated by an emergency CI ICE would be used solely to power an ESP. This would cause all such emergency units to be resized at an increased capacity. The commenter recommended a 50 percent PM reduction or an emission limit of 0.15 g/KW-hr (0.113 g/HP-hr).

Another commenter provided several comments on the proposed standards for engines with high displacement. The commenter stated that environmental impacts and cost effects have not been evaluated and efficient add-on abatement techniques (SCR for NO_X, etc.) will always be needed as a result of the proposal. Only a small number of large CI ICE are sold per year to the U.S. and, therefore, one can forecast that the environmental impact of these engines with respect to the total emissions in the

U.S. is small. The commenter said that in the U.S. territories there are several of these engines, e.g., in Puerto Rico there is a 20 MW electric (MWe) plant and in Guam there is an 80 MWe plant. The proposed limits will raise the electricity produced in these power plants considerably. This might have impacts on the small governmental jurisdiction area flexibility and have significant adverse affect on the supply of energy. This would be in contradiction to the Regulatory Flexibility Act and Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution or Use. The commenter said that the proposed NO_X limit of 0.4 g/KW-hr (0.30 g/HP-hr) equates to about 50 mg/Nm^3 (at 15 percent oxygen (O_2)) and is very strict. This limit is much stricter than World Bank Guidelines or the United Kingdom (UK) limits as referred to in the proposed text. The World Bank NO_X limit for non degraded air-sheds is 2,000 milligram per normal cubic meter (mg/Nm^3) and in degraded air-sheds 400 mg/Nm^3 (at 15 percent O_2) (about 3.1 g/KW-hr). In the UK, the NO_X limits are: 1,300/1,400 mg/Nm^3 (at 15 percent O_2) (about 10.1/10.9 g/KW-hr) (light fuel/heavy fuel oils) for plants less than 50 MW and 200–300 mg/Nm^3 (at 15 percent O_2) (about 1.6–2.3 g/KW-hr) for oil fired plants greater than 50 MW. Extensive research and development work with NO_X emissions from large liquid fired CI ICE has reduced emissions remarkably by primary measures (typically 30 to 35 percent) during the last decade. Primary methods are low NO_X combustion focusing on optimizing: Closing timing of inlet valve, design of fuel injection equipment on the engine, new camshaft, etc. The proposed limit means in practice that SCR is always needed. Selective catalytic reduction needs a reagent aqueous urea/ammonia or pure ammonia to work, and lack of the reagent delivery infrastructure in certain areas will make the proper use of SCR impossible. In order to give industry an incentive to develop new cost-effective primary methods and to continue the positive development in the past decade, the proposed limit should be more realistic based on the zoning approach (attainment/non-attainment area, mainland U.S./other areas). This commenter made some recommendations for acceptable NO_X and PM emission limits, which can be found in the Summary of Public Comments document. The commenter stated that the proposed PM limit of 0.12 g/KW-hr (0.09 g/HP-hr) equals about 16 mg/Nm^3 (at 15 percent O_2). This is a very strict limit, much stricter than the British and World Bank limits, which are 50 mg/Nm^3 (at 15 percent O_2) (about 0.38 g/KW-hr) for large CI plants and 100 mg/Nm^3 (at 15 percent O_2) (about 0.75 g/KW-hr) for smaller CI plants. The ESP is bulky and has a high investment cost. In the Integrated Pollution Prevention and Control Reference Document on Best Available Techniques for Large Combustion Power Plants (BREF) document for large combustion installations, it states that "Due to the different temperature and oxygen content of the diesel flue-gas, the electrical properties of the diesel particulates (e.g., resistivity, etc.,) are different compared to particulates from a boiler flue-gas, and proper testing of the ESP (electrical precipitator) is needed to commercial release." Only a few CI plants are equipped with ESP, and the technical availability of ESP needs to be evaluated case-by-case. In the European Integrated Pollution Prevention and Control, the best available technique is considered to be the use of low ash and low sulfur fuel. Particulate matter limits range from 30 to 50 mg/Nm^3 (at 15 percent O_2) (about 0.23 to 0.38 g/KW-hr) depending on whether heavy or light fuel oil is used. The commenter recommended PM limits in line with the EU BREF document for large CI ICE plant stations (greater than 50 MW). For smaller CI ICE plants, the commenter recommended a PM limit according to the UK approach.

One commenter said that EPA must require stringent PM emissions limits for engines with a displacement of greater than or equal to 30 liters per cylinder. Particulate matter emissions from stationary diesel engines are associated with extremely serious health impacts, including premature mortality and cancer. It would be clearly arbitrary and capricious for EPA to exempt the very largest engines, which it recognizes as operating for thousands of hours per year, from protective control requirements for PM emissions. EPA is correct in its assessment that the cost of SCR to reduce NO_X emissions from these engines is justified because they are so large and because the cost of SCR would be manageable in comparison to the cost of the engines themselves. Similarly, the size of these engines and the hazard posed by their emissions compels EPA to require them to achieve PM reductions that are at least as protective, if not greater than, those for smaller engines. EPA's proposal for these very large engines fails to meet the most basic requirement of section 111 of the CAA, that stringent emissions standards be applied to all sources within the designated category. There is no evidence that a thorough technical analysis of cost or feasibility was performed for these large engines. EPA does not explain why particulate filters could not be developed to apply to these engines. Nor does it explain why ESP, the technology on which the 60 percent control requirement is based, could not be designed to work as effectively in this application as they are known to do in many others, and achieve reductions far in excess of 60 percent. The commenter urged EPA to remedy this deficiency in the final rule by promulgating more stringent control requirements for this class of very large, very highly polluting engines.

Response: EPA does not agree with the commenter that SCR control systems are not a feasible option for engines located in Alaska. There are at least three facilities in Alaska that have stationary engines equipped with SCR, see the memorandum entitled "Emission Standards for Engines with a Displacement of ≥30 Liters per Cylinder," available from the rulemaking docket. EPA does not expect that there will be any emergency engines with a displacement greater than 30 liters per cylinder; however, to the extent that such units exist, they will be very substantial emitters during use and should be required to use the best technology available. In response to the commenter's statement regarding readiness testing, EPA has increased the maintenance and testing allowance for emergency engines from 30 to 100 hours per year in the final rule, with the option to submit a petition for additional hours. EPA agrees in general with the comments regarding the proposed emission limitation for PM. The final rule has been written considering the comments received and requires 60 percent PM reduction or an emission limit of 0.15 g/KW-hr (0.11 g/HP-hr). EPA believes the PM standard will be achievable through the use of lower sulfur fuel, on-engine controls, and aftertreatment. EPA believes that the PM percent reduction requirement is feasible through application of ESP. Based on information EPA has received, the technology is capable of reducing PM by 60 percent. Other information indicates that the technology could reduce PM by even more; from 55 to 85 percent when operating on heavy fuel oil, see information in the docket.

EPA does not agree with the commenter that EPA did not evaluate costs and environmental impacts. EPA has provided detailed analyses of the expected costs of this regulation and the expected emission reductions and benefits and evaluated the technology

for this rule based on best demonstrated technology, not lowest achievable emission rate. EPA evaluated the environmental and economic impacts of the best demonstrated control technologies, which are documented in a memorandum included in the docket entitled "Emission Standards for Engines with a Displacement of ≥30 Liters per Cylinder." While there are few CI ICE with a displacement of greater than or equal to 30 liters per cylinder, they are individually very large emitters of pollutants. Moreover, in regulating criteria pollutants such as ozone and PM, it is assumed that the emissions come from numerous different sources whose individual contribution may be relatively small. Further, as noted in the analyses, there are benefits from these standards in attainment areas, and these national regulations are designed to provide protection from pollution occurring in all areas of the country, not merely nonattainment areas. EPA does not believe that the final emission standards will have a significant adverse effect on the price of electricity and the supply of energy, and the commenters did not provide any data to support this assertion. While EPA disagrees with much of the commenter's statements, EPA has evaluated all comments received on this matter and agrees with the comments that the proposed NO_X g/KW-hr emission limitation and the proposed PM emission standards were too stringent. The final rule requires engines with a displacement greater than 30 liters per cylinder to reduce NO_X emissions by at least 90 percent or meet a NO_X emission limitation of 1.6 g/KW-hr (1.2 g/HP-hr), and to reduce PM emissions by at least 60 percent or meet a PM emission limitation of 0.15 g/KW-hr (0.11 g/HP-hr). There are several facilities worldwide that are successfully using ESP for PM control and specific examples of such installations can be found in the Summary of Public Comments document. Sources can also use other approaches, including traps, the use of lower sulfur fuel, and on-engine controls. The PM emission limit is consistent with comments received from one of the commenters. Regarding the NO_X standard, SCR has been demonstrated as feasible for stationary CI ICE and is in use on several engines in the U.S. SCR technology is capable of achieving emission reductions of 90 percent or greater in many cases. EPA reviewed emission rates of stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder and based on an average uncontrolled NO_X emission rate from these engines of about 11.8 g/HP-hr, applying SCR with a reduction efficiency of 90 percent yields a controlled NO_X emission rate of 1.2 g/HP-hr. EPA therefore believes the final standards for NO_X are appropriate. Also note, that the commenter seems to concede that these standards are feasible, because the commenter accepts the proposed (more stringent) standards in nonattainment areas. EPA notes that this regulation applies only to new engines, not existing engines. The only engines manufactured prior to April 1, 2006, covered by this regulation are engines that are modified or reconstructed, as is required under the CAA. For further discussion regarding EPA's final standards for engines with a displacement greater than 30 liters per cylinder, see the memorandum entitled "Emission Standards for Engines with a Displacement of ≥30 Liters per Cylinder."

F. Military Training Engines

Comment: One commenter recommended that the rule exempt engines used in training and testing of military personnel in the operation, maintenance and repair of engines. These engines may have to be configured similarly to engines used by the U.S. or its allies in combat operations, which may make it difficult or impossible for them to comply with the NSPS.

Response: EPA agrees that it is appropriate to exempt engines used for military purposes. A national security exemption exists already (see, e.g., 40 CFR part 89 subpart J). Engines meeting the conditions specified in 40 CFR 89.908, and the corresponding provisions in parts 94 and 1068, will be considered exempt from the regulations for stationary CI ICE. An engine that receives the national security exemption under the non-road engine provisions when purchased will continue to be exempt if used as a stationary ICE, as long as it continues to be used for national security purposes. In addition, engines that receive a national security exemption will also be exempt from the fuel requirements in section 60.4207 of the final regulations. EPA believes that these provisions address the commenter's concerns.

V. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

The final rule will reduce NO_X emissions from stationary CI ICE by an estimated 38,000 tpy, PM emissions by about 3,000 tpy, non-methane hydrocarbon (NMHC) emissions by about 600 tpy, SO_2 emissions by an estimated 9,000 tpy, and CO emissions by approximately 18,000 tpy in the year 2015. Reductions are presented for the year 2015 because it is the model year for which certified stationary CI ICE would have to meet the final Tier 4 emission standards. EPA estimates that approximately 81,500 stationary CI ICE will be affected by the final rule in the year 2015. Of these, EPA estimates that 20 percent are used in non-emergency applications. EPA expects very few stationary CI ICE with a displacement of 30 liters per cylinder or more to be installed per year, and no emissions or emissions reductions have been estimated for these engines. A secondary impact of the final rule is the reduction of HAP that will result from the use of CDPF. EPA estimates that emissions of HAP will be reduced by approximately 93 tons in the year 2015.

The final rule will reduce NO_X emissions from stationary CI ICE by an estimated 270,000 tpy, PM emissions by about 17,000 tpy, NMHC emissions by about 8,000 tpy, SO_2 emissions by an estimated 24,000 tpy, and CO emissions by approximately 95,000 tpy in the year 2030. EPA estimated emissions reductions for the year 2030 because it is expected that almost all of the air quality impacts will be incorporated by that year, given turnover of old engines.

B. What are the cost impacts?

The total costs of the final rule are mostly based on the cost associated with purchasing and installing NO_X adsorber and CDPF controls on non-emergency stationary CI ICE. A smaller portion of the total costs are attributed to the cost of reporting and the cost for performance testing for a portion of the pre-2007 model year engines. The cost of NO_X adsorber and CDPF were based on information developed for the nonroad rule for diesel engines. EPA expects that very few stationary CI ICE with a displacement of 30 cylinders or more would be installed in the U.S. and, therefore, no costs have been estimated. However, if stationary CI ICE of such displacement are installed, there would be associated notification and compliance testing costs. Further information on how EPA estimated the total costs of the final rule can be found in a memorandum included in the docket (Docket ID. No. EPA–HQ–OAR–2005–0029).

The total national capital cost for the final rule is estimated to be approximately $67 million in the year 2015, with a total national annual cost of $57 million in the year 2015. The year 2015 is the model year for which all stationary CI ICE would have to meet

the final Tier 4 emission standards. The total national capital and annual costs in the year 2030 are estimated to be $93 and $286 million, respectively.

C. What are the economic impacts?

The final rule affects new sources of stationary diesel engines as part of generator sets and welding equipment, pump and compressor equipment, and irrigation equipment. We performed an economic impact analysis, whose methodology is based on that for the nonroad diesel engine rule promulgated by EPA in 2004 that estimates changes in prices and output for affected sources using the annual compliance costs estimated for the final rule. All estimates are for year 2015, since this is the year for which the compliance cost impacts are estimated.

The increases in price estimated for this equipment are the following: 2.3 percent—irrigation systems, 4.3 percent—pumps and compressors, and 10.0 percent—generator sets and welding equipment. While these price increases appear substantial, the corresponding reductions in output are quite small. They are: 0.01 percent—irrigation systems, 0.03 percent—pumps and compressors, and 0.42 percent—generator sets and welding equipment. The price increases and reductions in output were larger for smaller sized engines when compared to larger sized ones. These small reductions in output are due to limited change in demand from consumers in response to the estimated price changes as based on market data utilized in the nonroad rule economic impact analysis. The overall total annual social costs, which reflect changes in consumer and producer behavior in response to the compliance costs, are $39.1 million (2002$) or almost identical to the compliance costs.

The economic impacts are relatively small since the change in expected output from affected industries will be quite small. Thus, the industries producing the affected engines and the consumers who would use these engines will experience little or no impact as a result of the final rule.

For more information, refer to the economic impact analysis report that is in the public docket.

D. What are the non-air health, environmental and energy impacts.

EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of the final rule.

E. What are the benefits?

We estimate the benefits of this rule to be $1.36 billion (2000$) in the year 2015. We base this estimate on the approach and methodology laid out in EPA's 2004 benefits analysis supporting the regulation of emissions from nonroad diesel engines (included in the Final Regulatory Impact Analysis (RIA): Control of Emissions from Nonroad Diesel Engines, May 2004). We chose this analysis as the basis since most of the elements in that rule are similar to those covered here. The engine type, the controls applied, and the pollutants affected are similar to those covered by the Nonroad Diesel engine rule. In addition, EPA believes that these types of engines are broadly distributed across the country similar in distribution to nonroad diesel engines. These four factors lead us to believe is appropriate to use the benefits transfer approach and values in the Nonroad Diesel engine rule analysis for estimating the benefits of this rule. Specifically, these estimates are based on application of the benefits scaling approach derived from the benefits analyses completed for that rulemaking. The methodology is laid out in the Nonroad Diesel RIA.

For this RIA, we did not go through the detailed uncertainty assessment used in the Nonroad Diesel RIA because we lack the necessary air quality input data to run the benefits model. However, the results of a Monte Carlo analysis of the health and welfare benefits presented in Appendix B of the Nonroad Diesel RIA can provide some evidence of the uncertainty surrounding the benefits results presented in this analysis. At the 5th percentile, the monetized benefits are roughly one quarter of the mean benefits estimate and at the 95th percentile they are roughly double the mean. We also used an approach for estimating benefits in which we applied an expert elicitation approach. An expert elicitation approach uses a probabilistic approach that provides quantitative measures of uncertainty from multiple sources as integrated by experts. For the expert elicitation based approach, the 95th percentile of total benefits is approximately three times the mean, while the 5th percentile is approximately one-twentieth of the mean. The overall range from 5th to 95th is somewhat wider than that of the statistical based approach.

Using these values as a guide, we assumed that the distribution of values for this rule would be similar. Thus, at the 5th percentile, monetized benefits would be roughly $340 million (2000$) and at the 95th percentile, monetized benefits would be roughly $2.7 billion (2000$) assuming a 3 percent discount rate. This is the same discount rate we apply in our benefits estimate listed above. Using estimates derived from the expert elicitation approach and again assuming a 3 percent discount rate, monetized benefits at the 5th percentile would be roughly $68 million (2000$) and at the 95th percentile, monetized benefits would be roughly $4.4 billion (2000$).

With the annualized costs of this rulemaking estimated at $57 million (2000$) in 2015 and with benefits of $1.36 billion (2000$) for that same year, EPA believes that the benefits are likely to exceed the costs. Please refer to the Nonroad diesel RIA for a detailed discussion of the uncertainties considered in EPA's benefit analyses.

For more information, please refer to the RIA for this rule that is available in the docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

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

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2196.01.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The final rule will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be 145,000 labor hours per year at a total annual cost of $9,593,700. This estimate includes a one-time notification, engine certification, and recordkeeping. There are no capital/start-up costs associated with the monitoring requirements over the 3-year period of the ICR. The operation and maintenance costs for the monitoring requirements over the 3-year period of the ICR are estimated to be $242,300 per year.

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

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

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

For the purposes of assessing the impacts of the final rule on small entities, small entity is defined as a small business based on the following Small Business Administration small business size definitions that are based on employee size: NAICS 335312—Motor and Generator Manufacturing—1,000 employees; NAICS 333911—Pump and Pumping Equipment Manufacturing—500 employees; NAICS 333912—Air and Gas Compressor Manufacturing—500 employees; NAICS 333992—Welding and Soldering Equipment Manufacturing—500 employees. In addition, a small governmental jurisdiction is defined as a government of a city, county, town, school district or special district with a population of less than 50,000, and a small organization is defined as any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final rule on small entities, I conclude that this final action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by the final rule are businesses within the NAICS codes mentioned above. There are 104 ultimate parent businesses that will be affected by the final rule. Sixty of these businesses are small according to the SBA small business size standards. Four of these sixty firms will have an annualized compliance cost of more than 1 percent of sales associated with meeting the requirements of the final rule, and one of these four will have a compliance cost of more than 3 percent of sales. For more information on the small entity impacts, refer to the economic impact and small business analyses in the rulemaking docket.

Although the final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless tried to reduce the impact of the final rule on small entities. A majority of the affected facilities are primarily small entities (e.g., small businesses). When developing the rule, EPA took special steps to ensure that the burdens imposed on small entities were reasonable.

EPA is including the same provisions for small manufacturers and small refiners that the nonroad CI engine rule does. EPA is helping small entities by providing a lead time for the required emission standards and fuel requirements. Owners and operators of non-emergency stationary CI ICE are subject to minimum reporting and owners and operators of emergency stationary CI ICE do not have to submit any reports. EPA has also specifically worked with industry to provide special provisions for emergency fire pump engine manufacturers, some of which are small businesses, to develop a rule that is achievable for this segment.

D. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least-costly, most cost-effective, or least-burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least-costly, most cost-effective, or least-burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small

governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments or impose obligations upon them. Therefore, the final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The final rule primarily affects private industry, and does not impose significant economic costs on State or local governments. Thus, Executive Order 13132 does not apply to the final rule.

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

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

The final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

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

The final rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for this determination is provided below.

The economic impact analysis (EIA) estimates changes in prices and production levels for all energy markets (i.e., petroleum, natural gas, electricity, and coal). We also estimate how changes in the energy markets will impact other users of energy, with a focus on those that would employ the non-emergency stationary CI engines affected by the final rule. The estimated increase in demand for ULSD in 2015 (the year for which the impacts of the final rule are estimated) associated with the final rule is 63.2 million gallons, or 1.505 million barrels for that year. This amount is equivalent to 4,123 barrels per day additional demand of ULSD. The expected increase in demand for ULSD will not likely be a difficulty for refiners to meet in 2015. Hence, no significant adverse effect on the supply of this fuel is expected from implementation of the final rule. All impact estimates for other types of energy are below the thresholds that must be evaluated under this Executive Order, and no adverse effects are expected to the distribution and use of energy. The estimates contained within the EIA thus show that there is no significant adverse effect on the supply, distribution, or use of energy associated with the final rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

This final rule involves technical standards. EPA cites the standard test procedures in 40 CFR part 1039, subpart F, which in turn cites the procedures in 40 CFR part 1065, 40 CFR 86.1310 for full flow dilution, 40 CFR 89.412 to 89.418 for raw-gas sampling using steady-state tests, 40 CFR 89.112(c) for partial-flow sampling for gaseous emissions during steady-state tests,

California Regulations for New 1996 and Later Heavy-duty Off-Road Diesel Cycle Engines, 40 CFR 89.112(c), 40 CFR part 86, subpart N (7/1/99), and 40 CFR 86.1309 for non-petroleum diesel fuel. The procedures in 40 CFR part 1065 also allow any CA ARB or International Organization for Standardization (ISO) standard if shown to be equivalent.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these methods. One voluntary consensus standard was found that is potentially applicable to the methods cited. This standard is not acceptable as an alternative for the indicated test procedures, as discussed below.

The voluntary consensus standard ISO IS0 8178–l:1996, "Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—Part 1: Test-bed Measurement of Gaseous and Particulate Exhaust Emissions," is not acceptable as an alternative to the test procedures in §§ 60.4212 and 60.4213 of the final rule (specifically 40 CFR 86.1310) for the following reasons. Although ISO 8178–1:1996 has many of the features of EPA test procedures, the ISO standard allows the gaseous measurements to be made in an undiluted sample whereas EPA procedures in 40 CFR 86.1310 require at least one dilution of the sample. The ISO method does allow the gaseous measurements to be made during the double diluted sampling procedures for PM, but it is not required by the ISO method. Also, in the measurement of hydrocarbons, the ISO method only specifies that the sample lines are to be maintained above 70°C and advises that the flow capacity of the sample lines is used to prevent condensation. In EPA procedures in 40 CFR 86.1310, the sample lines must be maintained at 191°C during the hydrocarbon tests to prevent condensation.

Sections 60.4212 and 60.4213 of the final rule list the testing method included in the regulation. Under § 63.7(f) and § 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on September 11, 2006.

List of Subjects

40 CFR Part 60

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Particulate matter, Reporting and recordkeeping requirements.

40 CFR Part 85

Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Warranties.

40 CFR Part 89

Administrative practice and procedure, Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Vessels, Warranties.

40 CFR Part 94

Administrative practice and procedure, Air pollution control, Imports, Penalties, Reporting and recordkeeping requirements, Vessels, Warranties.

40 CFR Part 1039

Administrative practice and procedure, Air pollution control.

40 CFR Part 1065

Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements, Research.

40 CFR Part 1068

Administrative practice and procedure, Air pollution control, Imports, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements, Warranties.

Dated: June 28, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended to read as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[AMENDED]

■ 2. Section 60.17(a) is amended by redesignating paragraphs (a)(84) through (a)(91) as paragraphs (a)(85) through (a)(92), respectively and adding a new paragraph (a)(84) to read as follows:

§ 60.17 Incorporations by Reference.

* * * * *

(a) * * *

(84) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for table 7 of Subpart IIII of this part.

* * * * *

■ 3. Part 60 is amended by adding subpart IIII to read as follows:

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers

Sec.

60.4200 Am I subject to this subpart?

Emission Standards for Manufacturers

60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Emission Standards for Owners and Operators

60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30

liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_x) emissions by 90 percent or more, or limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_x emissions by 90 percent or more, or limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in § 60.4201(a) through (c) and § 60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in § 60.4201(d) and § 60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must

refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§ 60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§ 60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards

specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under § 60.4205 but not § 60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in § 60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model

year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2 − 15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 − 15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in § 60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in § 60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under § 60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of § 60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4202 or § 60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment

(including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Tables to Subpart IIII of Part 60

TABLE 1 TO SUBPART IIII OF PART 60.—EMISSION STANDARDS FOR STATIONARY PRE-2007 MODEL YEAR ENGINES WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER AND 2007–2010 MODEL YEAR ENGINES >2,237 KW (3,000 HP) AND WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)	.....	.....	8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)	.....	.....	6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)	.....	.....	5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	.....	.....	9.2 (6.9)	.....	.....
56≤KW<75 (75≤HP<100)	.....	.....	9.2 (6.9)	.....	.....
75≤KW<130 (100≤HP<175)	.....	.....	9.2 (6.9)	.....	.....
130≤KW<225 (175≤HP<300)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)	.....	1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

TABLE 2 TO SUBPART IIII OF PART 60.—EMISSION STANDARDS FOR 2008 MODEL YEAR AND LATER EMERGENCY STATIONARY CI ICE <37 KW (50 HP) WITH A DISPLACEMENT OF <10 LITERS PER CYLINDER

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

TABLE 3 TO SUBPART IIII OF PART 60.—CERTIFICATION REQUIREMENTS FOR STATIONARY FIRE PUMP ENGINES

[As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

TABLE 4 TO SUBPART IIII OF PART 60.—EMISSION STANDARDS FOR STATIONARY FIRE PUMP ENGINES

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

TABLE 5 TO SUBPART IIII OF PART 60.—LABELING AND RECORDKEEPING REQUIREMENTS FOR NEW STATIONARY EMERGENCY ENGINES

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

TABLE 6 TO SUBPART IIII OF PART 60.—OPTIONAL 3-MODE TEST CYCLE FOR STATIONARY FIRE PUMP ENGINES

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed [1]	Torque (percent) [2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.
[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

TABLE 7 TO SUBPART IIII OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥30 LITERS PER CYLINDER

[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder.	a. Reduce NO_X emissions by 90 percent or more.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine.	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see § 60.17).	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) Sampling sites must be located at the inlet and outlet of the control device.

TABLE 7 TO SUBPART IIII OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS FOR STATIONARY CI ICE WITH A DISPLACEMENT OF ≥30 LITERS PER CYLINDER—Continued

[As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A.	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A.	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A.	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A.	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A.	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

TABLE 8 TO SUBPART IIII OF PART 60.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes.	
§ 60.10	State Authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes.	

TABLE 8 TO SUBPART IIII OF PART 60.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART IIII—Continued

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements ..	Yes.	

PART 85—[AMENDED]

■ 4. The authority citation for part 85 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 5. Section 85.2401 is amended by revising paragraphs (a)(6), (a)(11), and (a)(12) and adding paragraph (a)(13) to read as follows:

§ 85.2401 To whom do these requirements apply?

(a) * * *

(6) Nonroad compression-ignition engines (See 40 CFR parts 89 and 1039);

* * * * *

(11) Heavy-duty highway gasoline vehicles (evaporative emissions certification only) (See 40 CFR part 86);

(12) Large nonroad spark-ignition engines (engines >19 KW) (See 40 CFR part 1048); and

(13) Stationary internal combustion engines (See 40 CFR part 60, subpart IIII).

* * * * *

■ 6. Section 85.2403 is amended by revising the definition for "Federal certificate" in paragraph (a), revising paragraphs (b)(8) and (b)(9), and adding paragraphs (b)(10) and (b)(11) to read as follows:

§ 85.2403 What definitions apply to this subpart?

(a) * * *

* * * * *

Federal certificate is a Certificate of Conformity issued by EPA which signifies compliance with emission requirements in any of the parts specified in paragraph (b) of this section.

* * * * *

(b) * * *

(8) 40 CFR part 1039;

(9) 40 CFR part 1048;

(10) 40 CFR part 1051; and

(11) 40 CFR part 60, subpart IIII.

■ 7. Section 85.2405 is amended by adding paragraph (e) to read as follows:

§ 85.2405 How much are the fees?

* * * * *

(e) Fees for stationary CI internal combustion engine certificate requests shall be calculated in the same manner as for NR CI certificate requests for engines with a displacement less than 10 liters per cylinder, and in the same manner as for marine engine certificate requests for engines with a displacement greater than or equal to 10 liters per cylinder. Fees for certificate requests where the certificate would apply to stationary and mobile engines shall be calculated in the same manner as fees for the certificate requests for the applicable mobile source engines.

PART 89—[AMENDED]

■ 8. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 9. Section 89.1 is amended by adding paragraph (d) to read as follows:

§ 89.1 Applicability.

* * * * *

(d) This part applies as specified in 40 CFR part 60 subpart IIII, to compression-ignition engines subject to the standards of 40 CFR part 60, subpart IIII.

■ 10. Section 89.115 is amended by adding paragraph (d)(11) to read as follows:

§ 89.115 Application for certificate.

* * * * *

(d) * * *

(11) A statement indicating whether the engine family contains only nonroad engines, only stationary engines, or both.

■ 11. Section 89.201 is revised to read as follows:

§ 89.201 Applicability.

Nonroad compression-ignition engines subject to the provisions of subpart A of this part are eligible to participate in the averaging, banking, and trading program described in this subpart. To the extent specified in 40 CFR part 60, subpart IIII, stationary engines certified under this part and subject to the standards of 40 CFR part 60, subpart IIII, may participate in the averaging, banking, and trading program described in this subpart.

PART 94—[AMENDED]

■ 12. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 13. Section 94.1 is amended by adding paragraph (d) to read as follows:

§ 94.1 Applicability.

* * * * *

(d) This part applies as specified in 40 CFR part 60, subpart IIII, to compression-ignition engines subject to the standards of 40 CFR part 60, subpart IIII.

■ 14. Section 94.301 is revised to read as follows:

§ 94.301 Applicability.

Marine engine families subject to the standards of subpart A of this part are eligible to participate in the certification averaging, banking, and trading program described in this subpart. The provisions of this subpart apply to manufacturers of new engines that are subject to the emission standards of § 94.8. To the extent specified in 40 CFR part 60, subpart IIII, stationary engines certified under this part and subject to the standards of 40 CFR part 60, subpart IIII, may participate in the averaging, banking, and trading program described in this subpart.

PART 1039—[AMENDED]

■ 15. The authority citation for part 1039 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 16. Section 1039.1 is amended by revising paragraph (c) to read as follows:

§ 1039.1 Does this part apply for my engines?

* * * * *

(c) The definition of nonroad engine in 40 CFR 1068.30 excludes certain engines used in stationary applications. These engines may be required by subpart IIII of 40 CFR part 60 to comply with some of the provisions of this part 1039; otherwise, these engines are only required to comply with the requirements in § 1039.20. In addition, the prohibitions in 40 CFR 1068.101 restrict the use of stationary engines for nonstationary purposes unless they are certified under this part 1039, or under the provisions of 40 CFR part 89 or 40 CFR part 94, to the same standards that would apply to nonroad engines for the same model year.

* * * * *

■ 17. Section 1039.20 is amended by revising paragraphs (a) and (b) and adding paragraph (c) to read as follows:

§ 1039.20 What requirements from this part apply to excluded stationary engines?

* * * * *

(a) You must add a permanent label or tag to each new engine you produce or import that is excluded under § 1039.1(c) as a stationary engine and is not required by 40 CFR part 60, subpart IIII, to meet the requirements of this part 1039, or the requirements of parts 89 or 94, that are equivalent to the requirements applicable to nonroad or marine engines for the same model year. To meet labeling requirements, you must do the following things:

(1) Attach the label or tag in one piece so no one can remove it without destroying or defacing it.

(2) Secure it to a part of the engine needed for normal operation and not normally requiring replacement.

(3) Make sure it is durable and readable for the engine's entire life.

(4) Write it in English.

(5) Follow the requirements in § 1039.135(g) regarding duplicate labels if the engine label is obscured in the final installation.

(b) Engine labels or tags required under this section must have the following information:

(1) Include the heading "EMISSION CONTROL INFORMATION."

(2) Include your full corporate name and trademark. You may instead include the fill corporate name and trademark of another company you choose to designate.

(3) State the engine displacement (in liters) and maximum engine power (or in the case of fire pumps, NFPA nameplate engine power).

(4) State: "THIS ENGINE IS EXEMPTED FROM THE REQUIREMENTS OF 40 CFR PARTS 89 AND 1039 AS A "STATIONARY ENGINE." INSTALLING OR USING THIS ENGINE IN ANY OTHER APPLICATION MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY."

(c) Stationary engines required by 40 CFR part 60, subpart IIII, to meet the requirements of this part 1039, or parts 89 or 94, must meet the labeling requirements of 40 CFR 60.4210.

■ 18. Section 1039.205 is amended by revising paragraph (v) to read as follows:

§ 1039.205 What must I include in my application?

* * * * *

(v) State whether your certification is intended to include engines used in stationary applications. State whether your certification is limited for certain engines. If this is the case, describe how you will prevent use of these engines in applications for which they are not certified. This applies for engines such as the following:

(1) Constant-speed engines.

(2) Engines used for transportation refrigeration units that you certify under the provisions of § 1039.645.

(3) Hand-startable engines certified under the provisions of § 1039.101(c).

(4) Engines above 560 KW that are not certified to emission standards for generator-set engines.

* * * * *

■ 19. Section 1039.705 is amended by revising paragraph (c) to read as follows:

§ 1039.705 How do I generate and calculate emission credits?

* * * * *

(c) In your application for certification, base your showing of compliance on projected production volumes for engines whose point of first retail sale is in the United States. As described in § 1039.730, compliance with the requirements of this subpart is determined at the end of the model year based on actual production volumes for engines whose point of first retail sale is in the United States. Do not include any of the following engines to calculate emission credits:

(1) Engines exempted under subpart G of this part or under 40 CFR part 1068.

(2) Exported engines.

(3) Engines not subject to the requirements of this part, such as those excluded under § 1039.5.

(4) Engines in families that include only stationary engines, except for engines in families certified to standards that are identical to standards applicable under this part 1039 to nonroad engines of the same type for the same model year.

(5) Any other engines, where we indicate elsewhere in this part 1039 that they are not to be included in the calculations of this subpart.

PART 1065—[AMENDED]

■ 20. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 21. Section 1065.1 is amended by adding paragraph (a)(5) to read as follows:

§ 1065.1 Applicability.

(a) * * *

(5) Stationary compression-ignition engines certified using the provisions of 40 CFR part 1039, as indicated under 40 CFR part 60, subpart IIII, the standard-setting part for these engines.

* * * * *

PART 1068—[AMENDED]

■ 22. The authority citation for part 1068 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 23. Section 1068.1 is amended by adding paragraph (a)(4) to read as follows:

§ 1068.1 Does this part apply to me?

(a) * * *

(4) Stationary compression-ignition engines certified to the provisions of 40 CFR part 1039, as indicated under 40 CFR part 60, subpart IIII.

* * * * *

■ 24. Section 1068.310 is amended by revising paragraph (b) to read as follows:

§ 1068.310 What are the exclusions for imported engines?

* * * * *

(b) *Stationary engines.* The definition of nonroad engine in 40 CFR 1068.30 does not include certain engines used in stationary applications. Such engines may be subject to the standards of 40 CFR part 60. Engines that are excluded from the definition of nonroad engine in this part and not required to be certified to standards under 40 CFR part 60 are not subject to the restrictions on imports in § 1068.301(b), but only if they are properly labeled. Section 1068.101 restricts the use of stationary engines for non-stationary purposes unless they are certified under 40 CFR Part 60 to the same standards that would apply to nonroad engines for the same model year.

* * * * *

[FR Doc. 06–5968 Filed 7–10–06; 8:45 am]
BILLING CODE 6560–50–P

Federal Register

Thursday,
July 6, 2006

Part III

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Stationary Combustion Turbines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2004–0490, FRL–8033–4]

RIN 2060–AM79

Standards of Performance for Stationary Combustion Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates standards of performance for new stationary combustion turbines in 40 CFR part 60, subpart KKKK. The standards reflect changes in nitrogen oxides (NO_X) emission control technologies and turbine design since standards for these units were originally promulgated in 40 CFR part 60, subpart GG. The NO_X and sulfur dioxide (SO_2) standards have been established at a level which brings the emissions limits up to date with the performance of current combustion turbines.

DATES: *Effective date:* The final rule is effective July 6, 2006. The incorporation by reference of certain publications in the final rule is approved by the Director of the Office of the Federal Register as of July 6, 2006.

ADDRESSES: *Docket:* EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0490. All documents in the docket are listed electronically on *www.regulations.gov*. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, Docket ID No. EPA–HQ–OAR–2004–0490, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–4003; facsimile number (919) 541–5450; e-mail address *fellner.christian@epa.gov*.

SUPPLEMENTARY INFORMATION:

Regulated Entities. Categories and entities potentially regulated by this action are those that own and operate stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (GJ) (10 million British thermal units (MMBtu)) per hour that commenced construction, modification, or reconstruction after February 18, 2005. Regulated categories and entities include, but are not limited to:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a new stationary combustion turbine as defined in the final rule	2211	4911	Electric services.
	486210	4922	Natural gas transmission.
	211111	1311	Crude petroleum and natural gas.
	211112	1321	Natural gas liquids.
	221	4931	Electric and other services, combined.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is available on the WWW through the Technology Transfer Network Website (TTN Web). Following signature, EPA will post a copy of the final rule on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by September 5, 2006. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by today's final action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for EPA to convene a proceeding for reconsideration, "if the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20004.

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background

This action promulgates new source performance standards (NSPS) that apply to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour, based on the higher heating value (HHV) of the fuel, that commence construction, modification, or reconstruction after February 18, 2005. The NSPS are being promulgated pursuant to section 111 of the CAA, which requires EPA to promulgate and periodically revise the NSPS, taking into consideration available control technologies and the costs of control. EPA promulgated the original NSPS for stationary gas turbines in 1979 (44 FR 52798). Since promulgation of the NSPS for stationary gas turbines, many advances in the design and control of emissions from stationary combustion turbines have occurred. Nitrogen oxides and SO_2 are known to cause adverse health and environmental effects. The final rule represents reductions in the NO_X and SO_2 limits of over 80 and 90 percent, respectively. Today's action allows turbine owners and operators to meet either concentration-based or output-based standards. The output-based standards in the final rule allow owners and operators the flexibility to meet their emission limit targets by increasing the efficiency of their turbines.

II. Summary of the Final Rule

A. Does the final rule apply to me?

Today's final rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour that commence construction, modification, or reconstruction after February 18, 2005. A stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. The applicability of the final rule is similar to that of 40 CFR part 60, subpart GG, except that the final rule applies to new, modified, and reconstructed stationary combustion turbines, and their associated heat recovery steam generators (HRSG) and duct burners. The stationary combustion turbines subject to subpart KKKK, 40 CFR part 60, are exempt from the requirements of 40 CFR part 60, subpart GG. Heat recovery steam generators and duct burners subject to subpart KKKK are exempt from the requirements of 40 CFR part 60, subparts Da, Db, and Dc.

B. What pollutants are regulated?

The pollutants that are regulated by the final rule are NO_X and SO_2.

C. What is the affected source?

The affected source for the stationary combustion turbine NSPS is each stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour that commences construction, modification, or reconstruction after February 18, 2005. Integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility Boiler NSPS) are exempt from the requirements of the final rule. Combustion turbine test cells/stands are also exempt from the requirements of the final rule.

D. What emission limits must I meet?

The standards for NO_X in the final rule allow the turbine owner or operator the choice of a concentration-based or output-based emission standard. The concentration-based limit is in units of parts per million by volume (ppmv) at 15 percent oxygen. The output-based emission limit is in units of emissions mass per unit useful recovered energy, nanograms per Joule (ng/J) or pounds per megawatt-hour (lb/MWh). The NO_X limits, which are presented in table 1 of this preamble, differ based on the fuel input at peak load, fuel, application, and location of the turbine. The fuel input of the turbine does not include any supplemental fuel input to the heat recovery system and refers to the rating of the combustion turbine itself. The 50 MMBtu/h category peak heat input is based on the fuel input to a 23 percent efficient 3.5 megawatt (MW) combustion turbine. The 850 MMBtu/h category peak heat input is based on the fuel input to a 44 percent efficient 110 MW combustion turbine. The 30 MW category for turbines located north of the Arctic Circle, turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0°F is based on the categories in the original NSPS for combustion turbines, subpart GG.

TABLE 1.—NO_X EMISSION STANDARDS

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating.	≤ 50 million British thermal units per hour(MMBtu/h).	42 ppm at 15 percent oxygen (O_2) or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh).
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).

TABLE 1.—NO_X EMISSION STANDARDS—Continued

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas ..	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F.	≤ 30 megawatt (MW) output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 °F.	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

We have determined that it is appropriate to exempt emergency combustion turbines from the NO_X limit. We have defined these units as turbines that operate in emergency situations. For example, turbines used to supply electric power when the local utility service is interrupted are considered to fall under this definition. Stationary combustion turbine test cells/stands are also exempt from the final rule. Combustion turbines used by manufacturers in research and development of equipment for both combustion turbine emissions control techniques and combustion turbine efficiency improvements are exempt from the NO_X limits on a case-by-case basis. Given the small number of turbines that are expected to fall under this category and since there is not one definition that can provide an all-inclusive description of the type of research and development work that qualifies for the exemption from the NO_X limit, we have decided that it is appropriate to make these exemption determinations on a case-by-case basis only.

The emission standard for SO_2 is the same for all turbines regardless of size and fuel type. You may not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross energy output for turbines that are located in continental areas, and 780 ng/J (6.2 lb/MWh) gross energy output for turbines located in noncontinental areas. You can choose to comply with the SO_2 limit itself or with a limit on the sulfur content of the fuel. The fuel sulfur content limit is 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for turbines located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input in noncontinental areas. This is approximately equivalent to 0.05 percent by weight (500 parts per million by weight (ppmw)) fuel oil and 0.4 percent by weight (4,000 ppmw) fuel oil respectively.

E. If I modify or reconstruct my existing turbine, does the final rule apply to me?

The final rule applies to stationary combustion turbines that are modified or reconstructed after February 18, 2005. The methods for determining whether a source is modified or reconstructed are provided in 40 CFR 60.14 and 40 CFR 60.15, respectively. A turbine that is overhauled as part of a maintenance program is not considered a modification if there is no increase in emissions.

F. How do I demonstrate compliance?

In order to demonstrate compliance with the NO_X limit, an initial performance test is required. If you are using water or steam injection, you must continuously monitor your water or steam to fuel ratio in order to demonstrate compliance and you are not required to perform annual stack testing to demonstrate compliance. If you are not using water or steam injection, you must conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests.

If you are using a NO_X CEMS, the initial performance test required under 40 CFR 60.8 may, alternatively, coincide with the relative accuracy test audit (RATA). If you choose this as your initial performance test, you must perform a minimum of nine reference method runs, with a minimum time per run of 21 minutes, at a single load level, within 75 percent of peak (or the highest achievable) load. You must use the test data both to demonstrate compliance with the applicable NO_X emission limit and to provide the required reference method data for the RATA of the CEMS.

G. What monitoring requirements must I meet?

If you are using water or steam injection to control NO_X emissions, you must install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being

fired in the turbine. Alternatively, you could use a CEMS consisting of NO_X and O_2 or carbon dioxide (CO_2) monitors. During each full unit operating hour, each monitor must complete a minimum of one cycle of operation for each 15-minute quadrant of the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates.

If you operate any new turbine which does not use water or steam injection to control NO_X emissions, you must perform annual stack testing to demonstrate continuous compliance with the NO_X limit. Alternatively, you could elect either to use a NO_X CEMS or perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define appropriate parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously;

(2) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in the low NO_X combustion mode;

(3) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls; and

(4) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in 40 CFR 75.19, the monitoring requirements of the turbine NSPS may be met by performing the parametric monitoring described in section 2.3 of appendix E of part 75 of this chapter or in 40 CFR 75.19(c)(1)(iv)(H).

Alternatively, you can petition the Administrator for other acceptable methods of monitoring your emissions. If you choose to use a CEMS or perform parameter monitoring to demonstrate continuous compliance, annual stack testing is not required.

If you choose to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test to establish acceptable operating ranges.

If you operate any stationary combustion turbine subject to the provisions of the final rule, and you choose not to comply with the SO_2 stack limit, you must monitor the total sulfur content of the fuel being fired in the turbine. There are several options for determining the frequency of fuel sampling, consistent with appendix D to part 75 of this chapter for fuel oil; the sulfur content must be determined and recorded once per unit operating day for gaseous fuel, unless a custom fuel sampling schedule is used. Alternatively, you could elect not to monitor the total potential sulfur emissions of the fuel combusted in the turbine, if you demonstrate that the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for turbines located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input in noncontinental areas. This demonstration may be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data which show that the potential sulfur emissions of the fuel does not exceed the standard. Turbines located in continental areas can demonstrate compliance by burning fuel oil containing 500 parts per million (ppm) or less sulfur or natural gas containing 20 grains or less of sulfur per 100 standard cubic feet. Turbines located in noncontinental areas can demonstrate compliance by burning fuel oil containing 0.4 weight percent (4,000 ppm) sulfur or less or natural gas containing 140 grains or less of sulfur per 100 standard cubic feet.

If you are required to periodically determine the sulfur content of the fuel combusted in the turbine, a fuel sample must be collected during the performance test. For liquid fuels, the sample for the total sulfur content of the fuel must be analyzed using American Society of Testing and Materials (ASTM) methods D129–00 (Reapproved 2005), D1266–98 (Reapproved 2003), D1552–03, D2622–05, D4294–03, or D5453–05. For gaseous fuels, ASTM D1072–90 (Reapproved 1999); D3246–05; D4468–85 (Reapproved 2000); or D6667–04 must be used to analyze the total sulfur content of the fuel.

The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

H. What reports must I submit?

For each affected unit for which you continuously monitor parameters or emissions, or periodically determine the fuel sulfur content under the final rule, you must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). For simple cycle turbines, excess emissions must be reported for all 4-hour rolling average periods of unit operation, including start-up, shutdown, and malfunctions where emissions exceed the allowable emission limit or where one or more of the monitored process or control parameters exceeds the acceptable range as determined in the monitoring plan. Combined cycle and combined heat and power units use a 30-day rolling average to determine excess emissions.

For each affected unit for which you perform an annual performance test, you must submit an annual written report of the results of each performance test.

III. Summary of Significant Changes Since Proposal

A. Applicability

The proposed rule applied to owners and operators of stationary combustion turbines with a peak power output at peak load equal to or greater than 1 MW. The final rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 GJ (10 MMBtu) per hour, based on the HHV of the fuel. Assuming an efficiency of 23 percent, the final rule applies to stationary combustion turbines with a peak output greater than 0.7 MW. Another change from the proposed rule is the addition of an exemption for stationary combustion turbine test cells/stands.

B. Emission Limitations

The proposed rule established four subcategories of turbines based on fuel type and turbine size, and different NO_X emission standards were proposed for each subcategory. The proposed subcategories were the following: Less than 30 MW and firing natural gas; greater than or equal to 30 MW and firing natural gas; less than 30 MW and firing oil or other fuel; and greater than or equal to 30 MW and firing oil or other fuel. The final rule has 14 subcategories, which are listed in table 1 of this preamble. Instead of the proposed size break at 30 MW, the final rule breaks the turbines into subcategories of less than or equal to 50 MMBtu/h of heat input, greater than 50 MMBtu/h heat input to less than or equal to 850 MMBtu/h heat input, and greater than 850 MMBtu/h heat input. Subcategories have been included for modified and reconstructed turbines, heat recovery units operating independent of the combustion turbine, turbines located north of the Arctic

Circle, and turbines operating at part load. EPA concluded that subcategories based on heat input at peak load rather than power output are more appropriate. The boiler NSPS standards are subcategorized by heat input, and heat input is a better indication than power output of available combustion controls. Basing categories on heat input also eliminates the disincentive of turbine redesign that increases efficiency and output, but not fuel consumption.

The proposed standards for NO_X were output-based limits in units of emissions mass per unit useful recovered energy, ng/J or lb/MWh. This format has been retained in the final rule; however, an optional concentration-based standard in units of ppmv at 15 percent O_2 has also been included for each subcategory.

The proposed SO_2 emission limits were raised slightly in the final rule, and an additional subcategory was created. Different emission limits were provided for turbines located in noncontinental areas; those turbines have an SO_2 emission limit of 780 ng/J (6.2 lb/MWh). The other difference from the proposed rule is that turbines located in Alaska do not have to meet the SO_2 emission limits until January 1, 2008.

C. Testing and Monitoring Procedures

The final rule contains several differences from the proposed testing and monitoring procedures. The performance test for NO_X is not required to be conducted at four load levels; in the final rule the test must be conducted at one load level that is within plus or minus 25 percent of 100 percent of peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. We added a requirement that the ambient temperature be greater than 0 °F when the test is conducted. Similarly, we specified in the final rule that turbine owners and operators that are continuously monitoring parameters or emissions have an alternate limit during periods when the turbine operates at less than 75 percent of peak load or the ambient temperature is less than 0 °F.

A provision was added that allows owners and operators of stationary combustion turbines to reduce the frequency of subsequent NO_X performance tests to once every 2 years if the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine. If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, annual performance tests must be resumed.

The sulfur sampling requirements in the final rule also contain some differences from the proposed requirements. Acceptable custom schedules for determining the total sulfur content of gaseous fuels were added in the final rule. We removed the statement that was in the proposed rule that required at least one fuel sample to be collected during each load condition, since we are no longer requiring performance tests to be conducted at multiple loads.

Finally, the proposed rule required that diffusion flame turbines without SCR controls continuously monitor at least four parameters indicative of the unit's NO_X formation characteristics; the final rule does not specify a minimum number of parameters that must be continuously monitored by these units.

D. Reporting

The reporting requirements in the final rule contain two differences from the proposed reporting requirements. The proposed 40 CFR 60.4395 said that reports should be postmarked by the 30th day following the end of each calendar quarter. The proposed rule actually required semiannual reports, therefore, that section should have read that the reports should be postmarked by the end of each 6-month period, and the final rule has been written to correct this error. Also, we specified that turbines that are conducting annual performance testing should submit annual reports with the results of the performance testing.

E. Other

Several modifications were made to the definitions in the proposed rule. The definition of efficiency was clarified to indicate that it is based on the HHV of the fuel. The definitions for lean premix stationary combustion turbine and diffusion flame stationary combustion turbine were modified to alleviate any potential ambiguity about which definition a turbine would fall under. Lastly, the definition of natural gas was revised to remove references to pipeline natural gas.

IV. Summary of Responses to Major Comments

A more detailed summary of comments and our responses can be found in the Response to Public Comments on Proposed Standards of Performance for Stationary Combustion Turbines document, which can be obtained from the docket.

A. Applicability

Comment: Several commenters suggested changing the minimum size threshold for applicability of the rule, as proposed. Some suggested 3 MW, while others suggested 3.5 MW. Reasons included the fact that lean premix technology is not available for turbines less than 3 MW, other control options are not feasible, no commercially available small units were identified that can achieve the proposed emission levels, and no emission test data were provided in the docket for small units.

Another reason given was that there was some ambiguity because of the differing minimum size criteria between the rule, as proposed, and 40 CFR part 60, subpart GG. Two commenters suggested that EPA clarify that subpart KKKK, 40 CFR part 60, is the effective NSPS, and that 40 CFR part 60, subpart GG, no longer applies for all new, reconstructed, or modified stationary combustion turbines. The commenters said that it is not clear if 40 CFR part 60, subpart GG, will no longer apply after the effective date of the final rule. Since the minimum size criterion was slightly different in the two subparts, the commenters requested clarification of this issue to avoid future confusion. The commenters requested that EPA clarify that 40 CFR part 60, subpart GG, no longer applies after the effective date of the final rule.

Response: This comment addresses the minimum size threshold for the final rule. In 40 CFR 60.4305 of the rule, as proposed, the applicability criteria stated that the applicable units are turbines with a peak load power output equal to or greater than 1 MW. This minimum size threshold is marginally higher than the minimum threshold in 40 CFR part 60, subpart GG, which affects turbines with a minimum heat input at peak load of 10.7 GJ per hour or larger based on the lower heating value of the fuel (approximately 10 MMBtu/h). With a lower heating value (LHV) thermal efficiency of 23 to 25 percent, which is typical at full load for older small industrial turbines, this firing rate is equivalent to 0.7 MW. While the difference between the 40 CFR part 60, subpart GG, and the proposed 40 CFR part 60, subpart KKKK, applicability thresholds was initially believed to be minor, the natural gas industry representatives pointed out that there is a class of turbines used in natural gas transmission that fall within this range. Solar Saturn units, which are widely used in the gas transmission industry, include a peak load between 0.7 and 1.0 MW. While the industry has said that

not many new units are sold in this range, there are many already in existence, which may be modified or reconstructed, which would need to be addressed by one of the rules. Therefore, the final rule has been written to include the minimum size applicability threshold of 10.7 GJ per hour.

While we do not agree that the size cutoff should be established to exempt turbines less than 3.5 MW, EPA has concluded that it is appropriate to create a new subcategory. Discussions with turbine manufacturers suggest that a subcategory for small turbines, between the minimum size threshold for the final rule and 50 MMBtu/h (HHV), should be created. This division is based on the fuel input to a 23 percent efficient 3.5 MW turbine. The only turbine identifiable in this size range that can be used for mechanical drive applications is a Solar Saturn, and Solar Turbines does not plan to further develop dry low NO_X technology on the Saturn line, nor does it have that capability at the current time. According to the gas transmission industry representatives, there are about 300 turbines in this small size range, comprising over 25 percent of the existing turbines in gas transmission. None of these units include lean premixed combustion. Other add-on controls have not been applied to the variable load operating profile characteristic of gas transmission equipment, nor would such add-on controls be economically feasible for these small units with minimal emissions. Therefore, the final rule has incorporated a new subcategory of small turbines, ranging from the applicability limit to 50 MMBtu/h.

Comment: Several commenters suggested that modified and reconstructed units should be treated differently than new units. Reasons provided by the commenters included costs for retrofitting being excessive, and weight and space needs being prohibitive. One commenter stated that there are many existing turbines that could be affected by the modification section of the rule for which there is no cost effective technology that achieves emissions lower than those suggested by the commenter. One commenter stated that the terms "modification" and "reconstruction" were not clearly defined, and that requiring these units to meet the same limits as new units may discourage existing turbine users from modifying units to improve efficiency or lower emissions, if such modifications do not ensure compliance with the limit for new units.

Options recommended by the commenters included removing them from the applicability of 40 CFR part 60, subpart KKKK, giving them separate limits under subpart KKKK, or making them subject to 40 CFR part 60, subpart GG. One commenter recommended that units manufactured through 1985 (20 years and older) be exempted from the requirements of the proposed NSPS, and the previous NSPS levels should apply.

Response: We acknowledge the commenters' views, and in the final rule there are new subcategories for some modified and reconstructed units. While we provided more flexibility in the final rule for small and medium sized turbines (ranging from the applicability threshold to 850 MMBtu/h), we had no information on large turbines (greater than 850 MMBtu/h) which would suggest any compliance issues for modified or reconstructed units. Therefore, no subcategory was added for large (greater than 850 MMBtu/h) modified or reconstructed units.

Comment: Several commenters suggested that EPA include an exemption for offshore turbines, turbines located north of the Arctic Circle, and turbines in other existing remote locations. Alternatively, the commenters suggested subcategorizing them separately. The commenters said that due to a harsh environment and fuel availability and variability, these turbines are commonly diffusion flame, and land-based emissions abatement techniques are unsuitable; space limitations are also a concern. One commenter said that the rule, as proposed, would preclude the use of new, modified or reconstructed turbines located in electric utility service in Alaska, because of the additional costs associated with meeting the proposed limits.

Response: EPA has concluded that a subcategory should be created for modified and reconstructed offshore turbines and turbines installed north of the Arctic Circle to recognize their distinct differences. There is a substantial difference in temperature between the North Slope of Alaska and even the coldest areas in the lower 48 States. As noted by the commenters, turbine operators on the North Slope of Alaska have experienced problems with operation of the turbines in lean premix mode, and turbine manufacturers do not guarantee the performance of their turbines at the ambient temperatures typically found north of the Arctic Circle. Therefore, a subcategory for turbines operated north of the Arctic Circle has been established.

With regards to the rest of Alaska, EPA concluded that the final rule includes limits which will reduce or eliminate the need for add-on controls for the vast majority of turbines, and that these new emission limitations address the concerns of the commenters.

Modified and reconstructed offshore turbines have been given a subcategory due to the lack of space on platforms for additional controls.

The subcategories for these turbines are based on power output instead of heat input at peak load. Since the standards for these subcategories are similar to 40 CFR part 60, subpart GG, EPA used the same categories as subpart GG to avoid being less stringent than the existing emissions standards.

Comment: Several commenters had issues with periods of startup, shutdown and malfunction. Some commenters believed that the averaging times that are specified for continuous monitoring (using either a CEMS or parametric monitoring) were too short to accommodate such periods. The commenters believed that exceptions should be developed for periods of startup, shutdown and maintenance if 4-hour averages were maintained. One commenter suggested 30-day rolling averages, one commenter suggested 24-hour rolling averages, and one commenter suggested 12-month rolling averages.

One commenter wanted clarification of the applicability of the NO_X standards during periods of startup, shutdown and malfunction. Two commenters pointed out that while these periods of excess emissions were not considered violations, they might appear to be to State regulatory agencies or the public. Another commenter requested that EPA allow sources to permit emissions associated with startup and shutdown events where it is not feasible to have the same emission profile as normal operating conditions. This commenter requested that a clarification be made that deviating from a monitored parameter only results in excess emissions if emissions calculated from that parameter result in exceeding an emission limit for the averaging period used to demonstrate compliance.

One commenter was particularly concerned about combined cycle units with longer startup periods as part of a normal startup cycle. The commenter felt that this should not constitute a malfunction, and should not be reported in an excess emissions report. Another commenter asked that a reasonable startup period (up to 24 hours) be provided for units with SCR, since minimum temperatures must be met.

Response: The final rule states that excess emissions and deviations must be recorded during periods of startup, shutdown, and malfunction. We recognize that even for well-operated

units with efficient NO_X emission controls, excess emission "spikes" during unit startup and shutdown are inevitable, and malfunctions of emission controls and process equipment occasionally occur. However, at all times, including periods of startup, shutdown, and malfunction, 40 CFR 60.11(d) requires affected units to be operated in a manner consistent with good air pollution control practice for minimizing emissions. Excess emissions data may be used to determine whether a facility's operation and maintenance procedures are consistent with 40 CFR 60.11(d). While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported. Thus, we retained the 4-hour rolling average period in the final rule for simple cycle units. We realize that including units with heat recovery under the combustion turbine NSPS adds additional compliance issues for those units. Boiler NO_X emissions vary over short time periods and short averaging times make the output-based options unworkable due to the difficulty in continuously taking full advantage of the recovered thermal energy. For units with heat recovery and CEMS, the standard is therefore determined on a 30-day rolling average. Under the previous NSPS, heat recovery units are covered under either subpart Da, Db, or Dc, 40 CFR part 60. Those standards determine compliance based on a 30-day rolling average. In recognition of these factors, EPA concluded that a 30-day rolling average is the appropriate averaging time for units that are using recovered thermal energy. Since simple cycle turbines are used primarily for peaking applications, a 30-day average is not practical for these units. Initial compliance determinations could take several years, and once a unit is determined to be out of compliance it could take several years for the 30-day average to return below the standard.

In regards to parametric monitoring, a deviation from a monitored parameter only results in excess emissions if the calculations show an exceedence of the emission limit. This is clearly communicated in the final rule, in the section entitled "How do I establish and document a proper parameter monitoring plan?" Regarding the negative stigma, we cannot determine how other parties interpret the final rule. It is clear that continuous compliance is not a requirement of the final rule during periods of startup, shutdown, and malfunction.

B. NO_X Emission Standards

Comment: Numerous commenters recommended that there be some type of concentration-based standards for NO_X. One commenter said that while it applauds EPA's proposed shift to output-based standards, they might not be applicable in all situations. The commenter said that it is unclear how the calculation would work for a turbine with a bypass stack or another situation where heat is wasted. In addition, the commenter believed that an increased level of effort for monitoring parameters is required, which creates financial and technical burdens for compliance. The commenter recommended that EPA provide an optional concentration-based standard that can be used where data for calculating an output-based standard are unavailable or inappropriate.

One commenter recommended a ppmv standard consistent with current regulations, or a separate standard for simple cycle and combined cycle units. The commenter cited some of the following as rationale for its suggestion: Many State implementation plan regulations and best available control technology analyses are in ppmv, and 40 CFR part 60, subpart GG, is in ppmv; efficiency varies over load; carbon monoxide (CO) needs to be balanced; there are a limited number of units able to meet output-based limits without SCR; and output-based standards add complexity and computational and measurement uncertainty. Another commenter recommended that EPA allow optional concentration-based standards (i.e., ppmv corrected to 15 percent oxygen) so that if a source does not need energy efficiency adjustments to show compliance, it could choose to measure only emission concentrations at the stack.

Two commenters said that EPA should replace the output-based NO_X emission limit with a concentration-based standard for turbines less than 30 MW, which are primarily mechanical drive units. Similarly, several commenters said that EPA should provide optional concentration-based standards for all non-utility (mechanical drive) turbines; another solution would be to revise the monitoring approach to reduce cost and burden. The commenters' rationale was that mechanical drive units do not always include instruments that allow heat balance calculation of power output, and are frequently running at partial loads.

According to the commenters, a concentration-based limit would eliminate the need for variables that are difficult to accurately and readily obtain. Alternatively, these commenters felt that modifications should be made to include provisions in equation 4 of 40 CFR 60.4350(f)(3) for waste heat recovery when it is installed.

One commenter believed that limits should be specified on a concentration basis rather than on an output basis because some data show that lower concentrations can be attained at lower loads, yet, due to decreased efficiencies at lower loads, these emissions would exceed limitations on an output basis.

One commenter recommended a NO_X standard in ppm rather than an output-based standard for alternative fuels. The commenter said that in many cases, there is no demand for steam or thermal energy at or near landfills, so combined heat and power projects are unwarranted.

Response: We have considered the commenters' concerns, and have included an alternative concentration-based limit in the final rule for all turbines. Some units have difficulty with determining their power output, and adding a concentration-based emission limit significantly simplifies the regulation.

Comment: Several commenters said that turbines operating at partial load might not be able to meet the output-based limit. The commenters said that there are times when combustion turbines will run at partial load conditions, for example when a facility has not yet geared up to full production or when power is available from the grid at a lower cost than can be produced by the nonutility. According to the commenters, the turbine efficiency is lower at partial load operation, which leads to higher output-based emissions. Three commenters made the point that many combustion turbines shift out of lean premix mode into diffusion flame mode at lower loads, leading to increased NO_X emissions.

One commenter requested that the NO_X limits for partial loads be increased to account for lower thermal efficiencies at partial loads. One commenter suggested that part load operation for both gas and distillate oil revert to limits set on the basis of corrected NO_X concentrations (parts per million by volume dry (ppmvd) at 15 percent O_2). The commenter said that this coincides with operating schedules for existing General Electric dry low NO_X turbines, which are tuned to yield constant NO_X ppm throughout the operating load range. The commenter believed that this limit basis is also advantageous from the standpoint of compliance monitoring, since NO_X concentration can be measured directly on site when equipped with CEMS. Several

commenters said that the NO_X emission standards should only apply at full load, and performance testing should be conducted at 90 to 100 percent of peak load or the highest load point achievable in practice. The commenters said that if EPA does not make this change, EPA should provide data and analysis supporting the applicability of the NO_X standard at partial load outside of the typical range for manufacturer guarantees.

One commenter said that the requirement in 40 CFR 60.4400(b) of the proposed rule to perform four tests between 70 and 100 percent load seems excessive. The commenter requested that this section also clarify that the four load points should be based upon the ambient conditions and fuel characteristics realized during the time of testing, since ambient temperature can affect the maximum or minimum operating load during a given test program. The commenter noted that operating at greater than 100 percent of peak load may also be possible, especially during cold (much less than 59 °F) ambient conditions.

Response: We indicated in the final rule that the NO_X performance testing should be conducted at full load operation, which is defined as plus or minus 25 percent of 100 percent of peak load, or the highest load physically achievable in practice. Only one load point is required for testing for the annual performance test. For continuous monitoring, an alternate limit has been established when the turbine is not operating at full load. Conducting the annual test at full load is consistent with the Stationary Combustion Turbines NESHAP, 40 CFR part 63, subpart YYYY.

Comment: Several commenters requested that EPA specify that the emission standards only apply for ambient temperatures ranging from 0 to 100 °F. Alternatively, the commenters asked EPA to provide data and analysis supporting the applicability of the NO_X standard at ambient temperatures outside of the typical range for manufacturer guarantees. Two commenters said that NO_X is higher at lower ambient temperatures, efficiencies are compromised at lower ambient temperatures, and cold intake air causes flame stability issues. The commenters also noted that EPA data in Alaska does not cover the winter operating season. The commenter provided some plots of emissions data for operations at low temperatures.

Response: EPA concluded that turbines do not operate optimally at ambient temperatures below 0 °F. Therefore, compliance demonstrations, such as annual testing, are required at ambient temperatures greater than 0 °F in the final rule. If you are using a CEMS for demonstrating compliance, alternate emissions standards apply when the ambient temperature is below 0 °F. We recognize that these temperatures may increase emissions from the turbine.

Comment: A number of commenters had concerns with the efficiencies that EPA used to determine the values for the output-based emission standards. One commenter stated that if EPA retained an output-based NO_X standard for units less than 30 MW, EPA should revise the efficiency basis for the standard, which is not supported by the docket material for industrial scale units. Three commenters said that the proposed NO_X emission standards needed to be revised to reflect the full range of turbine efficiencies that may be encountered during operation. Three commenters said that during the first 5 years of operation, the maximum load that can be achieved can decrease by as much as 5 percent while the thermal efficiency can decrease by as much as 2.5 percent.

One commenter said that 30 percent efficiency is not consistently achieved for small simple cycle turbines. The commenter recommended using 23 percent efficiency (LHV) at full load for turbines less than 3.5 MW, and 25 percent efficiency (LHV) at full load for the 3.5–30 MW turbines, to ensure that smaller turbines can achieve the NSPS at site conditions, which provide variability in efficiency.

Four commenters observed that the efficiencies on which the proposed output-based emissions were based only apply at full loads. One commenter said that the *Gas Turbine World* specifications show more than half of all models less than 30 MW have efficiencies lower than 30 percent. The commenter also said that lower loads have lower efficiencies, also many combined cycle units have efficiencies less than what EPA assumes. Another commenter asserted that EPA's standard is based on stack tests, conducted at steady state, so efficiency losses associated with changing load are not captured. In addition, the commenter believed that these efficiencies are only for "out of the box" turbines.

Two commenters said that EPA determined the 30 percent value based on turbine efficiency data in *Gas Turbine World*, which is based on LHV, but the commenters believed that EPA may have applied it inappropriately, as if it were HHV. If EPA had intended to base the efficiency assumption on HHV, it appears that the limit for turbines less than 30 MW was rounded down from 1.046 to 1.0 lb/MWh, according to the commenters. But if EPA intended to base the efficiency assumption on LHV, then the commenters determined that the limit should be 1.147 lb/MWh. The commenters said that even if EPA had intended the HHV efficiency, the rounding difference is almost 5 percent for the smaller turbine category, and this could be significant for turbines just meeting the 25 ppmv vendor guarantee.

Response: We developed alternative concentration-based standards, so that efficiency is no longer an issue if this alternative is chosen. In the final rule, we used a baseline efficiency of 23 percent for small turbines, 27 percent for medium turbines, and 44 percent for large turbines. The small turbine efficiency is based on the 40 CFR part 60, subpart GG, lowest efficiency, 25 percent based on LHV. The medium turbine efficiency is based on the top 90 percent of the medium turbine efficiencies listed in the 2005 Global Sourcing Guide for Gas Turbine Engines (*http://www.dieselpub.com/gsg*). The large turbine efficiency is based on the top 90 percent of the combined cycle efficiencies listed in the 2005 Global Sourcing Guide for Gas Turbine Engines. EPA concluded that these efficiencies are appropriate for turbines that elect to comply with the output-based standard.

Comment: Several commenters strongly opposed the NO_X emission limits established in the rule, as proposed. They contended that EPA's basis for establishing the limits was fundamentally flawed and not representative of current combustion turbines without the use of add-on controls. The commenters said that the proposed limits have no support in the docket's actual test data, and are the product of generalizations and faulty assumptions about the data, and must be withdrawn until they can be properly based on the data they cite.

According to the commenters, over 35 percent of the reported emission rates from natural gas-fired units and nearly all of those from fuel oil-fired units exceed the proposed output-based limits. Other concerns with the data expressed by the commenters included: Some power ranges are insufficiently represented because there are no data between 80 and 150 MW and there are few data over 160 MW; aeroderivative turbines are underrepresented; there were no useable emission rate data for several manufacturers; and EPA did not consider variability in load and may not have had adequate data for low temperatures. Another commenter believed that EPA did not heed the recommendations of the Gas Turbine

Association in their November 11, 2004, memorandum. In addition, this commenter believed that EPA did not match the population percentages to the data they reviewed. For example, the commenter said that almost 68 percent of the recent turbine orders are in the small category, yet only 21 percent of the data reviewed by EPA were in this subcategory. Additionally, the commenter said that for this subcategory, the maximum NO_X emission concentration listed is 27.8 ppm, which is above the level of 25 ppm used in proposing the standard for the small subcategory.

Many of the commenters provided suggested NO_X emission standards to EPA.

Response: While not all turbine models were represented in the data set, we concluded that it is representative of today's population of turbines. In addition, we obtained more data during the comment period, including emissions information for turbines less than 50 MMBtu/h. Also, our analysis included the addition of manufacturer guarantees and permit information, which, along with emissions data, gave us a clear picture of the achievability of the standards. The emission limits in the final rule have been revised, as appropriate, using these additional data and information. See table 1 of this preamble for the revised emission standards.

Comment: One commenter believed that there is a significant difference between aeroderivative turbines and frame type turbines in that aeroderivatives cannot employ low NO_X burners and must use water injection. While aeroderivatives may be guaranteed by the manufacturer to achieve 25 ppm at full load, the commenter believed that setting a standard at that level affords no cushion for operation below full load, especially in light of the short averaging times. Therefore, the commenter requested that EPA either raise the emission limit to allow for operational flexibility, or set different standards for different types of combustion turbines.

Response: We concluded that the majority of turbines are in some manner related to jet engine designs. The combustion turbine industry began in the aviation industry, and we concluded that it is not appropriate to subcategorize turbines based on design characteristics. The primary difference is the degree to which the turbines have been optimized for stationary applications. Furthermore, EPA concluded that there is no appropriate definition that separates aeroderivative and frame turbines.

In the final rule we increased the upper limit on the medium turbine category to 850 MMBtu/h. The medium turbine category covers the majority of turbines that the comments addressed. This category is based on the heat input to a 44 percent efficient 110 MW turbine. The standards in the final rule address the commenter's concerns.

Comment: Four commenters suggested emission limits for small turbines. One commenter recommended a fuel neutral standard of 150 ppmv for turbines less than 3 MW. Another commenter recommended a NO_X standard of 100 ppmv for natural gas-fired turbines less than 3 MW, and 150 ppmv for distillate oil-fired turbines less than 3 MW. One commenter said that if EPA retains turbines less than 3.5 MW in 40 CFR part 60, subpart KKKK, the NO_X emission limit for new construction should be 100 ppmv for natural gas and 175 ppmv for distillate oil; for modified or reconstructed turbines, the NO_X emission limit should be 150 ppmv for natural gas and 200 ppmv for distillate oil. The commenter recommended a concentration limit for mechanical drive turbines and an output-based limit based on an efficiency of 23 percent for power generators. Another commenter stated that if EPA retains turbines less than 3.5 MW in 40 CFR part 60, subpart KKKK, the NO_X emission limit for turbines between 1 and 3.5 MW should be no more stringent than 6 lb/MWh for natural gas, distillate oil and other fuels. The commenter's rationale was that this level is comparable to 40 CFR part 60, subpart GG, and significant improvements in control technologies have not been made since subpart GG was established.

Response: Based on the comments received, we revised the emission limitations in the final rule for small turbines, as shown in table 1 of this preamble. We received additional data from the turbine manufacturer for small turbines. Based on these data, we concluded that the majority of small turbines will be able to comply with the revised emission limitations given in the final rule. These numbers were based on data received from small turbine manufacturers during the public comment period.

Comment: Six commenters believed that the NO_X standards for turbines less than 30 MW were not consistently achievable in practice. Two of the commenters said that the standard for natural gas turbines 3 to 30 MW should be 42 ppmv. One commenter said that the standard for natural gas turbines 3.5 to 30 MW should be 42 ppmv for mechanical drive units, and based on 42 ppmv with an efficiency of 25 percent for power generation units. For distillate oil turbines 3.5 to 30 MW, the commenter said that the NO_X standard should be 96 ppmv for mechanical drive units, and based on 96 ppmv with an efficiency of 25 percent for power generation units. One commenter recommended a standard of 100 ppmv for oil-fired turbines. Three commenters suggested that EPA provide an option to pursue an alternative emission limit for retrofit applications that do not offer a 42 ppmv NO_X guarantee.

One commenter said that for turbines under 30 MW, a NO_X standard of 1.0 lb/MWh will be too stringent for some projects, particularly the smaller (less than 3.5 MW) facilities. The commenter believed that this will prevent the implementation of some projects that could provide lower emissions than the generation sources they are displacing. The commenter suggested that the limit should be no more stringent than 1.4 lb/MWh (25 ppm at 25 percent efficiency, LHV) for natural gas-fired turbines.

One commenter did not believe that any turbines less than 30 MW could meet the proposed emission limits. The commenter said that peaking turbines would not be able to meet the emission limits because they must operate at variable loads and also low temperatures increase NO_X emissions. The commenter believed that even at full load and 60 °F ambient temperature, a dry low NO_X turbine would just barely make the NO_X limit. Therefore, the commenter suggested that EPA increase the limit in combination with defining a limited range over which the limit is applicable. The commenter also noted that SCR has only been installed in a handful of simple cycle units and high temperature SCR is less reliable than standard SCR.

Response: We revised the emission limitations as well as the subcategory for medium turbines, as presented in table 1 of this preamble. The medium subcategory has been extended to cover additional turbines. The new subcategory on which these comments are based is from 50 MMBtu/h to 850 MMBtu/h. We concluded that, based on data submitted during the comment period, the new emission limitations in the final rule are achievable by most turbines in this subcategory without the use of add-on controls.

Comment: Several commenters said that the proposed NO_X limits for oil-fired units were too low. One commenter said that EPA's proposed output-based limits for oil-fired units cannot be achieved on simple cycle turbines with combustion controls. The commenter felt that the limit for oil-

fired turbines, 1.2 lb/MWh, is de facto too stringent, and imposing an efficiency of 48 percent would be arbitrary and capricious. The commenter requested that EPA separate simple cycle from combined cycle, particularly for oil-fired units. One commenter requested that EPA either raise the emission limit for oil-fired combustion turbines, or at least allow large oil-fired peaking units to comply with the emission limit for small oil-fired units. Many of the commenters provided suggested emission levels for oil-fired units to EPA.

Response: EPA concluded that, based on data submitted during the comment period, the new emission limitations in the final rule for oil-fired turbines are achievable by most turbines without the use of add-on controls.

C. Definitions

Comment: Four commenters requested that EPA clarify the definition of efficiency. The commenters stated that the proposed definition is based on the LHV, but that EPA usually defines regulations based on HHV. The commenters believed that EPA may have intended to use HHV and requested clarification on whether efficiency should be based on the LHV or the HHV. One commenter stated that the LHV clause is unnecessary and should be removed because most air permits are written, modeled and reviewed upon the premise of the HHV of the fuel.

Response: In the proposed rule, we inadvertently defined efficiency in terms of LHV. Our intent was to use HHV. This change is reflected in the final rule.

V. Environmental and Economic Impacts

A. What are the air impacts?

We estimate that approximately 355 new stationary combustion turbines will be installed in the United States over the next 5 years and affected by the final rule. None of these units may need to install add-on controls to meet the NO_X limits required under the final rule. However, many new turbines will already be required to install add-on controls to meet NO_X reduction requirements under Prevention of Significant Deterioration (PSD) and New Source Review (NSR). Thus, we concluded that the NO_X reductions resulting from the final rule will essentially be zero. The expected SO2 reductions as a result of the final rule are approximately 830 tons per year (tpy) in the 5th year after promulgation of the standards.

Although we expect the final rule to result in a slight increase in electrical supply generated by unaffected sources (e.g., existing stationary combustion turbines), we concluded that this will not result in higher NO_X and SO_2 emissions from these sources. Other emission control programs such as the Acid Rain Program and PSD/NSR already promote or require emission controls that would effectively prevent emissions from increasing. All the emissions reductions estimates and assumptions have been documented in the docket to the final rule.

B. What are the energy impacts?

We do not expect any significant energy impacts resulting from the final rule. The only energy requirement is a potential small increase in fuel consumption, resulting from back pressure caused by operating an add-on emission control device, such as an SCR. However, most entities would be able to comply with the final rule without the use of any add-on control devices.

C. What are the economic impacts?

EPA prepared an economic impact analysis to evaluate the impacts the final rule would have on combustion turbines producers, consumers of goods and services produced by combustion turbines, and society. The analysis showed minimal changes in prices and output for products made by the industries affected by the final rule. The price increase for affected output is less than 0.003 percent, and the reduction in output is less than 0.003 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.01 percent for petroleum products and natural gas, and price increases of 0.04 and 0.06 percent for base-load and peak-load electricity, respectively. The price of coal is expected to decline by about 0.002 percent, and that is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.02 percent for each energy type, including base-load and peak-load electricity.

The social costs of the final rule are estimated at $0.4 million (2002 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. For the final rule, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the rule lead to the estimated social costs being less than the total annualized compliance cost estimate of $3.4 million (2002 dollars). The primary reason for the lower social cost estimate is the increase in electricity supply generated by unaffected sources (e.g., existing stationary combustion turbines), which offsets mostly the impact of increased electricity prices to consumers. The social cost estimates discussed above do not account for any benefits from emission reductions associated with the final rule.

For more information on these impacts, please refer to the economic impact analysis in the public docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

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

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to OMB under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned ICR No. 2177.01.

The final rule contains monitoring, reporting, and recordkeeping requirements. The information would be used by EPA to identify any new, modified, or reconstructed stationary combustion turbines subject to the NSPS and to ensure that any new stationary combustion turbines comply with the emission limits and other requirements. Records and reports would be necessary to enable EPA or States to identify new stationary combustion turbines that may not be in compliance with the requirements. Based on reported information, EPA would decide which units and what records or processes should be inspected.

The final rule does not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after July 6, 2006) is estimated to be 20,542 labor hours per year at an average total annual cost of $1,797,264. This estimate includes performance testing, continuous monitoring, semiannual excess emission reports, notifications, and recordkeeping. There are no capital/start-up costs or operation and maintenance costs associated with the monitoring requirements over the 3-year period of the ICR.

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

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of today's final rule on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, depending on size definition for the affected North American Industry Classification System (NAICS) code, or fewer than 4 billion kilowatt-hours (kW-hr) per year of electricity usage; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. It should be noted that small entities in one NAICS code would be affected by the final rule, and the small business definition applied to each industry by NAICS code is that listed in the Small Business Administration size standards (13 CFR part 121).

After considering the economic impacts of today's final rule on small entities, we conclude that today's action will not have a significant economic impact on a substantial number of small entities. We determined, based on the existing combustion turbines inventory and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new turbines in the 5th year after promulgation, that one small entity out of 29 in the industries impacted by the final rule will incur compliance costs (in this case, only monitoring, recordkeeping, and reporting costs since control costs are zero) associated with the final rule. This small entity owns one affected turbine in the projected set of new combustion turbines. This affected small entity is estimated to have annual compliance costs of 0.3 percent of its revenues. The final rule is likely to also increase profits for the small firms and increase revenues for the many small communities (in total, 28 small entities) using combustion turbines that are not affected by the final rule as a result of the very slight increase in market prices. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the final rule on small entities. In the final rule, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. In addition, as mentioned earlier in this preamble, new turbines with heat inputs less than 10.7 GJ (10 MMBtu) per hour are not subject to the final rule. This provision should reduce the size of small entity impacts. We continue to be interested in the potential impacts of the final rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed

under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final rule contains no Federal mandates that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, the final rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or impose obligations upon them. Therefore, the final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

The final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to the final rule.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes."

The final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. We do not know of any stationary combustion turbines owned or operated by Indian tribal governments. However, if there are any, the effect of the final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to the final rule.

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

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

The final rule is not subject to Executive Order 13045 because it is not an economically significant action as defined under Executive Order 12866.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Today's action is not a "significant energy action" as defined in Executive Order 13211 because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

An increase in petroleum product output, which includes increases in fuel production, is estimated at less than 0.01 percent, or about 600 barrels per day based on 2004 U.S. fuel production nationwide. A reduction in coal production is estimated at 0.00003 percent, or about 3,000 short tpy based on 2004 U.S. coal production nationwide. The reduction in electricity output is estimated at 0.02 percent, or about 5 billion kW-hr per year based on 2000 U.S. electricity production nationwide.

Production of natural gas is expected to increase by 4 million cubic feet per day. The maximum of all energy price increases, which include increases in natural gas prices as well as those for petroleum products, coal, and electricity, is estimated to be a 0.04 percent increase in peak-load electricity rates nationwide. Energy distribution costs may increase by no more than the same amount as electricity rates. We expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies.

Also, the increase in the cost of energy production should be minimal given the very small increase in fuel consumption resulting from back pressure related to operation of add-on emission control devices, such as SCR. All of the estimates presented above account for some passthrough of costs to consumers as well as the direct cost impact to producers.

For more information on these estimated energy effects, please refer to the economic impact analysis for the final rule. This analysis is available in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

The final rule involves technical standards. EPA cites the following methods in the final rule: EPA Methods 1, 2, 3A, 6, 6C, 7E, 8, 19, and 20 of 40 CFR part 60, appendix A; and Performance Specifications (PS) 2 of 40 CFR part 60, appendix B.

In addition, the final rule cites the following standards that are also incorporated by reference in 40 CFR part 60, section 17: ASTM D129–00

(Reapproved 2005), ASTM D1072–90 (Reapproved 1999), ASTM D1266 98 (Reapproved 2003), ASTM D1552–03, ASTM D2622–05, ASTM D3246–05, ASTM D4057–95 (Reapproved 2000), ASTM D4084–05, ASTM D4177–95 (Reapproved 2000), ASTM D4294–03, ASTM D4468–85 (Reapproved 2000), ASTM D4810–88 (Reapproved 1999), ASTM D5287–97 (Reapproved 2002), ASTM D5453–05, ASTM D5504–01, ASTM D6228–98 (Reapproved 2003), ASTM D6667–04, and Gas Processors Association Standard 2377–86.

Consistent with the NTTAA, EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods/performance specifications. No applicable voluntary consensus standards were identified for EPA Methods 8 and 19. The search and review results have been documented and are placed in the docket for the final rule.

One voluntary consensus standard was identified as an acceptable alternative for the EPA methods cited in this rule. The voluntary consensus standard ASME PTC 19–10–1981—Part 10, "Flue and Exhaust Gas Analyses," is cited in this rule for its manual method for measuring the sulfur dioxide content of exhaust gas. This part of ASME PTC 19–10–1981—Part 10 is an acceptable alternative to EPA Methods 6 and 20 (sulfur dioxide only).

In addition to the voluntary consensus standards EPA uses in the final rule, the search for emissions measurement procedures identified 11 other voluntary consensus standards. EPA determined that nine of these 11 standards identified for measuring air emissions or surrogates subject to emission standards in the final rule were impractical alternatives to EPA test methods/performance specifications for the purposes of the final rule. Therefore, EPA does not intend to adopt these standards. See the docket for the reasons for the determinations of these methods.

Two of the 11 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body. See the docket for the list of these methods.

Sections 60.4345, 60.4360, 60.4400 and 60.4415 of the final rule discuss EPA testing methods, performance specifications, and procedures required. Under 40 CFR 63.7(f) and 40 CFR 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of EPA testing methods, performance specifications, or procedures.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. section 801 *et. seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing today's final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on July 6, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: February 9, 2006.

Stephen L. Johnson,

Administrator.

Editorial Note: This document was received by the Office of the Federal Register on June 28, 2006.

■ For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of Federal Regulations is amended as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended by revising paragraphs (a), (h)(4), and (m)(1), and reserving paragraph (m)(2) to read as follows:

§ 60.17 Incorporation by reference.

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for § 60.261.

(2) ASTM A100–69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(3) ASTM A101–73, 93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(4) ASTM A482–76, 93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(5) ASTM A483–64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(6) ASTM A495–76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), and 60.633(h).

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.

(9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a)(1)(i).

(10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.

(11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(13) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41(f) of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.251(b) and (c) of subpart Y of this part.

(14) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004) $^{\varepsilon 1}$, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.24(h)(8), 60.41Da of subpart Da of this part, and 60.4102.

(15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils,

IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.

(16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.

(17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b)(10)(ii).

(18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a)(1)(ii).

(19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f)(5)(i).

(20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(22) ASTM D1266–98 (Reapproved 2003) ε^1, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a)(1)(i).

(23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

(25) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a)(1)(i).

(26) ASTM D1826–77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.

(27) ASTM D1835–87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41Da of subpart Da of this part.

(28) ASTM D1835–82, 86, 87, 91, 97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41b of subpart Db of this part.

(29) ASTM D1835–86, 87, 91, 97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for § 60.41c of subpart Dc of this part.

(30) ASTM D1945–64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f)(5)(i).

(31) ASTM D1946–77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).

(32) ASTM D2013–72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(33) ASTM D2015–77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(34) ASTM D2016–74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.

(35) ASTM D2234–76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.

(36) ASTM D2369–81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.

(37) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(38) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for § 60.485(g)(5).

(39) ASTM D2584–68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c)(3)(i).

(40) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b)(9)(i).

(41) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry," IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(42) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry," IBR approved for § 60.4415(a)(1)(i).

(43) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), and 60.485(e)(1).

(44) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(45) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(46) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(47) ASTM D3173–73, 87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(48) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.

(49) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(50) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f)(5)(i).

(51) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b)(10)(ii).

(52) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1)(ii).

(53) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.

(54) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(55) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(56) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.

(57) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.

(58) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.

(59) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(60) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h)(1).

(61) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(62) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(63) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(64) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(65) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b)(10)(i).

(66) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a)(1)(i).

(67) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.

(68) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.

(69) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.

(70) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b)(10)(ii) and 60.4415(a)(1)(ii).

(71) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for § 60.335(b)(9)(i).

(72) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

(73) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(74) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a)(1).

(75) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.

(76) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(i).

(77) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(i).

(78) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h)(1) and 60.4360.

(79) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b)(9)(i).

(80) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(81) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.

(82) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h)(1).

(83) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

(84) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9)(i).

(85) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(86) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(ii).

(87) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(ii).

(88) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B

to part 60, Performance Specification 12A, Section 8.6.2.

(89) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(90) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(91) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.593(b)(2) and 60.632(f).

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, and §§ 60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

* * * * *

(m) * * *

(1) Gas Processors Association Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§ 60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

(2) [Reserved]

■ 3. Part 60 is amended by reserving subpart IIII and subpart JJJJ and by adding subpart KKKK to read as follows:

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Introduction

Applicability

Emission Limits

General Compliance Requirements

Monitoring

Reporting

Performance Tests

Definitions

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with § 60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass

emissions methodology in § 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in § 75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in § 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad \text{(Eq. 4)}$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in § 75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the

associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with § 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or

ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \quad \text{(Eq. 5)}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see § 60.17) for natural gas or ASTM D4177 (incorporated by reference, see § 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see § 60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see § 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see § 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in § 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a

combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

TABLE 1.—TO SUBPART KKKK OF PART 60.—NITROGEN OXIDE EMISSION LIMITS FOR NEW STATIONARY COMBUSTION TURBINES

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_x emission standard
New turbine firing natural gas, electric generating.	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas ..	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).

TABLE 1.—TO SUBPART KKKK OF PART 60.—NITROGEN OXIDE EMISSION LIMITS FOR NEW STATIONARY COMBUSTION TURBINES—Continued

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

[FR Doc. 06–5945 Filed 7–5–06; 8:45 am]
BILLING CODE 6560–50–P

A. Attendance

The seminars are open to all interested parties. Metal and nonmetal mine operators, including contractors, who use diesel-powered equipment underground, as well as miners who work at those operations, miners' representatives and diesel powered equipment manufacturers are encouraged to attend the seminars. Registration to attend the seminars is not required.

B. Conduct of the Seminars

The seminars will begin each day at 9 a.m. During the morning session, MSHA will answer questions about requirements of the rule including compliance determination, the final PELs, applications for extensions of time in which to meet the final limits, medical evaluation, and transfer provisions. MSHA will give a PowerPoint presentation of the final rule provisions, followed by a question and answer session with the attendees.

The afternoon session will focus on a discussion of control technology. The purpose of the controls session is to provide the mining community with technical information on DPM control technologies that can be used to reduce personal exposures to DPM in underground MNM mines. The PowerPoint presentations will be made available on MSHA's Internet site at *http://www.msha.gov.*

C. Location of Seminars

The seminars will be held on the following dates and at the locations indicated:

Date	Location	Phone
June 27, 2006	Pittsburgh Airport Marriott, 777 Aten Road, Coraopolis, PA 15108	(800) 328–9297
June 29, 2006	Executive Inn, 978 Phillips Lane, Louisville, KY 40213	(800) 626–2706
July 13, 2006	Reno Sparks Convention Center, 4590 S Virginia Street, Reno, NV 89502–6013	(775) 827–7620

The Reno, NV seminar is being held in conjunction with the National Metal and Nonmetal Mine Rescue Contest and is at the same location as the contest.

II. Background

In January 2001, MSHA promulgated a final rule addressing DPM exposure of underground metal and nonmetal miners (66 FR 5706). The 2001 final rule established new health standards for underground metal and nonmetal mines that use equipment powered by diesel engines. The rule established an interim concentration limit of 400 micrograms of total carbon (TC) per cubic meter of air (400_{TC} µg/m³) which became applicable July 20, 2002, and a final concentration limit of 160 micrograms of total carbon per cubic meter of air (160_{TC} µg/m³) to become applicable after January 19, 2006; (amended on September 19, 2005 (70 FR 55019), to become applicable May 20, 2006). Industry challenged the rule and organized labor intervened in the litigation. Settlement negotiations with the litigants have resulted in other regulatory actions on several requirements of the rule. On February 27, 2002 (67 FR 9180), MSHA revised the 2001 final rule to clarify § 57.5060(b)(1) and (b)(2) regarding maintenance and to add a new paragraph (b)(3) to § 57.5067 regarding the transfer of existing equipment between underground mines. MSHA published the 2005 final rule on June 6, 2005, which converted the interim concentration limit measured by TC to a comparable permissible exposure limit (PEL) measured by elemental carbon (EC).

The 2006 final rule phases in the DPM final limit of 160_{TC} µg/m³ over a two-year period, based on feasibility. On May 20, 2006, the first phase of the final limit of 308_{EC} µg/m³ became effective. On January 20, 2007, the DPM final limit will be reduced to 350_{TC} µg/m³. The final limit of 160_{TC} µg/m³ will become effective on May 20, 2008. Mine operators must continue to use engineering and administrative controls, supplemented by respiratory protection when needed, to reduce miners' exposures to the prescribed limits. As with the interim DPM limit, MSHA will enforce the final limits as permissible exposure limits (PEL).

This final rule also establishes new requirements for medical evaluation of miners required to wear respiratory protection, and transfer of miners who are medically unable to wear a respirator. It deletes the existing provision that restricts newer mines from applying for an extension of time in which to meet the final limit.

Dated: June 6, 2006.

Patricia W. Silvey,

Acting Director, Office of Standards, Regulations and Variances.

[FR Doc. E6–9067 Filed 6–8–06; 8:45 am]

BILLING CODE 4510–43–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2002–0056; FRL–8180–4]

RIN 2060–AN50

Revision of December 2000 Clean Air Act Section 112(n) Finding Regarding Electric Utility Steam Generating Units; and Standards of Performance for New and Existing Electric Utility Steam Generating Units: Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: This action sets forth EPA's decision after reconsidering certain aspects of the March 29, 2005 final rule entitled "Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from the Section 112(c) List" (Section 112(n) Revision Rule). We are also issuing our final decision regarding reconsideration of certain issues in the May 18, 2005 final rule entitled "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" (Clean Air Mercury Rule; CAMR).

After considering the petitions for reconsideration and the comments received, we are not revising the final Section 112(n) Revision Rule other than explaining in more detail what we meant by the effectiveness element in the term "necessary." The only two substantive changes we are making to

CAMR in response to comments involve revisions to the State mercury (Hg) allocations, and to the new source performance standards (NSPS). We also are finalizing the regulatory text that clarifies the applicability of CAMR to municipal waste combusters (MWC) and certain industrial boilers. Finally, we are denying the requests for reconsideration with respect to all other issues raised in the petitions for reconsideration submitted for both rules.

DATES: *Effective Date:* This final action is effective on June 9, 2006.

ADDRESSES: *Docket.* EPA has established a docket for this action including Docket ID No. EPA–HQ–OAR–2002–0056, legacy EDOCKET ID No. OAR–2002–0056, and legacy Docket ID No. A–92–55. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the following address: Air and Radiation Docket and Information Center (Air Docket), EPA/DC, EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The Docket telephone number is (202) 566–1744. The Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For general and technical information, contact Mr. William Maxwell, Emission Strategies Group, Sector Policies and Programs Division, Mailcode: D243–01, U.S. EPA, Research Triangle Park, NC 27711; telephone number: (919) 541–5430; fax number: (919) 541–5450; e-mail address: *maxwell.bill@epa.gov.*

SUPPLEMENTARY INFORMATION:

Outline. The information presented in this preamble is organized as follows:

I. General Information

A. Does this reconsideration action apply to me?

Categories and entities potentially affected by this action include:

Category	NAICS code[1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal Government	[2]221122	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal Government	[2]221122	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. This table lists examples of the types of entities EPA is now aware could potentially be affected by this action. Other types of entities not listed could also be affected. If you have questions regarding the applicability of this action to a particular entity, consult Mr. William Maxwell listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action also will be available on the World Wide Web (WWW) through EPA's Technology Transfer Network (TTN). Following the Administrator's signature, a copy of this action will be posted on the TTN's policy and guidance page for newly proposed rules at *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

C. Is this action subject to judicial review?

Under section 307(b) of the Clean Air Act (CAA or the Act), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit on or before August 8, 2006. Only those objections to the final action which were raised with reasonable specificity during the period for public comment may be raised during judicial review. Moreover, under CAA section 307(b)(2), the requirements established by this final action may not be challenged separately in any civil or criminal proceeding we bring to enforce these requirements.

II. Background

For a brief history of the Section 112(n) Revision Rule rulemaking process that preceded this final action, see our discussion at 70 FR 62200 (October 28, 2005). On March 29, 2005, we issued a final rule (70 FR 15994) that revised the Agency's December 2000 finding made pursuant to CAA section 112(n)(1)(A), and based on that revision, removed coal- and oil-fired electric utility steam generating units (Utility Units or power plants) from the CAA section 112(c) source category list.

Following publication of the March 29, 2005 **Federal Register** rule, the Administrator received two petitions, filed pursuant to section 307(d)(7)(B) of the CAA, requesting reconsideration of

many aspects of the final rule.[1] On October 28, 2005 (70 FR 62200), we granted reconsideration on several issues raised by petitioners (October Reconsideration Notice).[2] At that time, we did not act on any of the remaining issues in those petitions. We are responding to those issues in this action.

The issues on which we granted reconsideration involved several aspects of the final rule, including:

- Legal interpretations;
- EPA's methodology and conclusions concerning why utility Hg emissions remaining after imposition of the requirements of the CAA are not reasonably anticipated to result in hazards to public health;
- Detailed discussion of certain issues related to coal-fired Utility Units as set forth in section VI of the final Section 112(n) Revision Rule; and
- EPA's decision related to nickel (Ni) emissions from oil-fired Utility Units.

We describe these issues at 70 FR 62200. For the reasons indicated in a letter dated June 24, 2005, we denied petitioners request that we administratively stay the Section 112(n) Revision Rule under CAA section 307(d)(7)(B). On August 4, 2005, the D.C. Circuit denied a similar request to stay the Section 112(n) Revision Rule pending the outcome of the litigation challenging the rule.

For a brief history of the CAMR rulemaking process that preceded this final action, see our discussion at 70 FR 62213 (October 28, 2005). On May 18, 2005, we issued a final rule (70 FR 28606) that established standards of performance for emissions of Hg from new and existing, coal-fired electric utility steam generating units (Utility Units or EGU). Following publication of the May 18, 2005 **Federal Register** rule the Administrator received four petitions, filed pursuant to CAA section 307(d)(7)(B), requesting reconsideration of many aspects of the final rule.[3]

On October 28, 2005 (70 FR 62213), we granted reconsideration on seven issues raised by petitioners. At that time, we did not act on any of the remaining issues in those petitions. We are responding to those issues in this action.

The issues on which we granted reconsideration involved seven narrow aspects of the final rule as follows:

- 2010 phase I Statewide Hg emission budgets and the unit-level Hg emission allocations on which those budgets are based;
- Definition of "designated pollutant" under 40 CFR 60.21;
- EPA's subcategorization for subbituminous coal-fired units in the context of the new source performance standards (NSPS);
- Statistical analysis used for the NSPS;
- Hg content in coal used to derive the NSPS;
- Definition of covered units as including municipal waste combustors (MWC); and,
- Definition of covered units as including some industrial boilers.

We describe these issues at 70 FR 62213. For the reasons indicated in a letter dated August 19, 2005, we denied petitioners request that we administratively stay CAMR under CAA section 307(d)(7)(B).

On November 17, 2005, we held a public hearing on the issues for which we granted reconsideration under all six petitions. Five individuals gave oral presentations at the hearing. The transcript of their comments is located in Docket EPA–HQ–OAR–2002–0056, which can be accessed on the Internet at *http://www.regulations.gov.*

We provided a public comment period on the reconsideration issues that ended on December 19, 2005. More than 300 written public comments on the reconsideration issues were received (for both the Section 112(n) Revision Rule and CAMR). The individual comment letters can be found in Docket EPA–HQ–OAR–2002–0056.

III. This Action

We are making available in Docket EPA–HQ–OAR–2002–0056 a document entitled, "Response to Significant Public Comments Received in Response to: Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from the Section 112(c) List: Reconsideration (70 FR 62200; October 28, 2005) and Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units: Reconsideration (70 FR 62213; October 28, 2005)," (Final Reconsideration Response to Comment Document, RTC). This document contains (1) a summary of the comments received on the issues for which we granted reconsideration and our responses to these comments, and (2) a summary of issues raised in the petitions for which we are denying reconsideration, and our rationale for denying reconsideration. This document is available on our Web site at *http://www.epa.gov/ttn/atw/utility/utiltoxpg.html* and through the docket at *http://www.regulations.gov.*

A. Section 112(n) Revision Rule

In the final Section 112(n) Revision Rule, EPA revised the regulatory finding that it issued in December 2000 pursuant to section 112(n)(1)(A) of the CAA, and based on that revision, removed coal- and oil-fired electric utility steam generating units (coal- and oil-fired Utility Units) from the CAA section 112(c) source category list.

At this time, we are announcing our final action after reconsideration of several aspects of the Section 112(n) Revision Rule. We are also announcing our final decision on reconsideration of the remaining issues that were raised by the petitioners.

1. Issues for Which We Granted Reconsideration

After carefully considering the petitions and the information that was submitted during the public comment period, we have determined that none of the new information presented leads us to conclude that our original determination as presented in the final Section 112(n) Revision Rule was incorrect. Therefore, we are reaffirming the March 29, 2005 action. A summary of the comments received and our responses to these comments can be found in our Final Reconsideration RTC. A short summary of the final 112(n) decision follows:

a. *Legal Interpretations.* Congress treated Utility Units differently from other major and area sources and provided EPA considerable discretion in determining whether to regulate such

[1] One petition was submitted by 14 States: New Jersey, California, Connecticut, Delaware, Illinois, Maine, Massachusetts, New Hampshire, New Mexico, New York, Pennsylvania, Rhode Island, Vermont, and Wisconsin (State petitioners). The other petition was submitted by five environmental groups and four Indian Tribes: The Natural Resources Defense Council (NRDC), the Clean Air Task Force (CATF), the Ohio Environmental Council, the U.S. Public Interest Research Group (USPIRG), the Natural Resources Council of Maine; the Aroostook Band of Micmacs, the Houlton Band of Maliseet Indians, the Penobscot Indian Nation, and the Passamaquoddy Tribe of Maine (Indian Township and Pleasant Point) (Environmental petitioners).

[2] In this action, the term "petitioner" refers only to those entities that filed petitions for reconsideration.

[3] One petition was submitted by 14 States: New Jersey, California, Connecticut, Delaware, Illinois, Maine, Massachusetts, New Hampshire, New Mexico, New York, Pennsylvania, Rhode Island, Vermont, and Wisconsin (State petitioners). The second petition was submitted by five environmental groups: the Natural Resources Defense Council (NRDC), the Clean Air Task Force (CATF), the Ohio Environmental Council, the U.S. Public Interest Research Group (USPIRG), and the Natural Resources Council of Maine. The third petition was submitted by the Jamestown Board of Public Utilities. The fourth petition was submitted by the Integrated Waste Service Association (IWSA).

units under CAA section 112. CAA section 112(n)(1)(A) provides:

> The Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) of this section after imposition of the requirements of this Act. The Administrator shall report the results of this study to the Congress within 3 years after November 15, 1990. The Administrator shall develop and describe in the Administrator's report to Congress alternative control strategies for emissions which may warrant regulation under this section. The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph.

The rationale behind our interpretation of the above language is set forth in the final Section 112(n) Revision Rule, the Reconsideration Notice, and attendant response to comment documents. *See, e.g.,* 70 FR 15997–16002; Final Reconsideration RTC; Section 1.1.1. In those documents we explain how we reasonably interpreted the terms "appropriate" and "necessary," as well as why it was reasonable for us to interpret CAA section 112(n)(1)(A) to focus on (1) hazards to public health and (2) hazardous air pollutant (HAP) emissions from Utility Units remaining after imposition of the requirements of the Act when making our appropriate and necessary inquiries. Although in this action we are not reiterating all the reasons our interpretations are reasonable, we note that the comments received during reconsideration did not cause us to change those interpretations.

We are, however, clarifying what we meant when we said that the "necessary" inquiry entails an analysis of whether the alternative authorities identified under the Act would "effectively address" the remaining HAP emissions from Utility Units. *See* 70 FR 16001. In interpreting the phrase "necessary" to incorporate an effectiveness inquiry, we did not intend for such an inquiry to involve a public health-based assessment, or "health test," as some commenters called it. Rather, the sole purpose of including the effectiveness inquiry as part of the "necessary" analysis was to ensure that EPA was not precluded from regulating Utility Units under CAA section 112 where another statutory authority identified would do so in a manner that was either not cost-effective or administratively effective in terms of ease of implementation of the program for regulators and the regulated community (even though that statutory authority may address any remaining hazards to public health).

To summarize, there are two aspects of the "necessary" inquiry. The first aspect involves a determination as to whether there are any other authorities under the Act that, if implemented, would address any hazards to public health posed by the remaining Utility HAP emissions. The second aspect involves the effectiveness inquiry, which we have now clarified involves an assessment of whether the alternative statutory authority identified can be implemented in a cost-effective and administratively-effective manner.[4]

b. *CMAQ.* EPA received numerous comments regarding its use of the Community Multi-scale Air Quality (CMAQ) modeling system for the Section 112(n) Revision Rule. The Final Reconsideration RTC contains a detailed summary of comments and responses on particular issues raised (*e.g.,* 36 kilometer (km) grid cell, emissions inventory, dry deposition). Below we respond generally to criticisms that it is premature to use CMAQ for this rule, and arguments that recent information from an ongoing receptor modeling study shows that CMAQ underestimates local deposition.

The CMAQ model contains the best science available to EPA to model Hg deposition. All atmospheric modeling analyses include some assumptions and uncertainties that are improved as scientific understanding evolves.

The peer review process was part of this process. The CMAQ peer review process has been the same for Hg, ozone, and fine particulate matter ($PM_{2.5}$).[5] In fact, the latest peer review of CMAQ focused both on $PM_{2.5}$ and Hg. The peer review panel consisted of six to eight experts from academia, industry, and consulting. The panel was charged with review and oversight of all aspects of CMAQ, including emissions pre-processors, meteorological inputs and chemical mechanisms in the model. The peer review panel received documentation and presentations from EPA Office of Research and Development (ORD) scientists on ozone, $PM_{2.5}$, Hg, and other aspects of CMAQ science. The peer review panel was also able to question, in-person, EPA ORD scientists on all aspects of the science contained in CMAQ. After the latest peer review,[6] the panel then prepared a report on the results of their peer review, which is contained on the Community Modeling and Analysis System (CMAS) Web site (*http://www.cmascenter.org*) and in the CAMR docket.[7] In addition the ORD response to this peer review is also found at this location on this Web site. The New York Department of Environmental Conservation findings to-date show CMAQ to be the best performing model for wet deposition at the MDN sites. Importantly, the peer review process did not identify any concerns regarding assumptions used or with uncertainties in the modeling that EPA was not already aware of and considering as it used the model. Thus, although it is true that a portion of the peer review occurred after EPA issued the Section 112(n) Revision Rule and CAMR, even if the peer review had occurred before the rules were final, it would not have resulted in EPA's using CMAQ differently or reaching a different conclusion.

We also received numerous comments citing to an EPA ORD receptor modeling study in Steubenville, Ohio. The Steubenville study can not be directly compared with the model results because, among other things, the Steubenville study included sources other than U.S. power plants and used a different timeframe for its analysis. However, the results of the Steubenville,

[4] We recognize that the final rule may have engendered some confusion as to the two distinct steps of the "necessary" inquiry. For example, in the first column of page 16005 of the final rule, we note that regulation under CAA sections 110(a)(2)(D) and 111 "would effectively address" utility Hg emissions because the level of utility Hg emissions remaining after CAIR will not result in hazards to public health. This discussion in the preamble mixes the first and second steps of the "necessary inquiry." As explained above, the first inquiry under the "necessary" prong is whether there are any alternative authorities in the Act that, *if implemented,* would address the identified hazards to public health associated with the remaining Utility Unit HAP emissions. The second inquiry under the necessary prong involves the effectiveness inquiry and the scope of that inquiry is clarified above.

[5] Because the necessary Hg measurements do not exist, it has not been possible to subject the Hg portion of the model to the kind of evaluation against empirical measurements that the ozone and fine particulate matter portions have received. However, we applied the CMAQ model for CAMR only in a relative sense (the CMAQ estimate of the percent of deposition, not the absolute amount, due to power plants was used as an input into the Mercury Maps model as described in the Effectiveness TSD—thus, empirical validation of absolute values is not as critical to this use of the model.

[6] A December 2003 peer review focused on the total CMAQ platform and specifically on enhancements to the Hg chemical solver, which is responsible for Hg transformation and deposition in CMAQ. A May 2005 peer review included an extended discussion on the CMAQ Hg model science, the specific version of CMAQ used in CAMR, the 2001 model-Mercury Deposition Network (MDN) intercomparison study and the upcoming North American Intercomparison Study.

[7] Community Modeling and Analysis System (CMAS). Final Report: Second Peer Review of the CMAQ Model. July 2005. *http://www.cmascenter.org. See* also EPA–HQ–OAR–2002–0056–6307.

Ohio, receptor modeling study conducted by EPA ORD are consistent, not inconsistent, with those obtained by the CMAQ modeling. The results of this receptor modeling study show that 67 percent of the Hg depositing in precipitation in 2003 at the Steubenville monitor location is from all forms of coal-combustion, with an uncertainty range of ±14 percent. The CMAQ Hg modeling predicts for 2001 that utility coal combustion contributes 44 percent to Hg deposition at the CMAQ 36-km square grid cell containing the Steubenville, Ohio, monitoring site. One grid cell to the north and three grid cells to the east of this monitoring site, the CMAQ model predicts 57 percent and 71 percent, respectively of Hg deposition from utility coal combustion. Thus, because this receptor modeling study provides utility and other coal combustion percentages roughly in the same range as those provided by the CMAQ model for utilities only, it improves confidence in the CMAQ source-attribution results. Furthermore, the CMAQ model predicted wet deposition at the grid cell containing the ORD Steubenville monitoring site of 14.2 micrograms per square meter (μg/m²) for 2001. The measured Hg wet deposition at the Steubenville monitoring site for 2003 is 13.1 μg/m². At the closest MDN site (PA37) to Steubenville, the 2001 CMAQ predicted and measured Hg wet deposition rates are 9.9 and 9.4 μg/m². Thus, it appears that CMAQ model is predicting Hg wet deposition values in the Steubenville area with sufficient accuracy for these rules.

We note that the Steubenville study estimates current deposition at a single point.[8] Although these data will be useful for validating air quality models, they are not useful for estimating exposure because deposition over a larger geographic area is needed to estimate the contribution to watersheds, MeHg concentrations in fish, and ultimately human exposure. As explained in the Effectiveness TSD, Section 2, the hydrologic unit code (HUC–8) watershed is the appropriate scale for estimating exposure to Hg. The CMAQ model, not a single point estimate, is used for estimating deposition within the watersheds.

In conclusion, CMAQ was applied using the best available Hg science for the Section 112(n) Revision Rule. Nonetheless, we recognize that, as new Hg scientific information becomes available and accepted by the scientific community, we will incorporate it into future versions of the CMAQ model. Indeed, EPA released an updated version of the CMAQ Hg model on the CMAS Web site in March 2006 which partially addresses the concerns of the peer review. Importantly, even if we were to use of the March 2006 version of CMAQ it would not materially alter the results of our March decision. Future versions of CMAQ will address other aspects of the peer review.

c. *Public Health Analysis.* EPA conducted a thorough and sophisticated public health analysis pursuant to CAA section 112(n)(1)(A). The final Section 112(n) Revision Rule, the Effectiveness TSD, the Reconsideration TSD, and the Final Reconsideration RTC set forth EPA's methodology and analysis supporting its conclusion under CAA section 112(n)(1)(A) that the utility-attributable emissions remaining after imposition of the requirements of the Act are not reasonably anticipated to pose hazards to public health. Specifically, EPA examined in detail the impact of remaining utility Hg emissions on consumers of self-caught freshwater fish because this exposure pathway results in the highest utility-attributable Hg exposure. See 70 FR 16021; Reconsideration TSD at 1. Thus, consumers of self-caught freshwater fish that substitute other sources of fish (*e.g.*, aquaculture, commercial freshwater, or marine) for self-caught freshwater fish in their diet will lower (reduce) their exposure to utility-attributable Hg.

This sophisticated analysis involved our modeling utility Hg deposition following implementation of CAIR and CAMR, and then applying Mercury Maps and actual fish tissue sample data to estimate corresponding changes in methylmercury (MeHg) fish tissue concentrations. We then folded into the analysis fish consumption rates from various sources, including the Exposure Factors Handbook (EFH), the Methylmercury Water Quality Criterion, and a study of Native American subsistence fisher consumption rates. All of this information was compiled in order to compare the exposure to utility-attributable MeHg for a freshwater fisher to the Reference Dose (RfD) for Hg—what we labeled the index of daily intake (IDI). This comparison was done not only at several consumption rates, including the mean recreational freshwater fisher and the 99th percentile Native American subsistence fisher, but also for various levels of utility-attributable MeHg fish tissue concentrations. *See* Effectiveness TSD, Table 6.4; Final Reconsideration RTC, Table 2. An IDI of less than one (1) is equal to a utility-attributable exposure lower than the RfD. *See* 70 FR 16021.

As these IDI tables show, CAIR, and, furthermore, CAMR, reduce the general public's exposure to utility-attributable MeHg due to freshwater fish consumption well below the RfD (*e.g.*, IDI less than 1). In particular, for all consumption rates analyzed, the IDI is below 1 when eating freshwater fish from up to and including the 50th percentile for fish tissue utility-attributable MeHg. When eating solely freshwater fish in the 75th to 95th percentiles for fish tissue utility-attributable MeHg, the only two groups with IDIs above 1 are the 95th and 99th Native American subsistence fishers. Finally, only when eating solely freshwater fish from the 99th percentile for fish tissue utility-attributable MeHg do the 99th percentile recreational fisher and mean Native American subsistence fisher show IDIs above 1. *See* Effectiveness TSD, Table 6.4; Final Reconsideration RTC, Table 2. These results show that the overwhelming majority of the general public and high-end consumers of self-caught freshwater fish are not expected to be exposed to an IDI above 1 (*e.g.*, utility-attributable MeHg exposure would be below the RfD).

Importantly, as discussed in the final Section 112(n) Revision Rule, the likelihood that factors will converge such that a person would both eat at a high consumption rate and eat solely freshwater fish with high utility-attributable MeHg concentrations is small. *See* 70 FR 16024. Notably, this is true for Native American subsistence fishers because deposition and fish tissue maps indicate that the overwhelming majority of tribal populations live outside areas most impacted by utility-attributable Hg deposition and elevated utility-attributable fish tissue levels. *Id.* Moreover, as discussed elsewhere, although the RfD is an appropriate benchmark, an IDI above 1 (*e.g.*, above the RfD) does not necessarily mean that a public health hazard exists.[9] *Id.*

In the Reconsideration TSD, we looked beyond the self-caught freshwater fish exposure pathway. We were able to undertake a similar quantitative IDI analysis only for the marine fish consumption pathway. That analysis, which likely overstates the utility-attributable Hg levels in marine

[8] We note that the location of the sole monitor for the Steubenville study is not designed to be representative of the deposition to the entire watershed. In fact, it is placed on top of a hill and not at a location where fish are caught.

[9] The World Health Organization (WHO), Health Canada, and the Agency for Toxic Substances and Disease Registry (ATSDR) all set higher thresholds for Hg than EPA's RfD, which would in turn lead to lower IDIs. For example, the WHO sets the level at 0.23 g/kg/day; Health Canada sets the level at 0.2 g/kg/day; and ATSDR sets a value of 0.3 g/kg/day.

fish, showed that for the general public eating at both mean and high-end consumption rates the IDIs are well below 1 (*e.g.*, 0.00 to 0.05). *See* Reconsideration TSD, Table 3.2. EPA went further and calculated IDI values for consumption of marine species with high MeHg concentration, yet those IDIs also were below 1, even for a person consuming in the 99.9th percentile consuming exclusively fish with high utility-attributable MeHg concentrations. *Id.*, Table 3.3. Finally, Table 3 of the Final Reconsideration RTC shows that even when higher marine fish consumption rates (for marine fish with average utility-attributable MeHg concentrations) are added to the freshwater consumption rates, the IDI values do not change substantially (*e.g.*, increase ranges from 0.03 to 0.09).[10] Notably, such an increase is highly unlikely because an individual first would need to eat a large amount of marine fish in addition to a given amount of freshwater fish. Even if it were to occur, such an increase would not materially affect the IDI values, which again supports our focus on utility-attributable exposure from freshwater fish consumption.

Although scientific uncertainties and a lack of data made similar quantitative IDI analyses for other pathways (*e.g.*, commercial freshwater, estuarine, and aquaculture) not possible, EPA presented detailed qualitative analyses showing that the contribution from these pathways would be small, and in all cases are bounded by the self-caught freshwater pathway. *See* Reconsideration TSD, Sections 4 through 7. For example, EPA explained how it is the location and type of feed caught to make fish feed, as opposed to the location of the aquaculture farms, that is relevant to assessing the utility-attributable concentration of MeHg in aquaculture fish. *See* 60 FR 62207. Furthermore, many of the commonly consumed aquaculture fish species (*e.g.*, catfish) tend to have lower concentrations of MeHg than many of the commonly consumed marine fish, and the total amount of aquaculture fish consumed in the U.S. is substantially less than the total amount of marine fish consumed in the U.S. Thus, having already concluded that an upper-bound estimate of utility-attributable Hg exposure due to marine fish is small and that the utility-attributable Hg exposure due to aquaculture is smaller than for marine fish, we reasonably concluded that the utility-attributable Hg exposure due to aquaculture fish is minimal. *Id.*

For the estuarine pathway, we discussed how EPA finds that the available data indicate that the utility-attributable exposure to Hg from estuarine fish and shellfish will likely be small relative to that from self-caught freshwater fish. *Id.* We estimated that the total exposure from the entire global Hg pool (*i.e.*, all Hg sources, including, but, not limited to power plants,) associated with consumption of estuarine and nearcoastal fish is roughly one third of the exposure from all marine species. This estimate of total Hg exposure from estuarine species is thought to be an upper bound because it is based on total Hg concentrations in shellfish rather than MeHg concentrations, the Hg species that is toxicologically most significant. *See* Reconsideration TSD, Section 4. Moreover, of the Hg exposure associated with the consumption of estuarine and near-coastal fish, we estimate that the utility-attributable fraction is small.[11]

Finally, for the commercial freshwater fish pathway, we explained how freshwater commercial fish are not a significant exposure pathway because total consumption is small when compared to recreational freshwater fish consumption. *See* Reconsideration TSD, Section 6; 70 FR 62205. Further, even though utility-attributable Hg deposition is comparatively higher around the Great Lakes and the regional watershed surrounding the Great Lakes as defined by the U.S. Geological Survey (USGS), in comparison with the rest of the U.S., it is still only a small percentage of Hg deposition from all sources. Additionally, only a portion of the commercial freshwater harvesting area is affected by comparatively higher concentrations of utility-attributable Hg deposition in $\mu g/m^2$ (*e.g.*, Lakes Michigan, Erie, and Huron), and the Great Lakes utility-attributable Hg deposition is not disproportionately higher than the immediately surrounding areas for recreational freshwater harvest. All of these factors lead us to believe that the commercial freshwater fish exposure pathway is still expected to be small relative to the national recreational freshwater exposure pathway. *See* 70 FR 62206.

After reviewing the comments received during the reconsideration, we are not changing our analyses of these consumption pathways and continue to find that self-caught freshwater fish represent the pathway most impacted by utility Hg emissions.

Finally, in addition to the above IDI analyses, EPA evaluated whether, following CAIR and, furthermore, following CAMR, there would be any utility hotspots, defined as water bodies that are a source of consumable fish with MeHg tissue concentrations attributable solely to utilities greater than the MeHg water quality criterion of 0.3 mg/kg. *See* 70 FR 16026. EPA's analysis showed that after implementation of CAIR and, furthermore, after CAMR we do not believe that there will be any utility hotspots. *See* 70 FR 16027. Nonetheless, as indicated elsewhere, EPA intends to monitor the situation and take action as necessary. *Id.*[12]

In summary, this information supports EPA's conclusion that following CAIR, and, moreover, following CAMR, utility Hg emissions are not reasonably anticipated to result in a hazard to public health. Specifically, the overwhelming majority of the general public and high-end fish consumers are not expected to be exposed above the MeHg RfD (an IDI value greater than 1). Although the possibility exists that a very small group of people may be exposed above the RfD (an IDI value greater than 1), significant uncertainties exist with respect to the existence and actual size of such a group. There are also significant uncertainties concerning the extent to which such exposure might exceed the RfD (an IDI value greater than 1) and whether exposure at such levels would cause adverse effects. Notably, as the U.S. Court of Appeals for the District of Columbia Circuit in *Vinyl Chloride* held, "safe" does not mean risk-free. *See* 824 F.2d 1165. *Id.* Rather, EPA must "determine what inferences should be drawn from available scientific data and

[10] In Section 1.1.1.1.1 of the Final Reconsideration RTC, EPA explained in more detail why it is very likely that its CAA section 112(n)(1)(A) conclusion regarding hazards to public health would remain unchanged even had it applied the health-based prong of the CAA section 112(f) ample margin of safety inquiry. In particular, we discussed how we effectively considered the factors relevant in the benzene analysis (*e.g.*, estimates of individual risk, incidence, numbers of exposed persons within various risk ranges, scientific uncertainties, weight of evidence, as well as potential standards' technical feasibility, cost, and economic impact).

[11] As described in section 4 of the Reconsideration TSD, utility deposition after CAIR, and even more so after CAMR, is small in the coastal areas, especially taking into account estuarine and near-coastal fisheries on the West Coast. Finally, populated coastal regions like the Chesapeake Bay and Baltimore Harbor (*see* Mason and Lawrence, 1999) will receive significant land-based (*e.g.*, point source discharges) Hg inputs from wastewater effluents, municipal waste discharges, and historical Hg contamination that is slowly leaching from the watershed.

[12] The EPA Inspector General recently issued a report suggesting that EPA conduct monitoring to ensure that its hotspots analysis is accurate. *See* EPA Office of Inspector General, "Monitoring Needed to Assess Impact of EPA's Clean Air Mercury Rule on Potential Hotspots," Report No. 2006–P–00025 (May 15, 2006).

decide what risks are acceptable in the world in which we live." *Id.*

Given the size of the population, including sensitive subpopulations, that after implementation of CAIR and, furthermore, CAMR, will be below the RfD (an IDI value of less than 1); the uncertainty of the size and the level to which certain groups may be exposed above the RfD (an IDI value greater than 1); the uncertainties that adverse effects will be experienced by such groups even at levels significantly above the MeHg RfD; and the nature of those potential adverse effects (*see* Reconsideration TSD), EPA, in its expert judgment, concludes that utility Hg emissions do not pose hazards to public health, and, therefore, that it is not appropriate to regulate such emissions under CAA section 112.

c. *Alternative Global Pool Analysis.* In the final rule, EPA concluded that the utility-attributable emissions remaining after imposition of the requirements of the Act are not reasonably anticipated to pose hazards to public health. Based on this finding and consistent with its interpretation of the term "appropriate," EPA concluded that it was not appropriate to regulate Utility Units under CAA section 112. EPA's analysis did not end there, however. EPA went further and concluded that even examining the impact of the global Hg pool, as opposed to the impacts associated with utility-attributable emissions only, it is still not appropriate to regulate Utility Units under CAA section 112. *See* 70 FR 16028–29 (setting forth global pool analysis). In this regard, EPA looked at the global Hg pool and the impact of eliminating all domestic Utility Unit Hg emissions, including those that enter the global mix (versus deposit relatively quickly in the U.S. or nearby ocean waters). *See* 70 FR 16028–29; 70 FR 62208–09. EPA's analysis showed that total domestic utility-attributable emissions are "a very small fraction of overall methylmercury levels." *Id.* at 16028. The modeling further showed that even if we were to eliminate (versus merely further reduce) all domestic utility-attributable Hg, "virtually none of the risks to public health stemming from the global pool" would be reduced. *See* 70 FR 16029. In the Reconsideration TSD we went further and undertook a bounding exercise of the monetary benefits, based on intelligence quotient (IQ) decrements, which would occur from elimination of utility Hg emissions. In the context of this global pool argument, EPA assumed a hazard to public health existed resulting from global pool emissions, and then properly proceeded with its analysis under the "appropriate" prong.

Specifically, in light of its finding that eliminating all domestic utility-attributable Hg would reduce virtually none of the health risks stemming from the global pool, EPA proceeded in the appropriate inquiry by considering the factor of cost. As explained in detail in Section 8 of the Reconsideration TSD, the lower bound cost of regulating under CAA section 112 beyond CAIR *e.g.*, $750 million) exceeds the upper bound estimate of the benefits of such regulation (*e.g.*, $210 million).[13] See 70 FR 62209. This alternative global pool cost/benefit analysis further supports EPA's conclusion that it is not appropriate to regulate Utility Units under CAA section 112.

Numerous commenters questioned EPA's benefits analysis, citing an article by Trasande, *et al.* (2005), a study prepared for the Northeast States for Coordinated Air Use Management (NESCAUM) entitled, " 'Economic Valuation of Human Health Benefits of Controlling Mercury Emissions from U.S. Coal-fired Power Plants' " (February 22, 2005; NESCAUM Report), and a study by Cohen, *et al.* (2005). The Reconsideration TSD and Final Reconsideration RTC contain our detailed response to these studies; however, a summary follows.

As stated in the Reconsideration TSD, EPA's approach to modeling exposure and health benefits of reducing emissions from power plants differs in some important ways from the approach in the NESCAUM Report. EPA believes that some of these differences simply reflect the large amount of uncertainty in the underlying science. Other differences reflect situations where the science and economics are fairly clear and EPA has concerns about the approach taken in the NESCAUM Report. For example, the NESCAUM Report attempted to quantify the marine exposure pathway but used assumptions that are not supported by the literature on marine fate and transport of Hg, likely resulting in an overestimate by an unknown amount. The NESCAUM Report used REMSAD modeling which appears to over-predict Hg deposition from U.S. power plants. Although EPA does not endorse the approach in the NESCAUM Report approach, at best it should be interpreted as producing an upper-bound estimate of the IQ benefits of reducing Hg emissions from power plants for two reasons. First, it does not appear that the NESCAUM Report took into account the timeframe for reduced exposure to MeHg. This omission alone leads to an overestimate of estimated benefits in the NESCAUM Report by at least a factor of two. Second, EPA's integrated analysis of the three major epidemiological studies (*i.e.*, Faroes, Seychelles, New Zealand) produced an estimated relationship between exposure and neurological problems that EPA feels is much more scientifically defensible than the estimated relationship used in the NESCAUM Report, based, in part, on a then unpublished and generally unavailable study (Cohen *et al.*, *see* below).

EPA believes that many of the assumptions made in the Trasande article lead to an extreme overstatement of the benefits of Hg reduction (or cost of Hg exposure). Most importantly, the article as originally published contained an error in the estimate of the linear dose-response curve that overstated the estimates of that model by a factor of 10. EPA's estimates fall within the range of the corrected estimates, even accepting the author's other assumptions. However, EPA believes that there are other assumptions embedded in the Trasande, *et al.*, analysis that overstate the possible benefits from Hg reductions. Examples include assumptions regarding the amount of Hg in the supply of edible fish in the U.S., the estimate of the percent of the U.S. edible fish supply that is imported, the assumption that 60 percent of the Hg content in fish affected by domestic deposition is due to U.S. sources, and assumptions related to the derivation of IQ decrements associated with exposure to Hg, including the study's primary estimate of IQ decrements being based on a logarithmic model, instead of a linear model (as recommended by the National Research Council (NRC)). Finally, in the Final Reconsideration RTC we discuss several reasons why the results from Trasande, *et al.*, are an overestimate of the economic benefits of controlling Hg.

In regard to the Cohen, *et al.*, article, EPA also disagrees with some of the assumptions made. In particular, a key element of the Cohen, *et al.*, methodology was to convert the log regression coefficients from the Faroe Islands study into corresponding linear coefficients. Because the slope of the log regression relationship varies at different levels of exposure, the corresponding linear coefficient can vary based on which portion of the dose-response relationship is chosen (*e.g.*, ranging from −0.2 to −1.0 IQ points per 1 μg/g increase of Hg in hair).

[13] As explained below, we revised our original estimate of $168 million based on corrections made to the Ryan study.

Although the approach taken by Cohen, *et al.*, is in general a reasonable use of the available data to derive an estimate of the Hg-IQ dose-response relationship, it is evident from the results summarized above that the result is highly sensitive to the assumptions made in converting the log regression coefficients from the Faroe Islands study into linear regression coefficients. The approach taken by EPA and Dr. Ryan was more rigorous than that of Cohen, *et al.*, in a number of respects, but one of the most important differences is that EPA obtained linear regression coefficients directly from the Faroe Islands research team, thus, eliminating the need to make assumptions to convert the log regression coefficients into linear coefficients. If the Cohen, *et al.*, analysis were revised to incorporate the linear coefficients provided by the Faroe Islands researchers to EPA, it is likely that Cohen, *et al.*, would produce a Hg-IQ coefficient very similar to that estimated by Dr. Ryan and used by EPA.

2. Remaining Issues in Petitions for Reconsideration

We deny the petitioners' requests for reconsideration on the remaining issues raised in the petitions because they have failed to meet the standard for reconsideration under CAA section 307(d)(7)(B). Specifically, the petitioners have failed to show: That it was impracticable to raise their objections during the comment period, or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. We discuss our reasons for denying reconsideration in the Final Reconsideration RTC, which is available on our Web site at *http://www.epa.gov/ttn/atw/utility/utiltoxpg.html.*

B. CAMR

CAMR established standards of performance for Hg for new and existing coal-fired electric utility steam generating units (Utility Units), as defined in CAA section 111. The amendments to CAA section 111 rules create a mechanism by which Hg emissions from new and existing coal-fired Utility Units are capped at specified, nation-wide levels. A first phase cap of 38 tons per year (tpy) becomes effective in 2010, and a second phase cap of 15 tpy becomes effective in 2018. Facilities must demonstrate compliance with the standard by holding one "allowance" for each ounce of Hg emitted in any given year. Allowances are readily transferable among all regulated facilities. Such a "cap-and-trade" approach to limiting Hg emissions is the most cost-effective way to achieve the reductions in Hg emissions from the power sector.

At this time, we are announcing our final action after reconsideration of the seven CAMR issues described above. We are also announcing our final decision on reconsideration of the remaining issues that were raised by the petitioners.

1. Issues for Which Reconsideration Was Granted

After carefully considering the petitions and the information that was submitted during the public comment period, we have concluded that one clarification and two revisions to CAMR are warranted. First, for the reasons stated in the October Reconsideration Notice and in the Final Reconsideration RTC, we are finalizing regulatory language to make it clearer that CAMR does not apply to MWC and certain industrial boilers (40 CFR 60.24(h)(8) (definition of "Electric generating unit or EGU"). Specifically, we are providing that CAMR applies to coal-fired boilers and combustion turbines serving, at any time since November 15, 1990, a generator with a nameplate capacity greater than 25 MWe producing electricity for sale and does not apply to cogeneration units meeting certain requirements concerning their electricity sales and to solid waste incineration units combusting municipal waste and subject to certain regulatory requirements. In the October Reconsideration Notice, EPA noted that the Agency would make conforming changes to the applicability provisions in the model trading rule (subpart HHHH, 40 CFR 60.4104) based on the final action EPA takes on the proposed rule as those provisions are intended to be consistent with the definition in 40 CFR 60.24(h). We are, therefore, finalizing revised applicability provisions in 40 CFR 60.4104, which are consistent with the language in revised 40 CFR 60.24(h)(8). (We also noted in the October Reconsideration Notice that we would address the matter of the applicability of units subject to the Industrial Boiler maximum achievable control technology (MACT) standards to units subject to CAMR. We recently proposed language amending 40 CFR part 63, subpart DDDDD, with regard to this matter. *See* 70 FR 62264, 62272; October 31, 2005.) The two changes we are making in response to comments relate to issues raised as a result of our request for comment on: (1) The 2010 phase I Statewide Hg emission budgets and the unit-level Hg emission allocations on which those budgets are based; and, (2) the statistical analysis used for the NSPS. These revisions are discussed further below. A summary of the comments received and our responses to these comments can be found in our Final Reconsideration RTC.

a. *Statewide Hg Allocations.* Several commenters, in response to the issue of the unit-level Hg emission allocations on which the 2010 phase I Statewide Hg emission budget is based, provided data that indicated that EPA had erred in the allocations for the State of Alaska because it had failed to include a coal-fired unit located in the State. EPA has added the heat input values for Healy Unit #1 reported by the commenters, and made the appropriate adjustment to the State of Alaska budget. However, EPA is not making any corrections for the Healy Clean Coal Project as requested by the commenters. EPA calculated State budgets based on historic heat input for all units, not potential or projected heat input.

The original CAMR State budgets and the revised State budgets based on the addition of the Healy Unit #1 heat input data are provided in the Final Reconsideration RTC. Because of the small total adjustment and the digit at which the budgets are rounded, only six other State budgets are affected.

b. *Statistical Analysis for NSPS.* Petitioners expressed considerable concern over EPA's statistical analysis. Further, certain commenters provided additional data in support of a revision to the NSPS emission limits for coal refuse-fired units. EPA did not change its statistical approach but, as noted in the October Reconsideration Notice, we did correct the arithmetic errors. EPA has reviewed its analysis along with the discussions provided by the petitioners and commenters, and reanalyzed the coal refuse NSPS based on the new data and documented the results (*see* Final Reconsideration RTC; revised NSPS memo available in the docket). Based on this reanalysis of the appropriate NSPS emission limits, EPA is finalizing the following NSPS Hg limits for new units:

Bituminous coal	20×10^{-6} lb/MWh
Subbituminous coal (wet units).	66×10^{-6} lb/MWh
Subbituminous coal (dry units).	97×10^{-6} lb/MWh
Lignite coal	175×10^{-6} lb/MWh
Coal refuse	16×10^{-6} lb/MWh
IGCC	20×10^{-6} lb/MWh

2. Remaining Issues in Petitions for Reconsideration

We deny the petitioners' requests for reconsideration on the remaining issues raised in the petitions, because they have failed to meet the standard for reconsideration under CAA section

307(d)(7)(B). Specifically, the petitioners have failed to show: that it was impracticable to raise their objections during the comment period, or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. We discuss our reasons for denying reconsideration in the Final Reconsideration RTC, which is available on our Web site at *http://www.epa.gov/ttn/atw/utility/utiltoxpg.html.*

IV. Issues Not Corrected in the CAMR Technical Corrections or in the Reconsideration Documents

On August 30, 2005 (70 FR 51266), EPA issued a technical corrections document addressing certain corrections to the May 18, 2005 (70 FR 28606) CAMR. We subsequently found certain other errors in CAMR that need correction. All of these corrections should be non-controversial.

On October 28, 2005 (70 FR 62213), EPA proposed to correct the following errors. First, we were inconsistent in our use of phrase "new, modified, and reconstructed" in the applicability provisions of the NSPS portion of CAMR. We proposed to correct this inconsistency by revising the language to indicate that the NSPS applies to units which are constructed, modified, or reconstructed after January 30, 2004. Second, there is an inconsistency between the definitions of "coal" and "coal-fired electric utility steam generating unit." In defining "coal" we indicate that "coal" includes "petroleum coke" while in defining "coal-fired electric utility steam generating unit" we identify "petroleum coke" as an example of a supplemental fuel (*i.e.*, a fuel that is burned with coal). We proposed to correct this inconsistency by removing "petroleum coke" from the definition of "coal" as we do not think "petroleum coke" is properly classified as "coal." (We have subsequently placed "petroleum coke" in the definition of "petroleum"; *see* 70 FR 9877, February 27, 2006.) Third, because of the delay between signature and publication of CAMR, the submittal dates for the individual State Hg allocation plans and the full State plans are not consistent. We proposed to resolve this problem by changing the October 31, 2006 date for submitting Hg allowance allocations to the Administrator specified in 40 CFR 60.24(h)(6)(ii)(C) and 40 CFR 60.4141(a) of the model trading rule to November 17, 2006, consistent with the date for submitting State plans specified in 40 CFR 60.24(h)(2). Finally, we identified additional instances where the section renumbering, noted in the August 30, 2005 document, was not corrected, and we proposed to correct these. We received no comments on these issues as a result of the October 28, 2006 document and, therefore, are finalizing these corrections in this action.

Subsequent to the October 28, 2005 document, we found certain other errors in CAMR. With regard to the inconsistency in our use of the phrase "new, modified, and reconstructed" in the applicability provisions of the NSPS portion of CAMR, we missed instances in CAA sections 60.40Da and 60.45Da where this inconsistency was found. We believe that these corrections are non-controversial and we are correcting these in this action.

V. Statutory and Executive Order (EO) Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

Pursuant to the terms of EO 12866, it has been determined that this final action on reconsideration is a "significant regulatory action" because it raises novel legal or policy issues. As such, the action was submitted to OMB for review under EO 12866. Changes made in response to OMB suggestions or recommendations are documented in the public record.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. This final action on reconsideration imposes no new information collection requirements on the industry. However, the Office of Management and Budget (OMB) has previously approved the information collection requirements contained in the existing regulations (40 CFR 60.40Da–60.49Da; 40 CFR 60.4100–60.4199) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567 and EPA ICR number 2137.02. A copy of the OMB approved Information Collection Request (ICR) may be obtained from Susan Auby, Collection Strategies Division; U.S. Environmental Protection Agency (2822T); 1200 Pennsylvania Ave., NW., Washington DC 20460 or by calling (202) 566–1672.

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

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final action.

For purposes of assessing the impacts of this final action on reconsideration on small entities, a small entity is defined as: (1) A small business that is identified by the NAICS Code, as defined by the Small Business Administration (SBA); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less that 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Categories and entities potentially regulated by the final rule with applicable NAICS codes

are provided in the Supplementary Information section of this action.

According to the SBA size standards for NAICS code 221122 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million MWh.

After considering the economic impacts of this final action on reconsideration on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. EPA has determined that none of the small entities will experience a significant impact because the final action on reconsideration imposes no additional regulatory requirements on owners or operators of affected sources.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, UMRA section 205 generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least-burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least-costly, most cost-effective, or least-burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed, under section 203 of the UMRA, a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA's regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final action on reconsideration does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Although the final rule projected that in 2020, 2 years into the start of the second phase of the cap-and-trade program, compliance costs to government-owned entities would be approximately $48 million, this final action on reconsideration does not add new requirements that would increase this cost. Thus, this final action on reconsideration is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that this final action on reconsideration does not significantly or uniquely affect small governments because it contains no requirements that apply to such governments or impose obligations upon them. Therefore, this final action on reconsideration is not subject to UMRA section 203.

E. Executive Order 13132: Federalism

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

This final action on reconsideration does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. None of the affected facilities are owned or operated by State governments, and the requirements discussed in this action will not supersede State regulations that are more stringent. Thus, EO 13132 does not apply to this final action on reconsideration.

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

EO 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

This final action on reconsideration does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in EO 13175. No affected facilities are owned or operated by Indian tribal governments. Thus, EO 13175 does not apply to this final action on reconsideration.

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

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

This action is a final action on reconsideration of the final CAMR, which is subject to the EO because it is economically significant as defined by EO 12866, and we believe that the environmental health or safety risk addressed by that action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of that final rule on children. The results of the evaluation are discussed in that final rule (70 FR 28606; May 18, 2005) and are contained in the docket (OAR–2002–0056).

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This final action on reconsideration is not a "significant energy action" as defined in EO 13211 (66 FR 28355; May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we conclude that this final

action on reconsideration is not likely to have any adverse energy effects.

I. National Technology Transfer and Advancement Act

As noted in the final rule, section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (*e.g.*, material specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA requires EPA to provide Congress, through the OMB, with explanations when EPA decides not to use available and applicable voluntary consensus standards.

During the development of the final rule, EPA searched for voluntary consensus standards that might be applicable. The search identified three voluntary consensus standards that were considered practical alternatives to the specified EPA test methods. An assessment of these and other voluntary consensus standards is presented in the preamble to the final rule (70 FR 28647; May 18, 2005). This final action on reconsideration does not propose the use of any additional technical standards beyond those cited in the final rule. Therefore, EPA is not considering the use of any additional voluntary consensus standards for this action.

J. Congressional Review Act

The Congressional Review Act (CRA), 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing the final action on reconsideration and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final action on reconsideration in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. The final action on reconsideration is not a "major rule" as defined by 5 U.S.C. 804(2). The final action on reconsideration will be effective June 9, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Coal, Electric power plants, Intergovernmental relations, Metals, Natural gas, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: May 31, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is amended as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, *et seq.*

Subpart B—[Amended]

■ 2. Section 60.24 is amended by:

■ a. In paragraph (h)(3) revising the table;

■ b. In paragraph (h)(6)(ii)(C), by revising the words "October 31, 2006" to read "November 17, 2006"; and

■ c. In paragraph (h)(8), revising the definition of "Electric generating unit or EGU" to read as follows:

§ 60.24 Emission standards and compliance schedules.

* * * * *

(h) * * *

(3) * * *

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
Alaska	0.010	0.004
Alabama	1.289	0.509
Arkansas	0.516	0.204
Arizona	0.454	0.179
California	0.041	0.016
Colorado	0.706	0.279
Connecticut	0.053	0.021
Delaware	0.072	0.028
Florida	1.232	0.487
Georgia	1.227	0.484
Hawaii	0.024	0.009
Iowa	0.727	0.287
Illinois	1.594	0.629
Indiana	2.097	0.828
Kansas	0.723	0.285
Kentucky	1.525	0.602
Louisiana	0.601	0.237
Massachusetts	0.172	0.068
Maryland	0.490	0.193
Maine	0.001	0.001
Michigan	1.303	0.514
Minnesota	0.695	0.274
Missouri	1.393	0.550
Mississippi	0.291	0.115
Montana	0.377	0.149
Navajo Nation	0.600	0.237
North Carolina	1.133	0.447
North Dakota	1.564	0.617
Nebraska	0.421	0.166

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
New Hampshire	0.063	0.025
New Jersey	0.153	0.060
New Mexico	0.299	0.118
Nevada	0.285	0.112
New York	0.393	0.155
Ohio	2.056	0.812
Oklahoma	0.721	0.285
Oregon	0.076	0.030
Pennsylvania	1.779	0.702
South Carolina	0.580	0.229
South Dakota	0.072	0.029
Tennessee	0.944	0.373
Texas	4.656	1.838
Utah	0.506	0.200
Ute Indian Tribe	0.060	0.024
Virginia	0.592	0.234
Washington	0.198	0.078
Wisconsin	0.890	0.351
West Virginia	1.394	0.550
Wyoming	0.952	0.376
Total	38.000	15.000

* * * * *

(8) * * *

Electric generating unit or *EGU* means:

(1)(i) Except as provided in paragraphs (2) and (3) of this definition, a stationary, coal-fired boiler or stationary, coal-fired combustion turbine in the State serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 megawatts electric (MWe) producing electricity for sale.

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

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

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

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

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

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

(3) A "solid waste incineration unit" as defined in Clean Air Act section 129(g)(1) combusting "municipal waste" as defined in Clean Air Act section 129(g)(5) shall not be an electric generating unit if it is subject to one of the following rules:

(i) An EPA-approved State plan for implementing subpart Cb of part 60 of this chapter, "Emissions Guidelines and Compliance Times for Large Municipal Waste Combustors That Are Constructed On or Before September 20, 1994";

(ii) Subpart Eb of part 60 of this chapter, "Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996";

(iii) Subpart AAAA of part 60 of this chapter, "Standards of Performance for Small Municipal Waste Combustors for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001";

(iv) An EPA-approved State Plan for implementing subpart BBBB of part 60 of this chapter, "Emission Guidelines and Compliance Times for Small Municipal Waste Combustion Units Constructed On or Before August 30, 1999";

(v) Subpart FFF of part 62 of this chapter, "Federal Plan Requirements for Large Municipal Waste Combustors Constructed On or Before September 20, 1994; or

(vi) Subpart JJJ of 40 CFR part 62, "Federal Plan Requirements for Small Municipal Waste Combustion Units Constructed On or Before August 30, 1999".

* * * * *

Subpart Da—[Amended]

■ 3. Section 60.40Da is amended by revising paragraph (a)(2) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

(a) * * *

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

* * * * *

■ 4. Section 60.41Da is amended by revising the definitions of "Coal" and "Coal-fired electric utility steam generating unit" and in paragraph (b) of the definition of "Potential combustion concentration" by revising "§ 60.48a(b)" to read "§ 60.50Da(b)" to read as follows:

§ 60.41Da Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004) $^{\varepsilon 1}$ (incorporated by reference, see § 60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

* * * * *

■ 5. Section 60.45Da is amended by:
■ a. Revising paragraph (a) introductory text;
■ b. Revising paragraph (a)(1);
■ c. Revising paragraphs (a)(2)(i) and (a)(2)(ii);
■ d. Revising paragraph (a)(3);
■ e. Revising paragraph (a)(4); and
■ f. Revising paragraph (b) to read as follows:

§ 60.45Da Standard for mercury.

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in § 60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 20×10^{-6} pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 nanograms per joule (ng/J).

(2)* * *

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 97×10^{-6} lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 175×10^{-6} lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 16×10^{-6} lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

* * * * *

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of 20×10^{-6} lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in § 60.50Da(g).

■ 6. Section 60.48Da is amended:
■ a. In paragraph (j) introductory text by revising "§ 60.44a(a)" to read "§ 60.44Da(a)";
■ b. Revising paragraph (l) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(l) Compliance provisions for sources subject to § 60.45Da. The owner or operator of an affected facility subject to § 60.45Da (new sources constructed, modified, or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of § 60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of § 60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in § 60.49Da(k). Compliance with the applicable standard under § 60.45Da is determined on a 12-month rolling average basis.

* * * * *

§ 60.50Da [Amended]

■ 7–8. Section 60.50Da is amended by:
■ a. In paragraph (e)(2) by revising "§ 60.48(d)(1)" to read "§ 60.46(d)(1)"; and
■ b. In paragraph (g) introductory text, by removing the words "and 60.46Da".

Subpart Db—[Amended]

§ 60.40b [Amended]

■ 9. Section 60.40b is amended in paragraph (e) by revising "§ 60.40a" to read "§ 60.40Da".

Subpart HHHH—Amended]

■ 10. Section 60.4104 is revised to read as follows:

§ 60.4104 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be Hg Budget units, and any source that includes one or more such units shall be a Hg Budget source, subject to the requirements of this subpart and subparts BB through HH of this part: Any stationary, coal-fired boiler or stationary, coal-fired combustion turbine serving at any time, since the

later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

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

(b) The units in a State that meet the requirements set forth in paragraphs (b)(1)(i) or (b)(2) of this section shall not be Hg Budget units:

(1)(i) Any unit that is a Hg Budget unit under paragraph (a)(1) or (2) of this section:

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

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

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

(2) Any unit that is an Hg Budget unit under paragraph (a)(1) or (2) of this section, is a solid waste incineration unit combusting municipal waste, and is subject to the requirements of:

(i) A State Plan approved by the Administrator in accordance with subpart Cb of part 60 of this chapter (emissions guidelines and compliance times for certain large municipal waste combustors);

(ii) Subpart Eb of part 60 of this chapter (standards of performance for certain large municipal waste combusters);

(iii) Subpart AAAA of part 60 of this chapter (standards of performance for certain small municipal waste combustors);

(iv) A State Plan approved by the Administrator in accordance with subpart BBBB of part 60 of this chapter (emission guidelines and compliance times for certain small municipal waste combustion units);

(v) Subpart FFF, of part 62 of this chapter (Federal Plan requirements for certain large municipal waste combustors); or

(vi) Subpart JJJ of part 62 of this chapter (Federal Plan requirements for certain small municipal waste combustion units).

■ 11. Section 60.4140 is revised to read as follows:

§ 60.4140 State trading budgets.

The State trading budgets for annual allocations of Hg allowances for the control periods in 2010 through 2017 and in 2018 and thereafter are respectively as follows:

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
Alaska	0.010	0.004
Alabama	1.289	0.509
Arkansas	0.516	0.204
Arizona	0.454	0.179
California	0.041	0.016
Colorado	0.706	0.279
Connecticut	0.053	0.021
Delaware	0.072	0.028
Florida	1.232	0.487
Georgia	1.227	0.484
Hawaii	0.024	0.009
Iowa	0.727	0.287
Illinois	1.594	0.629
Indiana	2.097	0.828
Kansas	0.723	0.285
Kentucky	1.525	0.602
Louisiana	0.601	0.237
Massachusetts	0.172	0.068
Maryland	0.490	0.193
Maine	0.001	0.001
Michigan	1.303	0.514
Minnesota	0.695	0.274
Missouri	1.393	0.550
Mississippi	0.291	0.115
Montana	0.377	0.149
Navajo Nation	0.600	0.237
North Carolina	1.133	0.447
North Dakota	1.564	0.617
Nebraska	0.421	0.166
New Hampshire	0.063	0.025
New Jersey	0.153	0.060
New Mexico	0.299	0.118
Nevada	0.285	0.112

State	Annual EGU Hg budget (tons)	
	2010–2017	2018 and thereafter
New York	0.393	0.155
Ohio	2.056	0.812
Oklahoma	0.721	0.285
Oregon	0.076	0.030
Pennsylvania	1.779	0.702
South Carolina	0.580	0.229
South Dakota	0.072	0.029
Tennessee	0.944	0.373
Texas	4.656	1.838
Utah	0.506	0.200
Ute Indian Tribe	0.060	0.024
Virginia	0.592	0.234
Washington	0.198	0.078
Wisconsin	0.890	0.351
West Virginia	1.394	0.550
Wyoming	0.952	0.376
Total	38.000	15.000

■ 11. Section 60.4141 is amended by revising paragraph (a) to read as follows:

§ 60.4141 Timing requirements for Hg allowance allocations.

(a) By November 17, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with § 60.4142(a) and (b), for the control periods in 2010, 2011, 2012, 2013, and 2014.

* * * * *

[FR Doc. 06–5173 Filed 6–8–06; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192, 193, and 195

[Docket No. PHMSA–05–21253; Amdt. Nos. 192–103, 193–19, and 195–86]

RIN 2137–AD68

Pipeline Safety: Update of Regulatory References to Technical Standards

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: This final rule updates the pipeline safety regulations to incorporate by reference all or parts of new editions of voluntary consensus technical standards to enable pipeline operators to utilize current technology, materials, and practices.

DATES: This final rule takes effect on July 10, 2006. The incorporation by reference of publications listed in the rule is approved by the Director of the Federal Register as of July 10, 2006.

FOR FURTHER INFORMATION CONTACT: Richard D. Huriaux, Director, Technical Standards at (202) 366–4565, by fax at (202) 366–4566, or by e-mail at *richard.huriaux@dot.gov*. Copies of this document or other material in the docket can be reviewed by accessing the Docket Management System's home page at *http://dms.dot.gov*. General information on the pipeline safety program is available at PHMSA's Web site at *http://ops.dot.gov*.

SUPPLEMENTARY INFORMATION:

I. Background

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113) directs Federal agencies to use voluntary consensus standards in lieu of government-written standards whenever possible. Voluntary consensus standards are standards developed or adopted by voluntary bodies that develop, establish, or coordinate technical standards using agreed upon procedures.

PHMSA participates in more than 25 national voluntary consensus standards committees. PHMSA's policy is to adopt voluntary consensus standards when they are applicable to pipeline design, construction, maintenance, inspection, and repair. In recent years, PHMSA has adopted dozens of new and revised voluntary consensus standards into its gas pipeline (49 CFR part 192), hazardous liquid pipeline (49 CFR part 195), and liquefied natural gas (LNG) (49 CFR part 193) regulations.

Parts 192, 193, and 195 incorporate by reference all or parts of more than 60 standards and specifications developed and published by technical organizations, including the American Petroleum Institute, American Gas Association, American Society of Mechanical Engineers, American Society for Testing and Materials, Manufacturers Standardization Society of the Valve and Fittings Industry, National Fire Protection Association, Plastics Pipe Institute, and Pipeline Research Council International. These organizations update and revise their published standards every 3 to 5 years, to reflect modern technology and best technical practices. PHMSA has reviewed the revised voluntary consensus standards to be incorporated in whole or in part in 49 CFR parts 192, 193, and 195.

This final rule updates the Federal pipeline safety regulations to incorporate by reference all or parts of recent editions of the voluntary consensus technical standards that are currently referenced in the Federal pipeline safety regulations. It updates 38 standards in 49 CFR part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards*, 49 CFR part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards*, and 49 CFR part 195, *Transportation of Hazardous Liquids by Pipeline*. This update enables pipeline operators to use current technology, materials, and practices. The incorporation of the most recent editions of standards improves clarity, consistency, and accuracy, and reduces unnecessary burdens on the regulated community.

Previous updates of the regulations to incorporate revised standards were issued on May 24, 1996 (61 FR 26121), June 6, 1996 (61 FR 2877), February 17, 1998 (63 FR 7721), and June 14, 2004

Unfunded Mandates Reform Act

Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

Executive Order 13175 Consultation and Coordination With Indian Tribal Governments

This rule also does not have tribal implications because it will not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified by Executive Order 13175 (59 FR 22951, November 9, 2000).

Executive Order 13132 Federalism

This action also does not have Federalism implications because it does not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act.

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

This rule also is not subject to Executive Order 13045 "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), because it is not economically significant.

National Technology Transfer Advancement Act

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. In this context, in the absence of a prior existing requirement for the state to use voluntary consensus standards (VCS), EPA has no authority to disapprove a SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the Clean Air Act. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply.

Paperwork Reduction Act

This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. section 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 31, 2006. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Intergovernmental relations.

Dated: May 19, 2006.

Norman Niedergang,

Acting Regional Administrator, Region 5.

■ For the reasons stated in the preamble, part 52, chapter I, of title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart KK—Ohio

■ 2. Section 52.1887 is amended by adding paragraph (e) to read as follows:

§ 52.1887 Control strategy: Carbon monoxide.

* * * * *

(e) Approval—On October 20, 2005, Ohio submitted a State Implementation Plan (SIP) revision of the Cuyahoga County carbon monoxide (CO) maintenance plan. The CO maintenance plan revision is an update to the current approved maintenance plan and continues to demonstrate maintenance of the CO National Ambient Air Quality Standard (NAAQS) for an additional 10 years. The maintenance plan revision is submitted as a limited maintenance plan for the Cuyahoga County, Ohio carbon monoxide area and provides an unlimited motor vehicle emissions budget as long as the ambient CO levels remain below the 7.65 parts per million design value specified as the criterion for the limited maintenance plan.

[FR Doc. 06–5013 Filed 5–31–06; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[A–91–07; FRL–8176–8]

RIN 2060–AG22

Amendments to Standards of Performance for New Stationary Sources; Monitoring Requirements

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction.

SUMMARY: The EPA issued a final rule on August 10, 2000, that revised the monitoring requirements in Performance Specification 1 (PS–1). The revisions updated requirements for source owners and operators who must install and use continuous stack or duct opacity monitoring equipment. The revisions also updated design and performance validation requirements for continuous opacity monitoring system (COMS) equipment in PS–1. In addition to changes to PS–1, the final rule established differences between gaseous continuous emissions monitoring systems (CEMS) and COMS. The final rule contained a minor error in wording. This action is intended to correct this error. All other preamble and regulatory text printed in the August 10, 2000, final rule is correct.

DATES: This correction is effective June 1, 2006.

FOR FURTHER INFORMATION CONTACT: Rima Howell, Measurement Technology Group, Air Quality Assessment Division (E–143–02), Office of Air Quality Planning and Standards, EPA, Research Triangle Park, NC 27711; telephone number (919) 541–0443; fax number (919) 541–0516; electronic mail (e-mail) address *howell.rima@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

The EPA promulgated revisions to the Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources, PS–1 (40 CFR part 60, Appendix B) and revised § 60.13(d)(1) in the **Federal Register** (65 FR 48914) on August 10, 2000. Following the promulgation of these sections, Phelps Dodge Miami, Inc., requested that we issue a correction to § 60.13(d)(1). Their request pointed out that the Agency had inadvertently modified a requirement for CEMS, thus adding a requirement to obtain calibration data automatically. The Agency agrees that the automatic data gathering requirement was only intended to address COMS systems, not CEMS, and has agreed to address this issue.

II. Summary of Amendment

The EPA issued a final rule on August 10, 2000, (65 FR 48914) that revised the monitoring requirements in Performance Specification 1 (PS–1) of Appendix B of part 60. The revisions updated requirements for source owners and operators who must install and use continuous stack or duct opacity monitoring equipment. The revisions also updated design and performance validation requirements for COMS equipment in PS–1. In addition to changes to PS–1, the final rule revised § 60.13(d)(1) to distinguish between CEMS and COMS. The final rule contained a minor error in the revised § 60.13(d)(1). This action is intended to correct this error.

The incorrect wording is found in the first sentence of § 60.13(d)(1), which erroneously requires that owners and operators of CEMS must "automatically" check the zero and span calibration drifts at least once daily in accordance with a written procedure. The word "automatically" was not intended to be a requirement for CEMS, while it is a requirement for COMS. The word "automatically" was used in reference to CEMS by mistake, and is being removed.

III. Statutory and Executive Order Reviews

Under Executive Order 12866, Regulatory Planning and Review (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is, therefore, not subject to review by the Office of Management and Budget ("OMB"). This action is not a "major rule" as defined by 5 U.S.C. 804(2). The correction does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 [44 U.S.C. 3501 *et seq.*].

Because EPA has made a "good cause" finding that this action is not subject to notice and comment requirements under the APA or any other statute, it is not subject to the regulatory flexibility provisions of the Regulatory Flexibility Act [5 U.S.C. 601 *et seq.*], or to sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 [Pub. L. 104–4]. In addition, this action does not significantly or uniquely affect small governments or impose a significant intergovernmental mandate, as described in sections 203 and 204 of the UMRA.

The correction does not have substantial direct effects on the States, or on the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of Government, as specified in Executive Order 13132, Federalism (64 FR 43255, August 10, 1999).

Today's action also does not significantly or uniquely affect the communities of tribal governments, as specified by Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (65 FR 67249, November 9, 2000). The technical correction also is not subject to Executive Order 13045, Protection of Children from Environmental Health and Safety Risks (62 FR 19885, April 23, 1997) because it is not economically significant.

The correction is not subject to Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

Section 553 of the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(B), provides that, when an Agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the Agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making today's action final without prior proposal and opportunity for comment because the change to the rule corrects an error, is noncontroversial, and is consistent with the technical basis of the rule. Thus, notice and public procedure are unnecessary. We find that this constitutes good cause under 5 U.S.C. 553(b)(B) (see also the final sentence of section 307(d)(1) of the Clean Air Act (CAA), 42 U.S.C. 7607(d)(1), indicating that the good cause provisions of the APA continue to apply to rulemaking under section 307(d) of the CAA).

Section 553(d)(3) allows an agency, upon a finding of good cause, to make a rule effective immediately. Because today's changes relieve an unintended requirement, we find good cause to make these technical corrections effective immediately.

The correction action does not involve changes to the technical standards related to test methods or monitoring methods; thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply.

The correction also does not involve special consideration of environmental justice-related issues as required by Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 FR 7629, February 16, 1994).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by SBREFA of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of today's action in the **Federal Register**. Today's action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on June 1, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Air pollution control, Carbon monoxide, Reporting and recordkeeping requirements.

Dated: May 23, 2006.

William L. Wehrum,

Acting Assistant Administrator, Office of Air and Radiation.

■ For the reasons stated in the preamble, title 40, Chapter I of the Code of Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 60.13 by revising the first sentence of paragraph (d)(1) as follows:

§ 60.13 Monitoring requirements.

* * * * *

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. * * *

* * * * *

[FR Doc. E6–8397 Filed 5–31–06; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2006–0088; FRL–8060–5]

Zoxamide; Pesticide Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct Final rule.

SUMMARY: EPA issued a final rule in the **Federal Register** of September 26, 2001, concerning a tolerance for combined re

Federal Register

Monday,
February 27, 2006

Part II

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Electric Utility Steam Generating Units, Industrial–Commercial–Institutional Steam Generating Units, and Small Industrial–Commercial–Institutional Steam Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2005–0031; FRL–8033–3]

RIN 2060–AM80

Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; amendments.

SUMMARY: Pursuant to section 111(b)(1)(B) of the Clean Air Act (CAA), EPA has reviewed the emission standards for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) contained in the new source performance standards (NSPS) for electric utility steam generating units and industrial-commercial-institutional steam generating units. EPA proposed amendments to 40 CFR part 60, subparts Da, Db, and Dc, on February 28, 2005. This action reflects EPA's responses to issues raised by commenters, and promulgates the amended standards of performance.

The final rule amendments revise the existing standards for PM emissions by reducing the numerical emission limits for both utility and industrial-commercial-institutional steam generating units and revise the existing standards for NO_X emissions by reducing the numerical emission limits for utility steam generating units. The amendments also revise the standards for SO_2 emissions for both electric utility and industrial-commercial-institutional steam generating units. The numerical standard for electric utility steam generating units has been reduced, and the maximum percent reduction requirement has been increased. A numerical standard has been added for units presently subject to the NSPS and new industrial-commercial-institutional steam generating units, and the maximum percent reduction requirement for new units has been increased. Both utility and industrial steam generating units can either meet a numerical limit or demonstrate a percent reduction.

Several technical clarifications and compliance alternatives have been added to the existing provisions of the current rules.

DATES: The final rule amendments are effective on February 27, 2006.

ADDRESSES: *Docket:* EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0031. All documents in the docket are listed on the Internet at *http://www.regulations.gov.* Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket, Docket ID No. EPA–HQ–2004–0490, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–4003; e-mail *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Categories and entities potentially regulated by the final rule amendments are new, reconstructed, and modified electric utility steam generating units and new, reconstructed, and modified industrial-commercial-institutional steam generating units. The final rule amendments will affect the following categories of sources:

Category	NAICS code	SIC code	Examples of potentially regulated entities
Industry	221112		Fossil fuel-fired electric utility steam generating units.
Federal Government	22112		Fossil fuel-fired electric utility steam generating units owned by the Federal Government.
State/local/tribal government	22112		Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150		Fossil fuel-fired electric steam generating units in Indian Country.
Any industrial, commercial, or institutional facility using a boiler as defined in 60.40b or 60.40c.	211	13	Extractors of crude petroleum and natural gas.
	321	24	Manufacturers of lumber and wood products.
	322	26	Pulp and paper mills.
	325	28	Chemical manufacturers.
	324	29	Petroleum refiners and manufacturers of coal products.
	316, 326, 339	30	Manufacturers of rubber and miscellaneous plastic products.
	331	33	Steel works, blast furnaces.
	332	34	Electroplating, plating, polishing, anodizing, and coloring.
	336	37	Manufacturers of motor vehicle parts and accessories.
	221	49	Electric, gas, and sanitary services.
	622	80	Health services.
	611	82	Educational services.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be subject to the final rule amendments. To determine whether your facility may be subject to the final rule amendments, you should examine the applicability criteria in 40 CFR part 60, sections 60.40a, 60.40b, or 60.40c. If you have any questions regarding the applicability of the final rule amendments to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of today's action is available on the WWW through the Technology Transfer Network (TTN). Following signature, EPA has posted a copy of today's action on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn.* The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by April 28, 2006. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by today's final action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for EPA to convene a proceeding for reconsideration, "if the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave, NW., Washington, DC 20004.

Outline. The following outline is provided to aid in locating information in this preamble.

I. Summary of Final Rule

The final rule amends the emission limits for SO_2, NO_X, and PM for subpart Da, 40 CFR part 60 (electric utility steam generating units) the SO_2 and PM emission limits for subpart Db, 40 CFR part 60 (industrial-commercial-institutional steam generating units), and the SO_2 and PM emission limits for subpart Dc, 40 CFR part 60 (small industrial-commercial-institutional steam generating units). With one exception, only those units that begin construction, modification, or reconstruction after February 28, 2005, will be affected by the final rule. The exception is that the SO_2 standard for industrial-commercial-institutional units presently subject to the NSPS has been amended to reflect the difficulty of units burning fuels with inherently low sulfur emissions from consistently achieving 90 percent reduction. Compliance with the emission limits of the final rule will be determined using similar testing, monitoring, and other compliance provisions set forth in the existing standards.

In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the existing amendments, as explained below. We included language to clarify the applicability of subparts Da, Db, and Dc of 40 CFR part 60 to combined cycle power plants. Heat recovery steam generators that are associated with combined cycle and combined heat and power combustion turbines burning less than 75 percent (by heat input) synthetic-coal gas are not subject to subparts Da, Db, or Dc, 40 CFR part 60, if the unit meets the applicability requirements of subpart KKKK, 40 CFR part 60 (Standards of Performance for Stationary Combustion Turbines). Subpart Da of 40 CFR part 60 will apply to combined cycle and combined heat and power combustion turbines and the associated heat recovery units that burn 75 percent or more (by heat input) synthetic-coal gas (e.g., integrated coal gasification combine cycle power plants) and that meet the applicability criteria of the final rule amendments, respectively.

We also made amendments to the definitions for boiler operating day, cogeneration, coal, gross output, and petroleum. The purpose of the final rule amendments is to clarify definitions across the three subparts and to incorporate the most current applicable American Society for Testing and Materials (ASTM) testing method references. Also, we clarified the definition of an "electric utility steam generating unit" as applied to cogeneration units.

A. What are the requirements for new electric utility steam generating units (40 CFR part 60, subpart Da)?

The PM emission limit for new and reconstructed electric utility steam generating units is 6.4 nanograms per joule (ng/J) (0.015 pound per million British thermal units (lb/MMBtu)) heat input or 99.9 percent reduction regardless of the type of fuel burned. The PM emission limit for modified electric utility steam generating units is 6.4 ng/J (0.015 lb/MMBtu) heat input or 99.8 percent reduction regardless of the type of fuel burned. Compliance with this emission limit can be determined using similar testing, monitoring, and other compliance provisions for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance

and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new electric utility steam generating units is 180 ng/J (1.4 pound per megawatt hour (lb/MWh)) gross energy output or 95 percent reduction regardless of the type of fuel burned with one exception. The SO_2 emission limit for new electric utility steam generating units that burn over 75 percent coal refuse (by heat input) is 180 ng/J (1.4 lb/MWh) gross energy output or 94 percent reduction. The SO_2 emission limit for reconstructed and modified electric utility steam generating units burning any fuel except over 75 percent coal refuse (by heat input) is 65 ng/J (0.15 lb/MMBtu) heat input or 95 percent reduction and 65 ng/J (0.15 lb/MMBtu) heat input or 90 percent reduction, respectively. The SO_2 emission limit for reconstructed and modified electric utility steam generating units burning over 75 percent coal refuse (by heat input) is 65 ng/J (0.15 lb/MMBtu) or 94 percent reduction and 65 ng/J (0.15 lb/MMBtu) or 90 percent reduction, respectively. Compliance with the SO_2 emission limit is determined on a 30-day rolling average basis using a CEMS to measure SO_2 emissions as discharged to the atmosphere and following the compliance provisions in the existing rule for the output-based NO_X standards applicable to new sources that were built after July 9, 1997.

The NO_X emission limit for new electric utility steam generating units is 130 ng/J (1.0 lb NO_X/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-day rolling average basis using similar testing, monitoring, and other compliance provisions in the existing rule for the output-based NO_X standards applicable to new sources that were built after July 9, 1997. The NO_X limit for reconstructed and modified electric utility steam generating units is 47 ng/J (0.11 lb/MMBtu) heat input and 65 ng/J (0.15 lb/MMBtu) heat input, respectively.

B. What are the requirements for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db)?

The PM emission limit for new and reconstructed industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels. The PM emission limit for modified industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input or 99.8 percent reduction [with a maximum emission limit of 22 ng/J (0.051 lb/MMBtu) heat input] for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels with two exceptions. The standard for modified wood-fired units with a maximum heat input less than or equal to 250 MMBtu/h is 43 ng/J (0.10 lb/MMBtu) heat input and 37 ng/J (0.085 lb/MMBtu) heat input for larger modified wood-fired boilers. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity monitoring requirements.

Units burning only oil, that contains no more than 0.3 weight percent sulfur, or liquid or gaseous fuels with a potential sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input, may demonstrate compliance with the PM standard by maintaining certification of the fuels burned. Such units are not required to conduct PM compliance tests, conduct continuous monitoring, or comply with any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

The SO_2 emission limit for new and reconstructed industrial-commercial-institutional steam generating units is 87 ng/J (0.20 lb/MMBtu) heat input, or 92 percent reduction with a maximum emission rate of 520 ng/J (1.2 lb/MMBtu). Compliance with the SO_2 emission limits is determined following similar procedures as in the existing NSPS.

Units burning only oil that contains no more than 0.3 weight percent sulfur or any individual fuel that, when combusted without SO_2 emission control, have an SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input are exempt from other SO_2 emission limits and may demonstrate compliance with the SO_2 standard by maintaining certification of the fuels burned. Such units are not required to conduct SO_2 compliance tests, conduct continuous monitoring, or comply with any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

An alternate numerical SO_2 limit of 87 ng/J (0.20 lb/MMBtu) heat input has been added both for units presently subject to the NSPS and for modified units. The alternative limit has been made available to units presently subject to the NSPS as well as modified units in recognition of the technical difficulties of facilities firing inherently low sulfur fuels to achieve 90 percent reduction.

C. What are the requirements for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc)?

The PM emission limit for new and reconstructed small industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels. The PM emission limit for modified industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/MMBtu) heat input or 99.8 percent reduction for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels with one exception. The standard for modified wood-fired industrial-commercial-institutional steam generating units is 43 ng/J (0.10 lb/MMBtu) heat input. These limits apply to units between 8.7 MW and 29 MW (30 to 100 MMBtu/h) heat input. While not required, PM CEMS may be used as an alternate method to demonstrate continuous compliance and as an alternative to opacity monitoring.

Units burning only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels that, when combusted without SO_2 emission control, have a SO_2 emission rate equal to or less than 230 ng/J (0.54 lb/MMBtu) heat input, may demonstrate compliance with the PM standard by maintaining certification of the fuels burned. Such units are not required to conduct PM compliance tests, conduct continuous monitoring, or any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

II. Background Information

A. What is the statutory authority for the final rule?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for electric utility steam generating units (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for electric utility steam generating units (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent amendments to emission standards under subpart Da, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_X limitations for subpart Da, 40 CFR part 60, units. Furthermore, in the 1998 amendments, the use of output-based emission limits was incorporated.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BDT for these sources. The most recent amendments to emission standards under subpart Db, 40 CFR part 60, were promulgated in 1998 (63 FR 49442) resulting in new NO_X limitations for subpart Db, 40 CFR part 60, units.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990, (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

III. Responses to Public Comments

The proposed rule was published February 28, 2005 (70 FR 9706).

A. Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da)

Greenhouse Gases

Comment: One group of commenters state that CAA section 111 requires EPA to set standards of performance for each pollutant emitted by a source category that causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The commenters presented an argument to support their conclusion that carbon dioxide (CO_2) and other greenhouse gases emitted by steam generating units are "reasonably anticipated to endanger public health or welfare." Thus, EPA must set NSPS for greenhouse gases emitted from steam generating units.

One commenter states that the electricity sector includes the nation's largest sources of CO_2 emissions, and it is essential that EPA utilize its authority to limit CO_2 emissions under CAA section 111. The commenter states that, in the preamble, EPA alludes to the importance of controlling greenhouse gases, and that EPA revised its earlier position that it did have authority to regulate CO_2; the commenter notes that this position is currently under judicial review. The commenter summarizes the public health dangers from rising CO_2 levels and provides supporting attachments to its submittal. The commenter states that technologies, e.g., integrated gasification combine cycle (IGCC) technology and others, are available to the electric utility industry to reduce CO_2 emissions that were not available in 1979 when the power plant NSPS were promulgated. The commenter attached supporting information on the available technology for lowering CO_2 emissions. For existing sources, the commenter recommends that EPA require States to implement standards of performance for CO_2 from existing sources. According to the commenter, CAA section 111(d) provides that EPA require States to implement standards of performance for existing sources when the pollutant is not regulated as a criteria pollutant. A program of trading CO_2 emission credits is an effective way of regulating CO_2 emissions from existing sources.

One commenter recommends that EPA set CO_2 emission limits as minimum thermal efficiency levels for boilers.

Response: EPA's statutory authority for establishing NSPS to control air pollutants from stationary sources is under CAA section 111. EPA has concluded that it does not presently have the authority to set NSPS to regulate CO_2 or other greenhouse gases that contribute to global climate change.

Selection of NO_X Emission Level

Comment: One group of commenters state that to meet the requirements of CAA section 111, EPA must establish a NO_X limit of no more than 0.5 lb/MWh for electric utility steam generating units. The commenters present information and data references to support their selection of a NO_X emission level for the NSPS.

One commenter states that a lower NO_X emission standard of 0.7 or 0.8 lb/MWh is justified based on existing demonstrated technology and is consistent with the mandate in section 111 of the CAA. The commenter cites two fluidized bed boilers that began operating in the late 1980s and have been retrofitted with selective non-catalytic reduction (SNCR) and have actual NO_X emission rates between 0.12 and 0.13 lb/MMBtu.

One commenter states that the standards for NO_X are insufficiently stringent and do no reflect the best system of emission reduction as required by CAA section 111. The commenter provides the following supporting rationale for their view: The 1.0 lb/MWh standard is based on an input-based level of 0.11 lb/MMBtu, which is well above the levels being achieved with recent selective catalytic reduction (SCR) installations. The commenter attached 2003 data showing at least 62 coal-fired plant units achieving a rate of 0.100 lb/MMBtu or below and 37 units emitted at a rate at or below 0.080 lb/MMBtu. New plants should be able to do better. EPA acknowledges that SCR can reduce NO_X emissions by at least 90 percent. Because most existing facilities subject to the final rule are meeting rates of 0.30–0.60 lb/MMBtu without SCR, units with SCR should readily achieve these levels. Even though EPA recognizes that SCR is BDT, it is proposing a less stringent standard based on fluidized beds and advanced combustion controls as an alternative to SCR or SNCR. This contravenes section 111. EPA uses efficiency data for existing plants rather than higher efficiency levels achievable by new plants using either SCR or IGCC technology. A standard closer to the lower end of the range being considered is appropriate.

One commenter states that new coal-fired units can achieve NO_X emission limits of less than 0.500 lb/MWh through the implementation of low NO_X burners and SCR technologies.

One commenter reviewed recent BACT determinations in new source permits for electric utility steam-generating units of more than 250 MMBtu/h (combusting bituminous, subbituminous, anthracite and lignite coal) from EPA's Clean Air Technology Center RACT/BACT/LAER Clearinghouse (RBLC) and examined the five most recent permitting decisions. The commenter included RBLC data showing that the permitted NO_X emission limits for all five were 0.07 or 0.08 lb/MMBtu. The commenter states that, as reflected in the RBLC, a limit of 0.08 lb/MMBtu is achievable using SCR and low NO_X burners, and notes that EPA cites SCR as the basis for its proposed limit of 1.0 lb/MWh (equivalent to 0.11 lb/MMBtu). The commenter recommends an output-based standard equivalent to a heat-input based standard between 0.07 and 0.08 lb/MMBtu.

Response: EPA disagrees that the amended NSPS are inappropriate. EPA acknowledges that boiler types and control configurations are technically capable of achieving lower NO_X emissions. EPA has concluded that with advanced combustion controls, coal-fired electric utility steam-generating units are able to achieve a NO_X emissions rate of 1.0 lb/MWh (0.11 lb/MMBtu). The incremental cost of requiring SCR for reduction to 0.7 lb/MWh (0.08 lb/MMBtu) is approximately $5,000 per ton. The final NO_X standard is based on the best demonstrated technology taking into account costs, other environmental impacts, and additional energy requirements. Requiring SCR in addition to advanced combustion controls not only increases costs and decreases the net efficiency of the unit, but leads to ammonia emissions and catalyst disposal concerns. States and BACT permitting process are still capable of requiring additional controls as appropriate.

NO_X Control for Lignite-Fired Steam-Generating Units

Comment: Several commenters disagree with EPA's assessment of the feasibility of meeting the proposed NO_X limit for lignite-fired boilers. The commenters disagree with EPA's assessment that units burning lignite can meet the proposed NO_X limit with either SCR or fluidized bed combustors and SNCR because EPA is specifying a boiler design that has never been built larger than 300 MW and is generally no larger than 100 MW. According to the commenter, this violates CAA section 111(b)(5) which prohibits setting a standard based upon a particular technology. One commenter states that information was provided to EPA prior to proposal suggesting that pore pluggage of SCR catalysts makes the proposed limit of 1.0 lb/MWh unachievable at lignite units. According to the commenter, there were no commercial applications of SCR (retrofit or new unit applications) for either northern or southern lignite. One commenter cites published research showing SCR technology ineffective for NO_X reduction from lignite-fired steam-generating units and states that it is unlikely that any new pulverized coal units using Fort Union lignite would install SCR technology to reduce NO_X emissions. The commenter also states that combustion controls, the only effective means to reduce NO_X emissions at some lignite-fired units, have been problematic for Fort Union lignite. The commenter recommends retaining the current NSPS of 1.6 lb/MWh for units burning Fort Union lignite.

Response: EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.

The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power plant showed acceptable results from Gulf Coast lignite. In addition, two recent permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak Grove facilities) propose to use SCR to control NO_X emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications.

Pore plugging and binding of a catalyst is a common problem experienced by pilot test facilities. In full scale installations, this concern is addressed during the SCR design stage. The methods used to avoid this problem include duct design to promote ash fallout prior to the SCR, catalyst reactor design to avoid ash buildup, and on-line cleaning methods (soot blowers and sonic horns).

In addition, the use of SCR is not required to comply with the amended NO_X standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_X/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_X reduction to comply with the amended NO_X standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.

Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_X emissions limit of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed.

Selection of SO_2 Emission Limit

Comment: One group of commenters state that EPA's proposed SO_2 standard for electric utility steam-generating units violates CAA section 111 because it does not reflect BDT for this source category. EPA also did not consider foreign experience or advanced scrubber designs, which indicate lower SO_2 limits have been achieved and are achievable. The processes that have demonstrated greater than 98 percent SO_2 removal and for which vendors offer guarantees greater than 98 percent are the magnesium-enhanced lime ("MEL") flue gas desulfurization (FGD) process, the Chiyoda CT–121 bubbling jet reactor, and circulating fluidized bed scrubbers. Further, design enhancements and additives are available that can increase SO_2 removal efficiencies above 98 percent for other technologies within this general class. Also, EPA did not consider the use of coal washing in its determination.

Response: EPA has concluded that 98 percent control is possible with certain control and boiler configurations under ideal conditions. The amended SO_2 standard is based on a 30-day average that includes the variability that occurs from non-ideal operating conditions. The best long-term SO_2 control performance data that EPA has available

are for the Harrison, Conemaugh, Northside, Clover, and similar facilities. The amended standards are based on operational data from these facilities. EPA has concluded that this level of control is achievable for a broad range of coal and boiler types.

Comment: One group of commenters state that to meet the requirements of CAA section 111, EPA must establish a SO_2 limit of no more than 0.9 lb/MWh for all utility steam-generating units. Alternatively, if EPA finds that this standard would be cost-prohibitive for high sulfur coal, then it should either set emissions limits on a sliding scale that reflects BDT for coals of increasing sulfur content, or establish both stringent emissions limits and stringent percentage reduction requirements that would apply simultaneously. The commenters' review of proposed and final emission limits in recent permits and permit applications for 32 recent coal-fired steam-generating unit projects found 9 units with emissions limits of 0.10 lb/MMBtu or lower (0.95 lb/MWh or lower, assuming 36 percent efficiency) and 22 units with emission limits of 0.13 lb/MMBtu or lower (1.2 lb/MWh or lower).

One commenter states that the standard for SO_2 is insufficiently stringent and does not reflect the best system of emission reduction as required by CAA section 111. The commenter provides the following supporting rationale:

- About 70 percent of coals in use can meet the proposed limit with add-on controls. The data before EPA supports a limit at the low end of the range being considered by EPA (0.90–2.0 lb/MWh) rather than the proposed level (2.0 lb/MWh), which is at the top of the range.
- All coals currently in use can meet a more stringent standard, e.g., 88 percent of coals currently in use can meet 1.1 lb/MWh without pretreatment and using wet lime FGD that consistently achieves a 97 percent reduction; EPA has determined that reductions greater than 98 percent are demonstrated.
- For high sulfur coals, other technologies are available, e.g., IGCC technology which is capable of reductions of over 99 percent. The highest sulfur coals (uncontrolled level of 7.92 lb/MMBtu) can meet 1.1 lb/MWh using technologies that reduce sulfur levels by 99 percent. Other options for meeting more stringent standards include coal washing and blending with low sulfur coals.
- Actual 2003 emissions data show 25 plants with scrubbers achieving emissions at or below 0.10 lb/MMBtu (data attached to commenter's submittal). EPA's BACT/LAER clearinghouse establishes permitted levels for new scrubbers below the proposed standard and as low as 0.06 lb/MMBtu; IGCC units show even lower permitted levels, 0.03 and 0.032 lb/MMBtu.
- Vendors of scrubber report removal efficiencies of 99.5 percent of sulfur from high sulfur coal (as high as 4 percent) achieving SO_2 emission rates of 0.04 lb/MMBtu. The commenter attached a supporting report by a vendor of scrubber equipment.
- New Source Review (NSR) enforcement settlements reflect better emission rates than 0.21 lb/MMBtu even at existing plants. EPA routinely obtains commitments for FGD retrofits to meet rates of 0.100 to 0.130 lb/MMBtu. The commenter attached supporting consent decrees.
- EPA's proposed standards rely on an estimate that new plants will operate at a 36 percent gross efficiency even though the top 10 percent of existing units operate at 38 percent. This is unreasonable given that the standards will govern new PC plants, with new supercritical plants able to achieve a net efficiency of 45 percent and a gross efficiency of 40 percent.

One commenter states that new coal-fired units can achieve SO_2 emission limits of 0.500 to 1.5 lb/MWh depending on sulfur content. The commenter supports lower SO_2 limits for lower sulfur coal and suggests that this can be done by maintaining a percent reduction requirement or setting a range of SO_2 limits based on sulfur content of coal. The commenter recommends that where a percent reduction limit is used, it should be in addition to the emission rate limit.

One commenter recommends an output-based limit equivalent to a heat-input based limit of 0.10 lb/MMBtu. Based on a survey of EPA's RBLC for recent permitting decisions, permitted SO_2 levels of 0.022 to 0.12 lb/MMBtu, are common State requirements. EPA's argument for a higher limit to account for the highest-sulfur coal is flawed because industry can use lower sulfur coal or use technologies to reduce SO_2 emissions beyond the proposed level.

Response: EPA acknowledges that certain boiler and coal configurations are technically capable of achieving SO_2 emissions rates of 1.0 lb/MWh. The NSPS are based on limits that can be achieved on a consistent basis for a broad range of boiler and coal types. High sulfur coals are an important part of the United States energy resources, and spray dryers for SO_2 control are important in locations with limited water resources. EPA has concluded that it is vital that the amended NSPS preserve the use of both high sulfur coals and spray dryers. Therefore, EPA is amending the SO_2 standard to allow units greater flexibility in complying with the final SO_2 standard. The amended SO_2 standard is either 1.4 lb/MWh or 95 percent reduction on a 30-day rolling average. The numerical limit is aggressive, but preserves the ability of approximately half the coals presently used in the United States to use spray dryers. The percent maximum reduction requirement is similarly aggressive, but preserves the ability of units to burn high sulfur coals. Based on the sulfur content of coals presently being burned in the United States, EPA has concluded that the majority of new units will comply with the 1.4 lb/MWh standard, but has provided the maximum percent reduction requirement to address the concerns of users of high sulfur coals. The BACT permitting process and states requirements are able to require additional controls as appropriate.

Comment: One commenter states that many scrubbers used for high sulfur coals—3 to 4 percent sulfur—will be unable to meet the proposed SO_2 limit of 2.0 lb/MWh on a consistent basis. According to the commenter, EPA has based their decision on a single, high performance magnesium-enhanced lime scrubber, i.e., the Harrison facility in Pennsylvania. The commenter states that the specialty agent used at the unit may not be broadly available and brings into question whether the SO_2 levels being attained at this plant can be sustained long term. The commenter also states that EPA's use of a scrubber at a single facility as the basis for the SO_2 limit is in conflict with CAA section 111(b)(5), which prohibits setting a standard based upon a particular technology.

The commenter continues by stating that there is considerable uncertainty that the high removal efficiency that would be required for high sulfur coals can consistently and broadly be achieved. According to the commenter, coals with sulfur content exceeding 2.5 percent would require removal efficiencies of up to 98 percent; for these coals, wet scrubbers are the sole option and uncertainties in meeting the NSPS may dissuade some from using such coals.

Response: The final rule amendments allow units to either comply with an output-based limit of 1.4 lb/MWh or demonstrate 95 percent reduction. The maximum percent reduction requirement is achievable for multiple boiler and control configurations and addresses concerns of the use of high sulfur fuels.

Particulate Matter Emission Limit

Comment: One commenter states that fabric filters, the technology on which the proposed PM emission standard is based, is problematic with coals whose sulfur content exceeds 1.5 percent. With only 134 of 1,250 U.S. coal-fired power plants using fabric filters, the commenter notes that with the exception of a limited number of applications on small atypical boilers, there are no fabric filters in operation on plants firing sulfur greater than 2.0 percent by weight. The commenter cites an example of a plant that encountered problems after installing a fabric filter on a unit burning medium-or high-sulfur coal. For this reason, the commenter states that EPA's proposed PM standard is neither achievable nor adequately demonstrated for all coals.

Response: In general, EPA disagrees with the comment that the use of fabric filters to control PM emissions is problematic for electric utility steam generating units firing coals with sulfur contents exceeding 1.5 percent. The example cited by the commenter is for a retrofit application of a fabric filter at an existing facility for which the temperature of the flue gas in the fabric filter unit was not maintained above the acid dew point. Consequently, acid mist formed in the flue gas, condensed on the bags and internal components of the unit, and adversely impacted the performance of the control device. Based on discussions with fabric filter equipment suppliers, EPA has concluded that a similar problem should not occur in fabric filters installed on new and reconstructed facilities because of the capability at these sites to incorporate design options that will maintain the temperature of the flue gas passing through the fabric filter at levels above the acid dew point of the flue gas. These options include use of high temperature bags and injection of hydrated lime to lower the acid dew point of the flue gas. The Department of Energy sponsored two demonstration projects (SNOX Flue Gas Cleaning Demonstration Project (SNOX) and SO_X-NO_X-RO_X-Box Flue Gas Cleanup Demonstration Project (SNRB) projects) that successfully used fabric filters for PM control for electric utility steam generating units burning high sulfur coal, potential SO_2 emissions of 5 and 6 lb/MMBtu, respectively. In addition, two recent permit applications propose to use fabric filters for PM control while burning relatively high sulfur coals. The Longview power plant in West Virginia is proposing to burn 2.5 percent sulfur coal, and the Elm Road plant is proposing to burn coal with potential SO_2 emissions of 4 lb/MMBtu.

EPA recognizes that in certain site-specific situations where an existing electric utility steam generating unit becomes subject to the NSPS because of modifications to the unit, replacement of an electrostatic precipitator (ESP) with a fabric filter could be problematic. Not all locations may be able to cost-effectively maintain the temperature of the flue gas in a fabric filter above the acid dew point of the flue gas because of existing site conditions and space constraints. Therefore, EPA decided it is appropriate to establish a separate PM standard for modified sources subject to subpart Da, 40 CFR part 60. Owners and operators of modified electric utility steam generating units subject to the NSPS are given the option of meeting either a 0.015 lb/MMBtu or 99.8 percent reduction standard. ESPs can be modified to cost-effectively achieve this level of control.

Comment: One commenter takes issue with EPA's proposed input-based standard for PM emissions. According to the commenter, although EPA determined that ESPs and fabric filters are the best demonstrated technology for controlling filterable particulate matter, EPA's justification for the revised PM limit is based on three plants where fabric filtration is used. The commenter also states that of the three plants, two use fluidized bed boilers, which use limestone as an active bed material, significantly altering the nature of the PM generated for collection. The commenter states that the record does not support the proposed NSPS for PM for ESPs or that fluidized bed combustors are appropriate units on which to base PM standards for pulverized coal steam generating units, which are projected to make up the majority of new units.

Response: EPA has gathered additional stack test data that indicates an ESP could be used by the majority of coal types to comply with the final rule amendments. Based on ESP cost models, they are often less expensive than fabric filters for high sulfur applications. Additional information is available in the PM control cost memorandum.

Comment: One group of commenters state that the proposed opacity limit does not reflect BDT because the proposed rule retains the existing opacity limit of 20 percent. The commenters state that this limit is over 20 years old, and is not based on the performance of modern baghouse control systems. Because EPA has acknowledged in the proposed rule that the former 0.03 lb/MMBtu PM limit should at least be halved to 0.015 lb/MMBtu, there should be a proportionate halving of the opacity limit, from 20 percent to 10 percent. Ten percent opacity can be easily and continuously attained by subpart Da, 40 CFR part 60, facilities using appropriate control technology. There are existing power plants around the country with BACT limits of 10 percent for opacity, including the Sevier Power Company—Sigurd plant in Utah, Intermountain Power in Utah, and Plum Point Energy in Arkansas.

Response: Since opacity is used as an indication on PM emissions, EPA has provided sources with two options to demonstrate continuous compliance with the amended PM standard. Sources may elect to install and operate PM CEMS and demonstrate compliance each boiler operating day. For these units, opacity monitoring shall no longer be required. Units that do not install PM CEMS shall perform stack tests to demonstrate compliance and shall still be subject to the existing 6-minute opacity limit. In addition, sources shall use bag leak detectors or monitor ESP parameters in addition to developing a site-specific opacity trigger level that is based on the opacity during the stack test. Sources that deviate from this opacity or other parameter are required to perform a stack test within 60 days of the deviation. Stack opacity characteristics are different for fabric filters and ESP. Therefore, EPA has concluded that a site-specific opacity trigger is the best approach to monitor continuous compliance.

B. Industrial-Commercial-Institutional and Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subparts Db and Dc)

Comment: Several commenters opposed both the proposed single SO_2 limit of 0.24 lb/MMBtu heat input and the limit of either 0.15 lb/MMBtu heat input or 95 percent reduction for a variety of reasons. Several commenters believed that these approaches would discourage the use of high sulfur coals found in the Midwest and would be difficult to meet consistently for circulating fluidized bed boilers and boilers burning low sulfur coal. They also stated that industrial boilers cannot routinely achieve high percent reductions of 95 percent or more, as would be required to meet these standards, because of variations in coal quality and operational variations due to fluctuations in steam demand. Also, meeting 95 percent reduction would not be feasible for existing units that are modified. Three of the commenters recommended adopting the same SO_2

standard as subpart Da, 40 CFR part 60 (90 percent reduction with a 70 percent reduction for units that demonstrate emissions below 0.20 lb/MMBtu heat input). Two commenters recommended retaining the current 90 percent SO_2 reduction requirement with an alternative emission limit of 0.24 lb/MMBtu heat input. One commenter supported EPA's decision that the current SO_2 emission limits in subparts Db and Dc of 40 CFR part 60 should not be amended because option 1 and 2 would impose unacceptable compliance costs and are not warranted. One commenter also opposed reducing the SO_2 limit for units with heat input capacities of 10–75 MMBtu/h.

Several commenters maintained that the changes to the SO_2 limit to remove the percent reduction requirement should apply to existing units as well as new units. Excluding existing units from the change would provide a disincentive to use low sulfur coal and would not provide relief for existing compliance problems. Many existing boilers were designed to achieve 90 percent reduction using high sulfur coals. An existing unit that wanted to switch to low sulfur coal would have difficulty in meeting a 90 percent requirement using existing control equipment. Also, circulating fluidized bed (CFB) boilers that use low sulfur coal have had difficulty in achieving a 90 percent reduction consistently. The technical impossibility of measuring uncontrolled SO_2 emissions at a CFB unit creates an inherent difficulty in adjusting limestone injection rate to accommodate short-term variations in coal sulfur content. One such unit that burns low sulfur coal has been cited for short-term violations of the NSPS even though average emissions were in the range of 0.13 lb/MMBtu (0106).

Response: After considering all the comments and additional information provided by commenters, we have decided to provide industrial units the following options. Units presently subject to the NSPS and modified units may reduce SO_2 emissions by 90 percent or meet an SO_2 emission limit of 0.20 lb/MMBtu heat input. New and reconstructed units that become subject to the NSPS after February 28, 2005, may reduce SO_2 emissions by 92 percent or meet an SO_2 emission limit of 0.20 lb/MMBtu heat input. This approach will be more stringent than the existing subpart Db, 40 CFR part 60, requirements, and at the same time allow units with difficulty in achieving high levels of SO_2 control to overcome compliance demonstrations problems by burning low sulfur fuels.

IV. Impacts of the Final Rule?

A. What are the impacts for electric utility steam generating units (40 CFR part 60, subpart Da)?

We estimate that 5 new electric utility steam generating units will be installed in the United States over the next 5 years and affected by the final rule. All of these units will need to install add-on controls to meet the PM, SO_2, and NO_X limits required under the final rule. However, these boilers will already be required to install add-on PM, SO_2, and NO_X controls to meet the reduction requirements of the existing NSPS. Compared to the existing NSPS, the incremental PM, SO_2, and NO_X reductions resulting from the final rule will be 530 tons of PM, 8,400 tons of SO_2, and 1,400 tons of NO_X. Using this comparison, the annualized cost of the final utility amendments are $4.4 million.

Using this comparison, we expect the final rule to result in an increase in electrical supply generated by unaffected sources (e.g., existing electric utility steam generating units), we have concluded that this will not result in higher NO_X, SO_2, and PM emissions from these sources. Other emission control programs such as the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and PSD/NSR already promote or require emission controls that would effectively prevent emissions from increasing. All the emissions reductions estimates and assumptions have been documented in the docket to the final rule.

A more accurate assessment of the emissions reductions and annualized costs of the final utility amendments include other regulatory programs that are presently requiring controls beyond what is required by the existing NSPS. The BACT permitting process requires new sources to install controls at or beyond what the final NSPS amendments require. In addition, the recently finalized CAIR and CAMR rules, along with the proposed revisions to ambient particulate matter standards, will push permits even lower. The amended NSPS reflect the levels of control presently being required by these other programs. Therefore, the actual environmental benefits and cost impacts of the final rule are essentially zero. A more detailed discussion of the cost and emissions impacts of the amended NSPS is available in the docket.

B. What are the impacts for industrial-commercial-institutional boilers (40 CFR part 60, subparts Db and Dc)?

We estimate that approximately 186 new industrial-commercial-institutional boilers will be installed in the United States over the next 5 years and affected by the final rule. All of these units will need to install add-on controls to meet the PM and SO_2 limits required under the final rule. However, these new boilers will already be required to install add-on PM and SO_2 controls to meet the existing NSPS. The new source requirements under the maximum achievable control technology (MACT) program and PSD/NSR require new units presently to install controls beyond what is required by the existing NSPS.

Wood-fired boilers are the only industrial sources that could potentially use the alternative compliance limit in the boiler MACT and would not be required to meet the new source MACT limit. We estimate that 17 new wood-fired boilers will be installed in the United States over the next 5 years and affected by the final rule. Using the existing NSPS as a baseline, the additional annualized costs are $2.2 million, and the PM emissions reductions are 930 tons. EPA has concluded that new wood-fired units will not use the compliance alternatives available in the boiler MACT and that they will comply with the new source PM limit of 0.025 lb/MMBtu. Due to PSD/NSR and the limited applicability of the alternate compliance limit to new units, it will primarily only be used by existing wood-fired boilers. Thus, we concluded that the PM and SO_2 reductions and costs resulting from the final rule will essentially be zero.

C. What are the economic impacts?

Even though actual costs and benefits are essentially zero, EPA prepared an economic impact analysis comparing the existing NSPS with the amended NSPS to evaluate the impacts the final rule will have on electric utilities and consumers of goods and services produced by electric utilities. The analysis showed minimal changes in prices and output for products made by the industries affected by the final rule. The price increase for affected output is less than 0.003 percent, and the reduction in output is less than 0.003 percent for each affected industry. Estimates of impacts on fuel markets show price increases of less than 0.01 percent for petroleum products and natural gas, and price increases of 0.04 and 0.06 percent for base-load and peak-load electricity, respectively. The price

of coal is expected to decline by about 0.002 percent, and that is due to a small reduction in demand for this fuel type. Reductions in output are expected to be less than 0.02 percent for each energy type, including base-load and peak-load electricity.

D. What are the social costs and benefits?

The social costs of the final rule are estimated at $0.4 million (2002 dollars). Social costs include the compliance costs, but also include those costs that reflect changes in the national economy due to changes in consumer and producer behavior in response to the compliance costs associated with a regulation. For the final rule, changes in energy use among both consumers and producers to reduce the impact of the regulatory requirements of the rule lead to the estimated social costs being less than the total annualized compliance cost estimate of $6.5 million. The primary reason for the lower social cost estimate is the increase in electricity supply generated by unaffected sources (*e.g.*, existing electric utility steam generating units), which offsets mostly the impact of increased electricity prices to consumers. The social cost estimates discussed above do not account for any benefits from emission reductions associated with the final rule.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

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

B. Paperwork Reduction Act

The final rule amendments do not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The final rule amendments result in no changes to the information collection requirements of the existing standards of performance and would have no impact on the information collection estimate of project cost and hour burden made and approved by OMB during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. The OMB has previously approved the information collection requirements contained in the existing standards of performance (40 CFR part 60, subparts Da, Db, and Dc) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, at the time the standards were promulgated on June 11, 1979 (40 CFR part 60, subpart Da, 44 FR 33580), November 25, 1986 (40 CFR part 60, subpart Db, 51 FR 42768), and September 12, 1990 (40 CFR part 60, subpart Dc, 55 FR 37674). The OMB assigned OMB control numbers 2060–0023 (ICR 1053.07) for 40 CFR part 60, subpart Da, 2060–0072 (ICR 1088.10) for 40 CFR part 60, subpart Db, 2060–0202 (ICR 1564.06) for 40 CFR part 60, subpart Dc. Copies of the information collection request document(s) may be obtained from Susan Auby by mail at U.S. EPA, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460, by e-mail at *auby.susan@epa.gov*, or by calling (202) 566–1672. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr*.

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

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of the final rules on small entities, small entity is defined as follows: (1) A small business that is an ultimate parent entity in the regulated industry that has a gross annual revenue less than $6.5 million (this varies by industry category, ranging up to $10.5 million for North American Industrial Classification System (NAICS) code 562213 (VSMWC)), based on Small Business Administration's size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule amendments on small entities, we conclude that this action will not have a significant economic impact on a substantial number of small entities. We have determined for electric utility steam generating units, based on the existing inventory for the corresponding NAICS code and presuming the percentage of entities that are small in that inventory (estimated to be 3 percent) is representative of the percentage of small entities owning new utility boilers in the 5th year after promulgation, that at most, one entity out of five new entities in the industry may be small entities and thus affected by the final rule amendments.

We have determined for industrial-commercial steam generating units,

based on the existing industrial boilers inventory for the corresponding NAICS codes and presuming the percentage of small entities in that inventory is representative of the percentage of small entities owning new wood-fueled industrial boilers in the 5th year after promulgation, that between two and three entities out of 17 in the industry with NAICS code 321 and 322 may be small entities, and thus affected by the final rule amendments.

Based on the boiler size definitions for the affected industries (subpart Db of 40 CFR part 60: greater than or equal to 100 MMBtu/h; subpart Dc of 40 CFR part 60: 10–100 MMBtu/h), EPA determined that the firms being affected were likely to fall under the subpart Dc of 40 CFR part 60 boiler category. These two or three affected small entities are estimated to have annual compliance costs between $70 and $105 thousand which represents less than 5 percent of the total compliance cost for all affected wood-fired industrial boilers. Based on the average employment per facility data from the U.S. Census Bureau, for the corresponding NAICS codes under the subpart Db of 40 CFR part 60 and subpart Dc of 40 CFR part 60 categories, the compliance cost of these facilities is expected to be less than 1 percent of their estimated sales. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis in the docket.

Although the final rule amendments will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of the final rule amendments on small entities. In the final rule amendments, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. This provision should reduce the size of small entity impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if EPA publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, EPA must develop a small government agency plan under section 203 of the UMRA. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA's regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final rule amendments contain no Federal mandates that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, the final rule amendments are not subject to the requirements of section 202 and 205 of the UMRA. In addition, we determined that the final rule amendments contain no regulatory requirements that might significantly or uniquely affect small governments because the burden is small and the regulation does not unfairly apply to small governments. Therefore, the final rule amendments are not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

The final rule amendments do not have federalism implications. They will not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The final rule amendments will not impose substantial direct compliance costs on State or local governments, it will not preempt State law. Thus, Executive Order 13132 does not apply to the final rule amendments.

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

Executive Order 13175, (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications." "Policies that have Tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on relationship between the Federal Government and the Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes."

The final rule amendments do not have tribal implications, as specified in Executive Order 13175. They will not have substantial direct effects on tribal governments, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the final rule amendments.

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

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

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety

risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. The final rule amendments are not subject to Executive Order 13045 because they are based on technology performance and not on health and safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use

This action is not a "significant energy action," as defined in Executive Order 13211, because it is not likely to have a significant adverse effect on the supply, distribution, or energy use. Further, we concluded that this action is not likely to have any adverse energy effects.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. No. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

Today's action does not involve any new technical standards or the incorporation by reference of existing technical standards. Therefore, the consideration of voluntary consensus standards is not relevant to today's action.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing today's action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. Today's action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule amendments will be effective February 27, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: February 9, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of Federal Regulations is amended as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, et seq.

Subpart Da—[Amended]

■ 2. Section 60.40Da is amended by revising paragraph (b) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

* * * * *

■ 3. Section 60.41Da is amended by revising the definitions of "Boiler operating day," "Cogeneration," "Electric utility steam-generating unit," and "Gross output" and by adding in alphabetical order the definitions of "ISO conditions" and "Petroleum" to read as follows:

§ 60.41Da Definitions.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

Cogeneration, also known as "combined heat and power," means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Electric utility steam-generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

* * * * *

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

* * * * *

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60

percent, and a pressure of 101.3 kilopascals.

* * * * *

Petroleum means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

* * * * *

■ 4. Section 60.42Da is amended by revising the introductory text in paragraph (a) and adding paragraphs (c) and (d) to read as follows:

§ 60.42Da Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

* * * * *

(c) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

■ 5. Section 60.43Da is amended by revising the introductory text in paragraphs (a) and (b) and adding paragraphs (i), (j), and (k) to read as follows:

§ 60.43Da Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

* * * * *

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

* * * * *

(i) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that

contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

■ 6. Section 60.44Da is amended by revising paragraph (d) and adding paragraphs (e) and (f) to read as follows:

§ 60.44Da Standard for nitrogen oxides.

* * * * *

(d)(1) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO_2) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under § 60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO_2) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO_2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under § 60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

■ 7. Section 60.48Da is amended by revising paragraphs (g), (i), (k) introductory text, (k)(1) introductory text, (k)(1)(iv), (k)(2) introductory text, and adding paragraphs (m), (n), (o), and (p) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average SO_2 and NO_X emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during

startup, shutdown, malfunction (NO_X only), or emergency conditions (SO_2) only.

(2) Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

* * * * *

(i) *Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), or (f).* The owner or operator of an affected facility subject to § 60.44Da(d)(1) or (e)(1) shall calculate NO_X emissions by multiplying the average hourly NO_X output concentration, measured according to the provisions of § 60.49Da(c), by the average hourly flow rate, measured according to the provisions of § 60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of § 60.49Da(k).

* * * * *

(k) *Compliance provisions for duct burners subject to § 60.44Da(d)(1) or (e)(1).* To determine compliance with the emission limitation for NO_X required by § 60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO_X emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

* * * * *

(iv) Compliance with the applicable NO_X emission limitation in § 60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable NO_X emission limitation in § 60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

* * * * *

(m) *Compliance provisions for sources subject to § 60.43Da(i)(1)(i) or (j)(1)(i).* The owner or operator of an affected facility subject to § 60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO_2 emissions by multiplying the average hourly SO_2 output concentration, measured according to the provisions of § 60.49Da(b), by the average hourly flow rate, measured according to the provisions of § 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.49Da(k).

(n) *Compliance provisions for sources subject to § 60.42Da(c)(1).* The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of § 60.49Da(t), by the average hourly flow rate, measured according to the provisions of § 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to § 60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in § 60.50Da to demonstrate compliance by the applicable date specified in § 60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with § 60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in § 60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in

§ 60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in § 60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

■ 8. Section 60.49Da is amended by revising paragraphs (a), (b)(2), (f), (k)(3), (l), and (o), and adding paragraphs (t), (u), and (v) to read as follows:

§ 60.49Da Emission monitoring.

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

* * * * *

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

* * * * *

(k) * * *

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

* * * * *

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under § 60.42Da, § 60.43Da, § 60.44Da, or § 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

* * * * *

(o) The owner or operator of a duct burner, as described in § 60.41Da, which is subject to the NO_X standards of § 60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to

measure the flow of exhaust gases discharged to the atmosphere.

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da(c)(1) shall install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under § 60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in § 60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in § 60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under § 60.42Da(a)(1) or § 60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of § 60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

■ 9. Section 60.50Da is amended by revising paragraph (g)(2) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(g) * * *

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \quad \text{(Eq. 1)}$$

Where:

ER_{cogen} = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

V_{grid} = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$ = Amount of energy converted to steam for process use over the same compliance period (MWh).

* * * * *

Subpart Db—[Amended]

■ 10. Section 60.40b is amended by revising paragraph (i) and adding paragraphs (k) and (l) to read as follows:

§ 60.40b Applicability and delegation of authority.

* * * * *

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(k) Any facility covered by subpart Eb or subpart AAAA of this part is not covered by this subpart.

(l) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

■ 11. Section 60.41b is amended by adding the definition of "Cogeneration" in alphabetical order and revising the definition of "Very low sulfur oil" to read as follows:

§ 60.41b Definitions.

* * * * *

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Very low sulfur oil for units constructed, reconstructed, or modified on or before February 28, 2005, means an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without sulfur dioxide emission control, has a sulfur dioxide emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

* * * * *

■ 12. Section 60.42b is amended by revising paragraphs (a) introductory text, (b), (d) introductory text, and (d)(3) and by adding paragraphs (d)(4) and (k) to read as follows:

§ 60.42b Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), (d), (j), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction,

reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential sulfur dioxide emission rate (90 percent reduction) and the emission limit determined according to the following formula:

* * * * *

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential sulfur dioxide emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

* * * * *

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever comes first, no owner or operator of an affected facility listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/million Btu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/million Btu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4).

* * * * *

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat input to the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat input to the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with any other gaseous fuels.

* * * * *

(k) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction or reconstruction after February 28, 2005, and that combusts coal, oil, gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential sulfur dioxide emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input, except as provided in paragraphs (k)(1) or (k)(2). Affected facilities subject to this paragraph are also subject to paragraphs (e) through (g) of this section.

(1) Units firing only oil that contains no more than 0.3 weight percent sulfur or any individual fuel with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from all other sulfur dioxide emission limits in this paragraph.

(2) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 230 ng/J (0.54 lb/MMBtu) heat input if the affected facility combusts oil.

■ 13. Section 60.43b is amended by adding paragraph (h) to read as follows:

§ 60.43b Standard for particulate matter.

* * * * *

(h)(1) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5).

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur or other liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less is not subject to the PM or opacity limits in this section.

■ 14. Section 60.44b is amended by adding paragraph (l)(3) to read as follows:

§ 60.44b Standard for nitrogen oxides.

* * * * *

(l) * * *

(3) After February 27, 2006, units may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.46a (i)(1), and must monitor emissions according to § 60.47a(c)(1), (c)(2), (k), and (l).

■ 15. Section 60.45b is amended by revising the introductory text in paragraph (c) and adding paragraph (k) to read as follows:

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

* * * * *

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential sulfur dioxide emission rate (% P_s) and the sulfur dioxide emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

* * * * *

(k) Units that burn only oil that contains no more than 0.3 weight percent sulfur or fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining records of fuel supplier certifications of sulfur content of the fuels burned.

■ 16. Section 60.46b is amended by revising paragraphs (a) and (b) and adding paragraphs (i) and (j) to read as follows:

* * * * *

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

(a) The particulate matter emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction, and as specified in paragraphs (i) and (j) of this section. The nitrogen oxides emission standards under § 60.44b apply at all times.

(b) Compliance with the particulate matter emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) and (j).

* * * * *

(i) Units burning only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with a potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less may demonstrate compliance by maintaining fuel supplier certifications of the sulfur content of the fuels burned.

(j) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under § 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (j) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

(7) At a minimum, valid continuous monitoring system hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

■ 17. Section § 60.47b is amended by revising paragraphs (a) and (d), and adding paragraph (g) to read as follows:

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b),(f), and (g) of this section, the owner or operator of an affected facility subject to the sulfur dioxide standards under § 60.42b shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS)

for measuring sulfur dioxide concentrations and either oxygen (O_2) or carbon dioxide (CO_2) concentrations and shall record the output of the systems. The sulfur dioxide and either oxygen or carbon dioxide concentrations shall both be monitored at the inlet and outlet of the sulfur dioxide control device.

* * * * *

(d) The 1-hour average sulfur dioxide emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average sulfur dioxide emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly sulfur dioxide emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

* * * * *

(g) Units burning any fuel with a potential sulfur dioxide emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

■ 18. Section 60.48b is amended by revising paragraphs (a), (b) introductory text, (d), and adding paragraphs (j) and (k) to read as follows:

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

(a) The owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system, except as provided in paragraphs (j) and (k) of this section.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a nitrogen oxides standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

* * * * *

(d) The 1-hour average nitrogen oxides emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

* * * * *

(j) Units that burn only oil that contains no more than 0.3 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 140 ng/J (0.32 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(k) Owners or operators complying with the PM emission limit by using a PM CEMs monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The continuous monitoring systems specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

Subpart Dc—[Amended]

■ 19. Section 60.40c is amended by adding paragraphs (e), (f), and (g) to read as follows:

§ 60.40c Applicability and delegation of authority.

* * * * *

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not covered by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not covered by this subpart.

■ 20. Section 60.41c is amended by revising the definition of coal to read as follows:

§ 60.41c Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

* * * * *

■ 21. Section 60.42c is amended by revising paragraphs (a), (b) introductory text, and (b)(1) to read as follows:

§ 60.42c Standard for sulfur dioxide.

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: Cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO_2 reduction requirement specified in this paragraph and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8 of this part, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction), nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

* * * * *

■ 22. Section 60.43c is amended by adding paragraph (e) to read as follows:

§ 60.43c Standard for particulate matter.

* * * * *

(e)(1) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2) and (e)(3) of this section. Affected facilities subject to this paragraph, are also subject to the requirements of paragraphs (c) and (d) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under § 60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, gas, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On or after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter emissions in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

■ 23. Section 60.45c is amended by revising the introductory text in paragraph (a) and adding paragraphs (c) and (d) to read as follows:

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) and (d) of this section.

* * * * *

(c) Units that burn only oil containing no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) In place of particulate matter testing with EPA Reference Method 5, 5B, or 17, an owner or operator may elect to install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring particulate matter emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor particulate matter emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 shall install, calibrate, maintain, and operate a continuous emission monitoring system and shall comply with the requirements specified in paragraphs (d)(1) through (d)(13) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the continuous monitoring system if the owner or operator was previously determining compliance by Method 5, 5B, or 17 performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for particulate matter emissions as required under § 60.8 of subpart A of this part. Compliance with the particulate matter emission limit shall be determined by using the continuous emission monitoring system specified in paragraph (d) of this section to measure particulate matter and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19, section 4.1.

(6) Compliance with the particulate matter emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using continuous emission monitoring system outlet data.

(7) At a minimum, valid continuous monitoring system hourly averages shall be obtained as specified in paragraph (d)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (d)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid continuous emission monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (d)(7) of this section are not met.

(10) The continuous emission monitoring system shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the continuous emission monitoring system required by Performance Specification 11 in

appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA reference Method 3, 3A, or 3B, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

■ 24. Section 60.47c is amended by revising paragraph (a) and adding paragraphs (c) and (d) to read as follows:

§ 60.47c Emission monitoring for particulate matter.

(a) The owner or operator of an affected facility combusting coal, oil, gas, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system, except as specified in paragraphs (c) and (d) of this section.

* * * * *

(c) Units that burn only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels with potential sulfur dioxide emission rates of 230 ng/J (0.54 lb/MMBtu) heat input or less are not required to conduct PM emissions monitoring if they maintain fuel supplier certifications of the sulfur content of the fuels burned.

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.45c(d). The continuous monitoring systems specified in paragraph § 60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

■ 25. Section 60.48c is amended by revising paragraph (g) to read as follows:

§ 60.48c Reporting and recordkeeping requirements.

* * * * *

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

* * * * *

[FR Doc. 06–1460 Filed 2–24–06; 8:45 am]
BILLING CODE 6560–50–P

■ b. When using only banding to secure bundles, the following additional requirements apply.

■ 1. Use at least one band to encircle the length of the bundle and use at least one band to encircle the width of the bundle.

■ 2. Use tension sufficient to tighten and depress the edges of the bundle so that pieces do not slip out of the banding during transit and processing.

* * * * *

340 Standard Mail

* * * * *

345 Mail Preparation

* * * * *

2.0 BUNDLES

* * * * *

2.6 Preparing Bundles in Sacks

■ [Revise introductory text to refer to the new banding requirements as follows. Delete item b to remove the old banding requirements and renumber items c through f as items b through e. Make identical changes in 707.19.8 (for Periodicals).]

■ In addition to the standards in 2.5, mailers must prepare and secure bundles placed in sacks as follows.

* * * * *

■ [Switch 445.2.5 and 445.2.6 for Standard Mail parcels. Revise new 2.5 using the text in 335.2.4 above; revise new 2.6 using the text in 345.2.6 above.]

* * * * *

■ [Replace text in 705.8.5.11 with text in new 335.2.4 above for bundles on pallets. Delete 705.8.5.12; renumber 8.5.13 and 8.5.14 as new 8.5.12 and 8.5.13.]

* * * * *

Neva R. Watson,
Attorney, Legislative.

[FR Doc. 06–1703 Filed 2–23–06; 8:45 am]
BILLING CODE 7710–12–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–OAR–2002–0053, FRL–8025–9]
RIN 2060–AK35

Standards of Performance for Stationary Gas Turbines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; amendments.

SUMMARY: EPA is taking direct final action to revise certain portions of the standards of performance for stationary gas turbines. We are taking direct final action to revise the standards to clarify that EPA is not imposing new requirements for turbines constructed after 1977. Owners and operators of existing and new turbines may use monitoring that meets the pre-existing monitoring requirements. In addition, we have described a number of acceptable compliance monitoring options that owners and operators may elect to use for these units. We see making the amendments by direct final rule as non-controversial and anticipate no adverse comments.

DATES: The direct final rule amendments are effective on April 25, 2006 without further notice, unless EPA receives adverse comment by March 27, 2006 or a public hearing is requested. If EPA receives such comments, it will publish a timely withdrawal in the **Federal Register** indicating which provisions are being withdrawn due to adverse comment.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–OAR–2002–0053. All documents in the docket are listed on the *www.regulations.gov Web* site. Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, Docket ID No. EPA–OAR–2002–0053, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jaime Pagán, Combustion Group, Emission Standards Division (C439–01), U.S. EPA, Research Triangle Park, North Carolina 27711; telephone number (919) 541–5340; facsimile number (919) 541–5450; electronic mail address "*pagan.jaime@epa.gov.*"

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities potentially regulated by this action are those that own and operate stationary gas turbines, and are the same as the existing rule in 40 CFR part 60, subpart GG. Regulated categories and entities include:

Category	NAICS	SIC	Examples of regulated entities
Any industry using a stationary combustion turbine as defined in 40 CFR 60.331(a).	2211	4911	Electric services.
	486210	4922	Natural gas transmission.
	211111	1311	Crude petroleum and natural gas.
	211112	1321	Natural gas liquids.
	221	4931	Electric and other services, combined.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. If you have questions regarding the applicability of this action to a particular entity, consult the contact person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Comments. EPA is publishing the direct final amendments without prior proposal because we view the amendments as noncontroversial and anticipate no adverse comment. In the "Proposed Rules" section of this **Federal Register**, EPA is publishing a separate document that will serve as the proposal in the event that timely adverse comments are received. Comments may be submitted using the methods and following the instructions specified in the proposal published in the "Proposed Rules" section of today's **Federal Register**. If EPA receives adverse comment on the amendments, we will publish a timely withdrawal in the **Federal Register** indicating which provisions will become effective and which provisions are being withdrawn

due to adverse comment. EPA will address all public comments on the proposed rule in a subsequent final rule based on the proposed rule. Any of the distinct amendments in the direct final rule for which we do not receive adverse comment will become effective on the date set out above. EPA will not institute a second comment period on the direct final rule. Any parties interested in commenting must do so at this time.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is also available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the final rule will be posted on the TTN policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of the direct final rule amendments is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia by April 25, 2006. Under section 307(d)(7)(B) of the CAA, only an objection to the direct final rule amendments that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by the direct final rule amendments may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Organization of this document. The information presented in this preamble is organized as follows:

I. Background

Under section 111 of the Clean Air Act (CAA), 42 U.S.C. 7411, the EPA promulgated standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). The standards were promulgated on September 10, 1979 (44 FR 52798). Since that time, there have been many advances in the design of NO_X emission controls used in gas turbines, and additional test methods have been developed to measure emissions from gas turbines. As a result of these advances, we have had many requests for case-by-case approvals of alternative testing and monitoring procedures for gas turbines regulated under subpart GG of 40 CFR part 60. We promulgated the 2004 amendments to subpart GG of 40 CFR part 60 to codify the alternatives that have been routinely approved. Additionally, we were attempting to harmonize, where appropriate, the provisions of subpart GG of 40 CFR part 60 with the monitoring provisions of 40 CFR part 75, the continuous emission monitoring requirements of the acid rain program under title IV of the CAA, since many existing and new gas turbines are subject to both regulations.

On April 14, 2003, we published a direct final rule (68 FR 17990) and a parallel proposal (68 FR 18003) amending the standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). We stated in the preambles to the direct final rule and parallel proposal that if we received adverse comments on one or more distinct provisions of the direct final rule, we would publish a timely withdrawal of those distinct provisions in the **Federal Register**. The preamble to the proposal also stated that if a public hearing was requested by April 24, 2003, the hearing would be held on May 14, 2003, and the comment period would be extended until 30 days after the date of the public hearing. Since a public hearing was requested, the comment period was extended until June 13, 2003. The entire direct final rule was withdrawn in order to avoid the direct final rule becoming effective.

On July 8, 2004, we published a final rule (69 FR 41346) amending the standards of performance for stationary gas turbines (40 CFR part 60, subpart GG). On September 1, 2004, the Interstate Natural Gas Association of America filed a Petition for Review of EPA's final rule. Interstate Natural Gas Association of America v. EPA, No. 04–1296 (D.C. Cir.). In accordance with a settlement agreement in that case, EPA is promulgating the direct final rule, which contains certain revisions to the final rule published on July 8, 2004.

II. Today's Action

A. Monitoring Options

Under the original provisions of subpart GG, 40 CFR part 60, any affected unit with a water injection system to control NO_X emissions was required to install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. These operating parameters demonstrate that a turbine continues to operate under the same performance conditions as those documented during the initial and any subsequent compliance tests, thus providing reasonable assurance of compliance with the NO_X standard. Subpart GG of 40 CFR part 60, as originally promulgated, did not include NO_X monitoring requirements for gas turbines that did not use water injection to control NO_X.

The amendments finalized on July 8, 2004, were intended to codify several alternative testing and monitoring procedures for NO_X emissions that have routinely been approved by EPA, State, and local permitting authorities. The amendments were also intended to reflect changes in NO_X emission control technologies and turbine design since the standards were promulgated. We stated in the preamble to the 2004 amendments that nothing in the amendments was intended to impose new requirements for turbines constructed between 1977 and the effective date of the final rule amendments.

The 2004 amendments set forth several alternative methods for monitoring NO_X emissions that could be used by owners or operators of newer turbines (turbines put into operation since subpart GG of 40 CFR part 60 was originally promulgated) (40 CFR 60.334(b) through (f)). Some of these provisions presented NO_X monitoring options for turbines that use water or steam to control NO_X emissions (40 CFR 60.334(b) and (d)), while others presented NO_X monitoring options for turbines that do not use water or steam to control NO_X (40 CFR 60.334(c), (e), and (f)). For both newer turbines that use water or steam to control NO_X emissions and those that do not, these provisions were written using permissive language (the owner or operator "may" use a particular method) rather than obligatory language (the owner or operator "shall" use a particular method).

While we stated in the July 8, 2004, preamble to the final rule amendments that nothing in the amendments was intended to impose new requirements for newer turbines, the preamble also contained statements that may have implied that newer turbines that do not use water or steam to control NO_X emissions were required to install one of the types of monitoring devices described in the amendments. (See, e.g., response to comment at 69 FR 41352 ("We do not agree with the commenter's suggested clarification that the monitoring requirements should apply only to turbines that use steam or water injection to control NO_X emissions to comply with the NO_X standards under 40 CFR 60.332(a). * * * Although a turbine may be able to meet the NO_X emission standard with other control technologies, continuous monitoring is needed to ensure that the emission limit is being met at all times.").) Furthermore, while the final rule provisions governing newer turbines that do not use water or steam to control NO_X emissions were written using permissive language, the final rule, read in conjunction with the preamble language, could be interpreted to imply that owners or operators of such newer turbines were required to install one of the types of monitoring devices. In addition, other final rule provisions, namely 40 CFR 60.334(j) and 40 CFR 60.335(b)(8), appeared to support the reading of the NO_X monitoring standards as requiring that newer turbines not using water or steam to control NO_X must comply with one of the continuous monitoring options.

Because, contrary to our stated intent, the standards applying to newer turbines that do not use water or steam to control NO_X could be read to impose new monitoring requirements, we are revising particular provisions of the amended subpart GG of 40 CFR part 60 regulations to make clear that the enumerated monitoring methods are optional rather than mandatory. We have revised the amended standards at 40 CFR 60.334(c), (e), and (f) to clarify that the monitoring methods described in these provisions are options rather than requirements for turbines that do not use water or steam to control NO_X emissions.

We decided that it was not necessary to impose continuous monitoring requirements on turbines that do not use water injection to control NO_X because the NO_X emissions of these turbines are, in almost all instances, well below the 40 CFR part 60, subpart GG, NO_X emission limits. For example, most lean premix turbines and many diffusion-flame turbines do not need any add-on controls to meet the NO_X limit under subpart GG that can range from 75 to over 100 parts per million by volume NO_X, depending on the efficiency of the unit. It is very unlikely that the turbine will be found to be out of compliance with the NO_X limit. Thus, requiring the use of NO_X continuous emission monitoring systems (CEMS) is not appropriate. In addition, we have recently proposed standards of performance for new stationary combustion turbines in 40 CFR part 60, subpart KKKK, that will set new NO_X emissions limits and monitoring requirements. (70 FR 8314, February 18, 2005.) Thus, once the standards in subpart KKKK are final, the amendments to subpart GG of 40 CFR part 60 affect only gas turbines commencing construction, reconstruction, and modification after July 8, 2004, and prior to February 18, 2005, for newly constructed sources or 6 months after the date that subpart KKKK becomes final for reconstructed and modified sources.

B. Other Minor Revisions to the Rule Amendments

1. Revision to Language on Previously Approved Monitoring Procedures

The second sentence of amended 40 CFR 60.334(c) provided: "Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under 40 CFR 60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section." It has been brought to our attention that many alternative monitoring methods are approved by incorporation into permits, rather than through a petition process. Therefore, we have revised 40 CFR 60.334(c) to reflect that approval process. Furthermore, we have removed the word "continuously" and the final phrase of 40 CFR 60.334(c) because monitoring methods other than the continuous monitoring methods described in 40 CFR 60.334(a) and the first sentence of 40 CFR 60.334(c) have been approved by EPA, State, and local permitting authorities. In addition, the last sentence of 40 CFR 60.334(e) is being revised to reflect the fact that other monitoring methods, including periodic testing, have been approved by EPA, State, and local authorities for regulated turbines that do not use water and steam to control NO_X emissions.

2. Clarification of the Types of New Turbines Being Referred to in 40 CFR 60.334(f) Introductory Text

The introductory text to 40 CFR 60.334(f) described parametric monitoring options that could be used by new turbines. We added text to clarify our intent that this provision applies to turbines that commence construction after July 8, 2004, which do not use water or steam to control NO_X emissions.

3. Modification of the Reference to "Lean Premixed (Low-NO_X) Combustion Mode" in 40 CFR 60.334(f)(2)

Section 60.334(f)(2) described an acceptable continuous parameter monitoring option for turbines that do not use water or steam to control NO_X as follows: "For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NO_X) combustion mode." The petitioner has asserted that the term "lean premixed (low-NO_X) combustion mode" is not clearly defined, especially for units that are in load following applications or operating with short-duration load variability. Furthermore, current generation industrial turbines are not likely to exceed the new source performance standard (NSPS) emission limit even when operating in a transition mode. We believe that shortening this phrase to simply "low-NO_X mode" is a better indicator of acceptable emissions performance in compliance with the emission limit.

4. Other Minor Revisions to Reflect the Fact That the Described Monitoring Methods Are Optional for Turbines That Do Not Use Water or Steam To Control NO_X Emissions

For the same reasons that we modified 40 CFR 60.334(c), (e), and (f) to reflect the fact that the monitoring methods are options rather than requirements for the newer turbines in question, we revised the introductory text of 40 CFR 60.334(j), 60.334(j)(1)(iv), and 40 CFR 60.335(b)(8) to reflect that these monitoring methods are optional rather than required.

5. Addition of References to States as Permitting Authorities

We have revised 40 CFR 60.334(c) and (e) by adding a reference to State permitting authorities, to reflect the fact that State permitting authorities, in addition to EPA and local permitting authorities, are in some instances the appropriate authorities to approve alternative monitoring procedures.

6. Correction of an Inadvertent Error in 40 CFR 60.334(j)(5) That Resulted in Changes to the Frequency of Submittals of Excess Emissions Reports

Excess emissions reports for affected turbines are due semi-annually as required under 40 CFR 60.7(c). Only turbines that qualify under the "ice fog" exemption (40 CFR 60.334(j)(3)) are required to submit quarterly reports. When revising 40 CFR 60.334 in the July 8, 2004, final rule, we inadvertently stated in 40 CFR 60.334(j)(5) that the reports required under 40 CFR 60.7 shall be filed quarterly rather than semi-annually. In this action, we are revising 40 CFR 60.334(j)(5) to correct this inadvertent error.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

It has been determined that today's action is not a "significant regulatory action" under the terms of Executive Order 12866 and is, therefore, not subject to Executive Order 12866 review.

B. Paperwork Reduction Act

Today's action does not impose any new information collection burden. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9.

Today's action contains no revisions to the information collection requirements of the current NSPS that would increase the burden to sources, and the currently approved OMB information collection requests are still in force for the final rule.

C. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with today's action.

For purposes of assessing the impacts of today's action on small entities, small entity is defined as: (1) A small business whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kilowatt per hour (kW-hr) per year of electricity usage, depending on the size definition for the affected North American Industry Classification System (NAICS) code; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. It should be noted that small entities in six NAICS codes may be affected by the final rule, and the small business definition applied to each industry by NAICS code is that listed in the Small Business Administration size standards (13 CFR part 121).

After considering the economic impacts of today's action on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. This conclusion is based on the fact that the direct final rule does not create, modify nor eliminate any of the requirements in the 40 CFR part 60, subpart GG regulations. Furthermore, the stringency of the emission standards is not affected by this action.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective, or least burdensome alternative that achieves the objective of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that today's action contains no Federal mandates that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Thus, the final rule amendments are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, EPA has determined that the final rule amendments contain no regulatory requirements that might significantly or uniquely affect small governments because they contain no requirements that apply to such governments or

impose obligations upon them. Therefore, today's action is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

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

Today's action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to today's action.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

Today's action does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. We do not know of any stationary gas turbines owned or operated by Indian tribal governments. However, if there are any, the effect of the final rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to today's action.

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

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

We interpret Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. Today's action is not subject to Executive Order 13045 because it is based on technology performance and not on health or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

Today's action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

Today's action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. Section 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing the final rule amendments and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final rule amendments in the **Federal Register**. Today's action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 25, 2006.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Reporting and recordkeeping requirements.

Dated: January 20, 2006.

Stephen L. Johnson,

Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of Federal Regulations is amended to read as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, *et seq.*

Subpart GG—[Amended]

■ 2. Section 60.334 is amended by:
■ a. Revising paragraphs (c) and (e);
■ b. Revising paragraph (f) introductory text and (f)(2); and
■ c. Revising paragraph (j) introductory text, (j)(1)(iv), and (j)(5) to read as follows:

§ 60.334 Monitoring of operations.

* * * * *

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_X emission limit under § 60.332, that approved procedure may continue to be used.

* * * * *

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions, may, but is not required to, elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in

paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_X emissions may, but is not required to, perform continuous parameter monitoring as follows:

* * * * *

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

* * * * *

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) * * *

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

* * * * *

(5) All reports required under § 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

■ 3. Section 60.335 is amended by revising paragraph (b)(8) to read as follows:

§ 60.335 Test methods and procedures.

* * * * *

(b) * * *

(8) If the owner or operator elects under § 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.334(g).

* * * * *

[FR Doc. 06–1743 Filed 2–23–06; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Parts 405, 410, 411, 413, 414, 424 and 426

[CMS–1502–F2 and CMS–1325–F]

RIN 0938–AN84 and 098–AN58

Medicare Program; Revisions to Payment Policies Under the Physician Fee Schedule for Calendar Year 2006 and Certain Provisions Related to the Competitive Acquisition Program of Outpatient Drugs and Biologicals Under Part B; Correcting Amendment

AGENCY: Centers for Medicare & Medicaid Services (CMS), HHS.

ACTION: Correcting amendment to final rule with comment.

SUMMARY: In the November 21, 2005 **Federal Register** (70 FR 70116), we published a final rule with comment period entitled "Medicare Program; Revisions to Payment Policies Under the Physician Fee Schedule for Calendar Year 2006 and Certain Provisions Related to the Competitive Acquisition Program of Outpatient Drugs and Biologicals Under Part B." This correcting amendment corrects technical errors in the November 21, 2005 publication.

EFFECTIVE DATE: This correcting amendment is effective January 1, 2006.

FOR FURTHER INFORMATION CONTACT: Diane Milstead, (410) 786–3355.

SUPPLEMENTARY INFORMATION:

I. Background

FR Doc. 05–22160, entitled "Medicare Program; Revisions to Payment Policies Under the Physician Fee Schedule for Calendar Year 2006 and Certain Provisions Related to the Competitive Acquisition Program of Outpatient Drugs and Biologicals Under Part B" and appearing in the **Federal Register** on November 21, 2005 (70 FR 70116), addressed Medicare Part B payment policy, including the physician fee schedule, that is applicable for calendar year (CY) 2006; and finalized certain provisions of the interim final rule to implement the Competitive Acquisition Program (CAP) for Part B Drugs.

It also revised Medicare Part B payment and related policies regarding: Physician work, practice expense and malpractice relative value units (RVUs); Medicare telehealth services; multiple diagnostic imaging procedures; covered outpatient drugs and biologicals; supplemental payments to Federally Qualified Health Centers (FQHCs); renal dialysis services; coverage for glaucoma screening services; National Coverage Decision (NCD) timeframes; and physician referrals for nuclear medicine services and supplies to health care entities with which physicians have financial relationships.

In addition, the rule finalized the interim RVUs for CY 2005 and issued interim RVUs for new and revised procedure codes for CY 2006. This rule also updated the codes subject to the physician self-referral prohibition and discussed payment policies relating to teaching anesthesia services, therapy caps, private contracts and opt-out, and chiropractic and oncology demonstrations.

We have identified a number of technical errors in that final rule with comment period.

II. Summary of Errors

We are identifying and correcting errors made to certain parts of the preamble, regulations text and addenda of the November 21, 2005 final rule with comment (70 FR 70116). In addition, addendum B, C, D, E and F are revised under this correcting amendment, although these addenda will not appear in the Code of Federal Regulations.

A. Summary of Preamble Errors

In the preamble text, there were a number of errors and omissions beginning on pages 70150 through 70335.

1. On page 70150, in the first column, in the last paragraph under Section m. (Additional PE Issues Raised by Commenters), in the second sentence, the number of the CPT code referenced is incorrect.

2. On page 70155, in the center column, the last sentence of the second paragraph under the discussion titled, "3. Cardiac Catheritization and Angioplasty Exception," there was an error in one of the code ranges referenced.

3. On page 70263, in the third column; in last paragraph, the reference to Table 26 is incorrect.

4. On page 70263, Table 26 was numbered incorrectly.

5. On page 70274, in the first column; in the second paragraph language concerning the specific deleted practice

technical standards (e.g., specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

Environment

The Coast Guard analyzed this rule under Commandant Instruction M16475.1D, which guides the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded that there are no factors in this case that would limit the use of a categorical exclusion under section 2.B.2 of the Instruction. Therefore, this rule is categorically excluded, under figure 2–1, paragraph (34)(g) from further environmental documentation. This rule fits the category selected from paragraph (34)(g), as it establishes a safety zone. An Environmental Analysis Checklist and Categorical Exclusion Determination are available for review at the location listed under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

■ For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1226 and 1231; 46 U.S.C. Chapter 701; 50 U.S.C. 191, 195; 33 CFR 1.05–1(g), 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. From 6 a.m. on November 29, 2005 until 11:59 p.m. on May 31, 2006, add temporary § 165.T01–106 to read as follows:

§ 165.T01–106 Regulated Navigation Area, East Rockaway Inlet to Atlantic Beach Bridge, Nassau County, Long Island, New York.

(a) *Location.* The following area is established as a Regulated Navigation Area: All waters of East Rockaway Inlet in an area bounded by lines drawn from the approximate position of the Silver Point breakwater buoy (LLN 31500) at 40°34′56″ N, 073°45′19″ W, running north to a point of land on the northwest side of the inlet at position 40°35′28″ N, 073°46′12″ W, thence easterly along the shore to the east side of the Atlantic Beach Bridge, State Route 878, over East Rockaway Inlet, thence across the bridge to the south side of East Rockaway Inlet, thence westerly along the shore and across the water to the beginning.

(b) *Regulations.* (1) Vessels carrying petroleum products as cargo, with a loaded draft greater than five feet, are prohibited from transiting within the regulated navigation area.

(2) Operators of vessels carrying petroleum products as cargo with a loaded draft greater than five feet must submit a request to transit the regulated navigation area to the Captain of the Port, Long Island Sound, at least 48 hours prior to transiting the area. Requests to transit the area shall consist of a general voyage plan identifying parameters for transit, to include the following: Weather conditions for transit, restrictions due to state of tide, the loaded draft of the vessel, and minimum acceptable under keel clearance. Once approved, vessels may transit the area in accordance with the approved voyage plan. Any modification or deviation from approved voyage plans must be submitted to the Captain of the Port, Long Island Sound at least 24 hours prior to the transit to which the modification applies.

(c) *Effective period.* This rule is effective from 6 a.m. on November 29, 2005 until 11:59 p.m. on May 31, 2006.

Dated: November 28, 2005.

David P. Pekoske,

Rear Admiral, U.S. Coast Guard, Commander, First Coast Guard District.

[FR Doc. 05–24135 Filed 12–15–05; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

Standards of Performance for New Stationary Sources

CFR Correction

In title 40 of the Code of Federal Regulations, Part 60 (§ 60.1 to End), revised as of July 1, 2005, on page 167, in § 60.41c, correct the definition of "Annual capacity factor" to read as follows:

§ 60.41c Definitions.

* * * * *

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

* * * * *

[FR Doc. 05–55521 Filed 12–15–05; 8:45 am]

BILLING CODE 1505–01–D

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2005–0234; FRL–7753–4]

Acetic acid, [(5-chloro-8-quinolinyl) oxy]-, 1-methylhexyl ester (Cloquintocet-mexyl); Pesticide Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is granting in part, and denying in part, pesticide petition PP 4E6831 submitted by Syngenta Crop Protection, Inc. that requested certain amendments to 40 CFR 180.560 for acetic acid [(5-chloro-8-quinolinyl) oxy]-, 1-methylhexyl ester; cloquintocet-mexyl; CAS Reg. No. 99607–70–2] and its acid metabolite (5-chloro-8-quinolinoxyacetic acid). EPA issued a notice pursuant to section 408(d)(3) of FFDCA, 21 U.S.C. 346a(d)(3) in the **Federal Register** of June 2, 2004 (69 FR 31116) (FRL–7357–8) announcing the filing of this petition requesting that the tolerance expressions under § 180.560 for wheat forage and hay be increased, the addition of tolerances for barley commodities (grain, hay, and straw), and the inclusion of a reference to the active ingredient pinoxaden. Although EPA finds it is safe to add a reference to pinoxaden and tolerances for barley (grain, hay, and straw) to this tolerance regulation, EPA does not agree that grounds exist to increase the tolerance expressions for wheat forage and hay. Thus, EPA is granting Syngenta's petition in as far as it seeks to add the reference pinoxaden and tolerances for barley (grain, hay, and straw) but is denying the request to increase the tolerance expressions for wheat forage and hay.

excluded, under figure 2–1, paragraph (34)(g), of the Instruction, from further environmental documentation. This event establishes a safety zone; therefore, paragraph (34)(g) of the Instruction applies.

A preliminary "Environmental Analysis Check List" is available in the docket where indicated under **ADDRESSES.** Comments on this section will be considered before we make the final decision on whether the rule should be categorically excluded from further environmental review.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

■ For the reasons discussed in the preamble, the Coast Guard amends 33 CFR Part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1226, 1231; 46 U.S.C. Chapter 701; 50 U.S.C. 191, 195; 33 CFR 1.05–1(g), 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. A new temporary § 165.T09–108 is added to read as follows:

§ 165.T09–108 Safety Zone; NY.

(a) *Location.* The following area is a temporary safety zone: all waters of the Niagara River within an 800 foot radius of the fireworks barge moored/anchored in approximate position 43°09′27″ N, 076°20′25″ W (NAD 83).

(b) *Effective time and date.* This section is effective from 10 p.m. (local) until 10:30 p.m. (local) on September 17, 2005.

(c) *Regulations.* In accordance with the general regulations in § 165.23 of this part, entry into this safety zone is prohibited unless authorized by the Coast Guard Captain of the Port Buffalo, or his designated on-scene representative.

Dated: August 4, 2005.

S.J. Ferguson,

Captain, U.S. Coast Guard, Captain of the Port Buffalo.

[FR Doc. 05–17159 Filed 8–29–05; 8:45 am]

BILLING CODE 4910–15–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[MN–86–2; FRL–7962–6]

Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Revised Format of 40 CFR Part 52 for Materials Being Incorporated by Reference; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correcting amendment.

SUMMARY: This document corrects an error in the amendatory instruction in a final rule pertaining to the Revised Format of 40 CFR part 52 for Materials Being Incorporated by Reference for Minnesota.

DATES: This final rule is effective on August 30, 2005.

FOR FURTHER INFORMATION CONTACT: Christos Panos, Environmental Engineer, Criteria Pollutant Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, Region 5, Chicago, Illinois 60604, (312) 353–8328, or by e-mail at *panos.christos@epa.gov.*

SUPPLEMENTARY INFORMATION: EPA published a document on February 24, 2005 (70 FR 8930) redesignating § 52.1220 as § 52.1222, when § 52.1222 already existed. The intent of the rule was to remove the then existing § 52.1222 titled "EPA-approved Minnesota State regulations" and then redesignate § 52.1220 as § 52.1222. This document corrects the erroneous amendatory language.

Correction

In the final rule published in the **Federal Register** on February 24, 2005 (70 FR 8930), on page 8932 the amendatory instruction is corrected. Section 553 of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making today's rule final without prior proposal and opportunity for comment because we are merely correcting an incorrect citation in a previous action. Thus, notice and public procedure are unnecessary. We find that this constitutes good cause under 5 U.S.C. 553(b)(B).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: August 8, 2005.

Norman Niedergang,

Acting Regional Administrator, Region 5.

■ Part 52 of chapter I, title 40, Code of Federal Regulations, is amended as follows:

PART 52—[AMENDED]

■ 1. The authority for citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart Y—Minnesota

§ 52.1222 [Removed]

■ 2. Section 52.1222 titled "EPA-approved Minnesota State regulations" is removed.

§ 52.1220 [Redesignated as § 52.1222]

■ 3. Section 52.1220 is redesignated as § 52.1222 and the section heading and paragraph (a) are revised to read as follows:

§ 52.1222 Original identification of plan section.

(a) This section identifies the original "Air Implementation Plan for the State of Minnesota" and all revisions submitted by Minnesota that were federally approved prior to December 1, 2004.

* * * * *

[FR Doc. 05–17203 Filed 8–29–05; 8:45 am]

BILLING CODE 6560–50–U

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 75

[OAR–2002–0056; FRL–7960–1]

RIN 2060–AJ65

Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; corrections.

SUMMARY: This action corrects and clarifies certain text of the final rule entitled "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating

Units." The final rule was published in the Federal Register on May 18, 2005 (70 FR 28606).

This action corrects certain section designations set forth in the final rule at 70 FR 28652. In addition, this action corrects certain revisions set forth in the final rule at 70 FR 28678. These corrections do not affect the substance of the action, nor do they change the rights or obligations of any party. Rather, this action merely corrects certain section designations to eliminate duplication with other rules. Thus, it is proper to issue these final rule corrections without notice and comment. Section 553 of the Administrative Procedure Act (APA), 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. We have determined that there is good cause for making this action final without prior proposal and opportunity for comment because the changes to the rule are minor technical corrections, are noncontroversial, and do not substantively change the agency actions taken in the final rule. Thus, notice and public procedure are unnecessary. We find that this constitutes good cause under 5 U.S.C. 553(b)(B).

EFFECTIVE DATE: May 18, 2005.

FOR FURTHER INFORMATION CONTACT: Mr. William Maxwell, Combustion Group, Emission Standards Division (C439–01), EPA, Research Triangle Park, North Carolina, 27711; telephone number (919) 541–5430; fax number (919) 541–5450; electronic mail address: *maxwell.bill@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. What Is the Background for the Corrections?

On May 18, 2005 (70 FR 28606), EPA issued a final rule in which EPA promulgated new source performance standards for new coal-fired electric utility steam generating units and emission guidelines for existing coal-fired electric utility steam generating units designed to limit mercury (Hg) emissions from such sources. EPA subsequently determined that certain sections of the final rule were not properly designated, *i.e.*, the numbering was not correct, and that certain rule text was not properly identified as introductory text. This action corrects those technical errors.

II. What Are the Corrections to Final Rule (70 FR 28652, 27678)?

This notice corrects the following errors. In inserting a section to 40 CFR part 60, subpart Da (*e.g.*, 40 CFR 60.45a), to incorporate emission limitations for Hg, subsequent sections were renumbered. In so doing, we inadvertently assigned section numbers to 40 CFR part 60, subpart Da, that were already in use in 40 CFR part 60, subpart Ea. To correct this error, it is necessary to renumber all of the sections in 40 CFR part 60, subpart Da, and to correct the associated internal references in the same manner. Further, in revising 40 CFR 75.6, we inadvertently indicated that we were revising entire paragraphs, rather than just the introductory text.

III. Statutory and Executive Order Reviews

Under Executive Order 12866, Regulatory Planning and Review (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is, therefore, not subject to review by the Office of Management and Budget (OMB). This action is not a "major rule" as defined by 5 U.S.C. 804(2). The technical corrections do not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). Because EPA has made a "good cause" finding that this action is not subject to notice and comment requirements under the APA or any other statute, it is not subject to the regulatory flexibility provisions of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), or to sections 202 and 205 of the Unfunded Mandates Reform Act of 1995 (UMRA) (Pub. L. 104B4). In addition, this action does not significantly or uniquely affect small governments or impose a significant intergovernmental mandate, as described in sections 203 and 204 of the UMRA.

The corrections do not have substantial direct effects on the States, or on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, Federalism (64 FR 43255, August 10, 1999).

Today's action also does not significantly or uniquely affect the communities of Tribal governments, as specified in Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (65 FR 67249, November 9, 2000). The technical corrections also are not subject to Executive Order 13045, Protection of Children from Environmental Health and Safety Risks (62 FR 19885, April 23, 1997) because this action is not economically significant.

The corrections are not subject to Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (66 FR 28355, May 22, 2001) because this action is not a significant regulatory action under Executive Order 12866.

The corrections do not involve changes to the technical standards related to test methods or monitoring methods; thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply.

The corrections also do not involve special consideration of environmental justice-related issues as required by Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (59 FR 7629, February 16, 1994).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. EPA will submit a report containing today's final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of today's action in the **Federal Register**. Today's action is not a "major rule" as defined by 5 U.S.C. 804(2). The final rule will be effective on May 18, 2005.

EPA's compliance with the above statutes and EO for the underlying rule is discussed in the May 18, 2005 **Federal Register** notice containing "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" (70 FR 28606).

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Coal, Electric power plants, Incorporation by reference, Intergovernmental relations, Metals, Natural gas, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 75

Acid rain, Air pollution control, Carbon dioxide, Electric utilities, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: August 19, 2005.

Jeffrey R. Holmstead,

Assistant Administrator, Office of Air and Radiation.

■ For the reasons stated in the preamble, title 40, chapter I of the Code of the Federal Regulations is amended as follows:

PART 60—[AMENDED]

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

Authority: 42 U.S.C. 7401, 7403, 7426, and 7601.

Subpart Da—[AMENDED]

■ 2. Subpart Da is amended as follows:
■ a. Redesignating § 60.40a as § 60.40Da;
■ b. Redesignating § 60.41a as § 60.41Da;
■ c. Redesignating § 60.42a as § 60.42Da;
■ d. Redesignating § 60.43a as § 60.43Da;
■ e. Redesignating § 60.44a as § 60.44Da;
■ f. Redesignating § 60.45a as § 60.45Da;
■ g. Redesignating § 60.46a as § 60.46Da;
■ h. Redesignating § 60.47a as § 60.47Da;
■ i. Redesignating § 60.48a as § 60.48Da;
■ j. Redesignating § 60.49a as § 60.49Da;
■ k. Redesignating § 60.50a as § 60.50Da;
■ l. Redesignating § 60.51a as § 60.51Da; and
■ m. Redesignating § 60.52a as § 60.52Da.

§ 60.43Da [Amended]

■ 3. Newly redesignated § 60.43Da is amended by revising the existing reference in paragraph (f) from "§ 60.45a" to "§ 60.47Da".

§ 60.44Da [Amended]

■ 4. Newly redesignated § 60.44Da is amended as follows:
■ a. Revising the existing reference in paragraph (a) from "§ 60.46a(j)(1)" to "§ 60.48Da(j)(1)";
■ b. Revising the existing reference in paragraph (b) from "§ 60.45a" to "§ 60.47Da"; and
■ c. Revising the existing reference in paragraph (d)(1) from "§ 60.46a(k)(1)" to "§ 60.48Da(k)(1)".

§ 60.45Da [Amended]

■ 5. Newly redesignated § 60.45Da is amended by:
■ a. Revising the existing reference in paragraph (a) from "§ 60.50a(h)" to "§ 60.50Da(h)"; and
■ b. Revising the existing reference in paragraph (b) from "§60.50a(g)" to "§60.50Da(g)".

§ 60.47Da [Amended]

■ 6. Newly redesignated § 60.47Da is amended as follows:
■ a. Revising the existing reference in paragraph (b) from "§ 60.43a(c)" to "§ 60.43Da(c)";
■ b. Revising the existing reference in paragraph (c) from "§ 60.43a(a)" to "§ 60.43Da(a)"; and
■ c. Revising the existing reference in paragraph (d) from "§ 60.44a(a)" to "§ 60.44Da(a)".

§ 60.48Da [Amended]

■ 7. Newly redesignated § 60.48Da is amended as follows:
■ a. Revising the existing references in paragraph (a) from "§ 60.42a(a)(1)" to "§ 60.42Da(a)(1)" and from "§ 60.42a(a)(2) and (3)" to "§ 60.42Da(a)(2) and (3)";
■ b. Revising the existing references in paragraph (b) from "§ 60.44a(a)" to "§ 60.44Da(a)" and from "§ 60.44a(a)(2)" to "§ 60.44Da(a)(2)";
■ c. Revising the existing references in paragraph (c) from "§ 60.42a" to "§ 60.42Da", from "§ 60.44a" to "§ 60.44Da", and from "§ 60.45a" to "§ 60.45Da";
■ d. Revising the existing reference in paragraph (d)(3) from "§ 60.43a" to "§ 60.43Da";
■ e. Revising the existing references in paragraph (e) from "§ 60.43a" to "§ 60.43Da" and from "§ 60.44a" to "§ 60.44Da";
■ f. Revising the existing references in paragraph (f) from "§ 60.43a" to "§ 60.43Da" and from "§ 60.44a" to "§ 60.44Da";
■ g. Revising the existing references in paragraph (h) from "§ 60.49a" to "§ 60.49Da", from "§ 60.43a" to "§ 60.43Da", and from "60.44a" to "§ 60.44Da";
■ h. Revising the existing references in paragraph (i) from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)", from "§ 60.49a(c)" to "§ 60.49Da(c)", from "§ 60.49a(l)" to "§ 60.49Da(l)", and from "§ 60.49a(k)" to "§ 60.49Da(k)";
■ i. Revising the existing reference in paragraph (j) introductory text from "§ 60.44a(a)(1)" to "§ 60.44Da(a)(1)";
■ j. Revising the existing reference in paragraph (j)(1) from "§ 60.44a(a)(1)" to "§ 60.44Da(a)(1)";
■ k. Revising the existing references in paragraph (j)(2) from "§ 60.49a" to "§ 60.49Da";
■ l. Revising the existing references in paragraph (k) introductory text from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ m. Revising the existing reference in paragraph (k)(1) from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ n. Revising the existing reference in paragraph (k)(1)(iv) from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ o. Revising the existing reference in paragraph (k)(2) introductory text from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ p. Revising the existing references in paragraph (k)(2)(ii) from "§ 60.49a" to "§ 60.49Da" and from "§ 60.49a(l)" to "§ 60.49Da(l)";
■ q. Revising the existing reference in paragraph (k)(2)(iii) from "§ 60.49a(k)" to "§ 60.49Da(k)";
■ r. Revising the existing reference in paragraph (k)(2)(iv) from "§ 60.49a(l)" to "§ 60.49Da(l)"; and
■ s. Revising the existing references in paragraph (l) from "§ 60.45a" to "§ 60.45Da", from "§ 60.49a(p)" to "§ 60.49Da(p)", from "§ 60.49a(l) or (m)" to "§ 60.49Da(l) or (m)", and from "§ 60.49a(k)" to "§ 60.49Da(k)".

§ 60.49Da [Amended]

■ 8. Newly redesignated § 60.49Da is amended as follows:
■ a. Revising the existing reference in paragraph (b)(2) from "§ 60.43a(d)" to "§ 60.43Da(d)";
■ b. Revising the existing references in paragraph (c)(2) from "§ 60.51a" to "§ 60.51Da";
■ c. Revising the existing reference in paragraph (g) from "§ 60.48a" to "§ 60.48Da";
■ d. Revising the existing reference in paragraph (k) from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ e. Revising the existing reference in paragraph (l) from "§ 60.44a(d)(1)" to "§ 60.44Da(d)(1)";
■ f. Revising the existing references in paragraph (o) from "§ 60.41a" to "§ 60.41Da" and from "§ 60.44a(a)(1) or (d)(1)" to "§ 60.44Da(a)(1) or (d)(1)";
■ g. Revising the existing reference in paragraph (p) from "§ 60.45a" to "§ 60.45Da";
■ h. Revising the existing reference in paragraph (p)(4)(iii) from "§ 60.49a(p)(4)(i)" to "§ 60.49Da(p)(4)(i)"; and
■ i. Revising the existing reference in paragraph (p)(4)(iv) from "§ 60.49a(p)(4)(i)" to "§ 60.49Da(p)(4)(i)".

§ 60.50Da [Amended]

■ 9. Newly redesignated § 60.50Da is amended as follows:
■ a. Revising the existing reference in paragraph (b) introductory text from "§ 60.42a" to "§ 60.42Da";
■ b. Revising the existing reference in paragraph (c) introductory text from "§ 60.43a" to "§ 60.43Da";

■ c. Revising the existing reference in paragraph (c)(5) from "§ 60.49a(b) and (d)" to "§ 60.49Da(b) and (d)";
■ d. Revising the existing reference in paragraph (d) introductory text from "§ 60.44a" to "§ 60.44Da";
■ e. Revising the existing reference in paragraph (d)(2) from "§ 60.49a(c) and (d)" to "§ 60.49Da(c) and (d)";
■ f. Revising the existing reference in paragraph (e)(2) from "§ 60.48a(d)(1)" to "§ 60.48Da(d)(1)";
■ g. Revising the existing references in paragraph (g) introductory text from "§ 60.45a" to "§ 60.45Da" and from "§ 60.46a" to "§ 60.46Da";
■ h. Revising the existing reference in paragraph (h) introductory text from "§ 60.45a" to "§ 60.45Da"; and
■ i. Revising the existing reference in paragraph (h)(1) from "§ 60.49a(p)(4)(i)" to "§ 60.49Da(p)(4)(i)".

§ 60.51Da [Amended]

■ 10. Newly redesignated § 60.51Da is amended as follows:
■ a. Revising the existing references in paragraph (c) introductory text from "§ 60.49a" to "§ 60.49Da" and from "§ 60.48a(h)" to "§ 60.48Da(h)";
■ b. Revising the existing reference in paragraph (d) introductory text from "§ 60.43a" to "§ 60.43Da";
■ c. Revising the existing reference in paragraph (d)(1) from "§ 60.48a(d)" to "§ 60.48Da(d)";
■ d. Revising the existing reference in paragraph (e) introductory text from "§ 60.43a" to "§ 60.43Da";
■ e. Revising the existing reference in paragraph (e)(1) from "§ 60.50a" to "§ 60.50Da"; and
■ f. Revising the existing reference in paragraph (i) from "§ 60.42a(b)" to "§ 60.42Da(b)".

§ 60.52Da [Amended]

■ 11. Newly redesignated § 60.52Da is amended by revising the existing references from "§ 60.45a" to "§ 60.45Da" and from "§ 60.46a" to "§ 60.46Da".

PART 75—[AMENDED]

■ 12. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601, 7651k, and 7651k.

■ 13. Section 75.6 is amended by revising paragraphs (b) introductory text, (c), (d) introductory text, and (e) introductory text to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, New Jersey 07007–2900:

* * * * *

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987(E) Measurement of Liquid Flow in closed Conduits-Method by Collection of the Liquid in a Volumetric Tank, for appendices D and E of this part.

(2) [Reserved].

* * * * *

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

* * * * *

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

* * * * *

[FR Doc. 05–16927 Filed 8–29–05; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2003–0121; AD–FRL–7961–9]

RIN 2060–AN09

National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Partial withdrawal of direct final rule.

SUMMARY: On July 1, 2005, the EPA issued direct final amendments to the national emission standards for hazardous air pollutants (NESHAP) for Miscellaneous Organic Chemical Manufacturing, along with a parallel proposal to be used as the basis for final action in the event EPA received any adverse comments on the direct final amendments. Because adverse comment was received, EPA is withdrawing the corresponding parts of the direct final rule. We stated in that direct final rule that if we received adverse comment by August 1, 2005, we would publish a timely withdrawal in the **Federal Register**. We will address all comments in a subsequent final rule based on the parallel proposal published on July 1, 2005. As stated in the parallel proposal, we will not institute a second comment period on this action.

DATES: As of August 30, 2005, EPA withdraws the direct final rule amendments to 40 CFR 63.2485(c)(4) and Table 1 to subpart FFFF of part 63, published on July 1, 2005 (70 FR 38554). The remaining provisions published on July 1, 2005, will be effective on August 30, 2005.

ADDRESSES: EPA has established a docket for this action under Docket ID No. OAR–2003–0121. All documents in the docket are listed in the index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at: Air and Radiation Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Randy McDonald, Organic Chemicals Group, Emission Standards Division (Mail Code C504–04), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone number (919) 541–5402, electronic mail address *mcdonald.randy@epa.gov.*

SUPPLEMENTARY INFORMATION: On July 1, 2005, we published a direct final rule (70 FR 38554) and a parallel proposal (70 FR 38562) amending the NESHAP for Miscellaneous Organic Chemical Manufacturing (40 CFR part 63, subpart FFFF). We amended the NESHAP by: Clarifying the compliance requirements for flares and the alternative standard, extending the vapor balancing alternative to cover transfers from barges to storage tanks, amending the procedures for correcting measured concentrations at the outlet of combustion devices to correct for dilution by supplemental gas, and clarifying the signature requirements for the notification of compliance status report. The direct final rule amendments also specified requirements for effluent from control devices, clarified the definition of the term continuous process vent, and

NOTICE OF PUBLIC HEARING AND PUBLIC COMMENT PERIOD

On Monday, July 9, 2007 beginning at 6 p.m., the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ) will hold a public hearing on proposed revisions to existing legislative rules. Oral and written comments shall be limited only to the proposed revisions to the following existing legislative rules:

45CSR6	To Prevent and Control Air Pollution From Combustion of Refuse;
45CSR8	Ambient Air Quality Standards for Sulfur Oxides and Particulate Matter;
45CSR16	Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60;
45CSR18	To Prevent and Control Emissions From Commercial and Industrial Solid Waste Incineration Units;
45CSR25	To Prevent and Control Air Pollution from Hazardous Waste Treatment, Storage, or Disposal Facilities;
45CSR34	Emission Standards for Hazardous Air Pollutants for Source Categories Pursuant to 40 CFR Part 63;
45CSR39	Control of Annual Nitrogen Oxide Emissions to Mitigate Interstate Transport of Fine Particulate Matter and Nitrogen Oxides;
45CSR40	Control of Ozone Season Nitrogen Oxide Emissions to Mitigate Interstate Transport of Ozone and Nitrogen Oxides; and
45CSR41	Control of Annual Sulfur Dioxide Emissions to Mitigate Interstate Transport of Fine Particulate Matter and Sulfur Dioxide.

On Monday, July 9, 2007, after public hearings on the above proposed legislative rules, the West Virginia Department of Environmental Protection, DAQ will hold a public hearing on the following proposed legislative rule:

45CSR42	Greenhouse Gas Emissions Inventory Program.

Upon authorization and promulgation of revisions to 45CSR6, 45CSR8, 45CSR39, 45CSR40 and 45CSR41, the DAQ will submit the final rules to the U.S. Environmental Protection Agency (U.S. EPA) as revisions to the State Implementation Plan, pursuant to the federal Clean Air Act.

Upon authorization and promulgation of revisions to 45CSR16, the DAQ will submit the final rule to the U.S. EPA for approval as a part of West Virginia's program delegation of the federal New Source Performance Standards.

Upon authorization and promulgation of revisions to 45CSR18, the DAQ will submit the final rule to the U.S. EPA for approval as a part of West Virginia's Section 111(d)/129 Plan and program delegation of the federal New Source Performance Standards.

Upon authorization and promulgation of revisions to 45CSR25, the DAQ will submit the final rule to the U.S. EPA for approval as part of the West Virginia Hazardous Waste Management Program.

Upon authorization and promulgation of revisions to 45CSR34, the DAQ will submit the final rule to the U.S. EPA for approval as a part of West Virginia's program delegation of the National Emission Standards for Hazardous Air Pollutants.

Upon authorization and promulgation of 45CSR42, the DAQ will begin implementation of a Greenhouse Gas Inventory Program.

The public hearing will be held at the Department of Environmental Protection, Dolly Sods Conference Room, 601 57th Street SE, Charleston and is open to the public. Written and oral comments will be accepted until the close of the hearing and will be made a part of the rulemaking record. Comments will also be accepted by fax (304-926-0479), U.S. Mail, or e-mail if postmarked or delivered by the close of business on July 9, 2007.

Copies of the proposed legislative rules may be viewed between 8:30 a.m. and 4:30 p.m. at the Division of Air Quality, 601 57th SE, Charleston, WV 25304 beginning June 8, 2007 or electronically upon e-mail request to: tmowrer@wvdep.org. For a copy of the proposed rules, access the following web address: www.wvdep.org/daq. Choose Public Notice and Comment.

Send written comments to John A. Benedict, Director, Division of Air Quality at the above address. Please identify the draft document to which the comments apply, the commenter's name, address, and telephone number. Comments will also be accepted by e-mail if transmitted by 5:00 p.m. on July 9, 2007 to: tmowrer@wvdep.org. Comments submitted by U.S. Mail must be postmarked by July 9, 2007.

CHARLESTON NEWSPAPERS
P O Box 2993
Charleston, West Virginia 25330
Billing 348-4898
Classified 348-4848
1 800-WVA-NEWS

LEGAL ADVERTISING

INVOICE DATE	06/11/07
ACCOUNT NBR	034320005
SALES REP ID	0020
INVOICE NBR	421127001

M

BILLED TO

WV DIV ENVIRONMENTAL PROTECT
OFFICE OF AIR QUALITY
601 57TH STREET
CHARLESTON WV 25304 USA

06-13-07F01:42 RCVD

Please return this portion with your payment. AMOUNT PAID: _____

Make checks payable to: Charleston Newspapers

CHARLESTON NEWSPAPERS
P.O. Box 2993
Charleston, West Virginia 25330
Billing 348-4898
Classified 348-4848
1-800-WVA-NEWS
FEIN 55-0676079

INVOICE DATE	06/11/07
ACCOUNT NBR	034320005
SALES REP ID	0020
INVOICE NBR	421127001

Legal pricing is based upon 63 words per column inch
Each successive insertion is discounted by 25% of the first insertion rate
The Daily Mail is at a rate of $.14 per word, and the Charleston Gazette is at a rate of $.14 per word.

ISSUE DATE	AD TYPE	PUB	DESCRIPTION / REFERENCE NBR / PURCHASE ORDER #	AD NUMBER	AD SIZE / TOTAL RUN	RATE	GROSS AMOUNT	NET AMOUNT
06/08	LEG	DM	Public Notice - Legi 421127001 Jessica Gr	0287864	2X1125 22.50	8.82	198.45	198.45
06/08	LEG	GZ	Public Notice - Legi 421127002 Jessica Gr		2X1125 22.50	8.82	198.45	198.45
			TOTAL INVOICE AMOUNT					396.90

State of West Virginia **AFFIDAVIT OF PUBLICATION**

I, Amora Riggs of
THE CHARLESTON GAZETTE, A DAILY DEMOCRATIC NEWSPAPER
THE DAILY MAIL, A DAILY REPUBLICAN NEWSPAPER,
published in the city of Charleston, Kanawha County, West Virginia, do solemnly swear that the annexed notice of:
Public Notice - Legislat
was duly published in said paper(s) during the dates listed below, and was posted at the front door of the court house of said Kanawha County.
West Virginia, on the 9TH day of JUNE 2007 Published during the following dates: 06/08/07-06/08/07
Subscribed and sworn to before me this 12 day of June
Printers fee $ 396.90

Notary Public

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
LYNN B. FIELDER
25[illegible] FRAZIER [illegible]
SCOTT DEPOT, WV 25560
My commission expires [illegible] 11, 2015

Division of Mining and Reclamation

38CSR2 - Surface Mining Reclamation Rule. The public hearing will be held at 5 p.m. on July 10, 2007, in the Canaan Valley Room. The comment period will end at the conclusion of the hearing.

47CSR5A - Individual State Certification of Activities Requiring a Federal Permit. The public hearing will be held at 6 p.m. on July 10, 2007, in the Canaan Valley Room. The comment period will end at the conclusion of the hearing.

47CSR30 - WV/NPDES Rules for Coal Mining Facilities. The public hearing will be held at 6 p.m. on July 10, 2007, in the Canaan Valley Room. The comment period will end at the conclusion of the hearing.

19CSR1 - Surface Mining Blasting Rule. The public hearing will be held at 5 p.m. on July 10, 2007, in the Canaan Valley Room. The comment period will end at the conclusion of the hearing.

For more information on any of the DWWM rules, call 926-0490.

Office of Oil and Gas

35CSR3 - Coalbed Methane Wells Rule. The public hearing will be held at 6 p.m. on July 17, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing. For more information, call 926-0450.

Division of Land Restoration

33CSR10 - Recycling Assistance Grant Program. The public hearing will be held at 6 p.m. on July 12, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

40CSR3 - Voluntary Remediation and Redevelopment Rule. The public hearing will be held at 6:30 p.m. on July 12, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

For more information on any of the DLR rules, call 926-0455.

Public Information Office

60CSR8 - Environmental Excellence Rule. The public hearing will be held at 7 p.m. on July 17, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing. For more information, call 926-0440.

(287864)

Division of Water and Waste Management

33CSR9 - Standards for Beneficial use of Filtrate from Water Treatment Plants. The public hearing will be held at 6 p.m. on July 2, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

33CSR20 - Hazardous Waste Management System. The public hearing will be held at 6 p.m. on July 11, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

33CSR30 - Underground Storage Tanks. The public hearing will be held at 6:30 p.m. on July 11, 2007, in the Coopers Rock Training Room at DEP's Charleston headquarters. The comment period will end at the conclusion of the hearing.

47CSR2 - Rules Governing Water Quality Standards. The public hearing will be held at 6 p.m. on July 16, 2007, in the Coopers Rock Training Room. The comment period will end at 5 p.m. on July 17, 2007. The rule includes a proposed use redesignation for Pat's Branch in the Guyandotte River Basin (see additional information in the information sheet attached to the briefing document).

47CSR10 - National Pollutant Discharge Elimination System (NPDES). The public hearing will be held at 6:30 p.m. on July 17, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

47CSR34 - Dam Safety. The public hearing will be held at 7 p.m. on July 11, 2007, in the Coopers Rock Training Room. The comment period will end at the conclusion of the hearing.

60CSR5 - Implementation - Antidegradation Procedures. The public hearing will be held at 7 p.m. on July 16, 2007, in the Coopers Rock Training Room. The comment period will end at 5:00 p.m. on July 17, 2007.

For more information on any of the DWWM rules, call 926-0495.

PUBLIC NOTICE

The West Virginia Department of Environmental Protection has scheduled public hearings for its 2008 proposed legislative rules. All hearings will be held at DEP's Charleston headquarters, 601 57th Street S.E., Charleston, WV 25304. Oral and written comments shall be limited to the proposed revisions to the following rules. All comments will be made a part of the rulemaking record. Copies of the rules and other rule documents are available from the Secretary of State's office or from the agency at www.wvdep.org/2008rules. You may also obtain hardcopies of the information by calling the phone numbers listed below. Written comments may be submitted to the Public Information Office at the above address. Comments may also be e-mailed to comments@wvdep.org. The hearing dates, locations and comment deadlines are as follows:

Division of Air Quality

45CSR6 - Control of Air Pollution from Combustion of Refuse

45CSR8 - Ambient Air Quality Standards

45CSR16 - Standards of Performance for New Stationary Sources

45CSR18 - Control of Air Pollution from Combustion of Solid Waste

45CSR25 - Control of Air Pollution from Hazardous Waste Treatment, Storage and Disposal Facilities

45CSR34 - Emission Standards for Hazardous Air Pollutants

45CSR39 - Control of Annual Nitrogen Oxides Emissions

45CSR40 - Control of Ozone Season Nitrogen Oxides Emissions

45CSR41 - Control of Annual Sulfur Dioxide Emissions

45CSR42 - Greenhouse Gas Emissions Inventory Program

The public hearing for all air quality rules will be held at 6 p.m. on July 9, 2007, in the Daily Soda conference room. The comment period will end at the conclusion of the hearing. Upon authorization and promulgation of revisions to 45CSR6, 45CSR8, 45CSR39, 45CSR40 and 45CSR41, the DAQ will submit the rules to the U.S. Environmental Protection Agency (EPA) as revisions to the State Implementation Plan pursuant to the federal Clean Air Act (CAA). Rules 45CSR16, 45CSR18, 45CSR25, and 45CSR34 will also be submitted to EPA to fulfill other federal obligations under the CAA, including delegations, plans and program approvals. For more information on any of the air rules, call 926-0475.

dep

west virginia department of environmental protection

DAQ 2008 Proposed Rules Hearing
Dolly Sods Conference Room
601 57th Street SE, Charleston
July 9, 2007 6:00 p.m.

Sign-In

NAME (Please Print)	ADDRESS	ORGANIZATION	PHONE/FAX	E-MAIL	COMMENT YES/NO
LINDA K TENNANT	300 KANAWHA BLVD	SPILMAN THOMAS	304.720.3420	ltennant@spilmanlaw.com	written
Tim Mallan	707 Va. Street E	Appalachian Power	304-348-4136	tpmallan@aep.com	No.
Anne Blankenship	700 Virginia St E	Robinson+McElwee	304-347-8334	acb@ramlaw.com	written only
Jon Mason	601 57th St	WVDEP	926 0499 ext 1209	jmason@wvdep.org	n/o

ORIGINAL

BEFORE THE WEST VIRGINIA DEPARTMENT OF
ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY

In the matter of: PROPOSED REVISIONS TO 45CSR16 - Standards of Performance for New Stationary Sources

Transcript of proceedings had at a public hearing in the above-styled matter taken by Missy L. Young, Certified Court Reporter, at the West Virginia Department of Environmental Protection, Division of Air Quality, Dolly Sods Conference Room, 601 57th Street, S.E. Charleston, West Virginia, commencing at 6:11 p.m., on the 9th day of July 2007, pursuant to notice.

MISSY L. YOUNG, C.C.R.
POST OFFICE BOX 13221
SISSONVILLE, WEST VIRGINIA 25360
(304) 984-2300

P R O C E E D I N G S

MS. CHANDLER: The purpose of this public hearing is to accept comments on the proposed revisions to 45CSR16 - Standards of Performance for New Stationary Sources.

The rule establishes and adopts national standards of performance for new stationary sources, NSPS is that acronym for that, and other regulatory requirements promulgated by the U.S. Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended.

This rule codifies general procedures and criteria to implement standards of performance for new stationary sources set forth in 40 CFR Part 60. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to such standards. Any person who constructs, modifies, reconstructs or operates an affected facility after the effective date of any NSPS under 40 CFR Part 60 must comply with the applicable NSPS and this rule.

This revised rule incorporates by reference the following new or revised NSPS standards promulgated as of June 1, 2007: Standards of Performance for: New and

Existing Stationary Sources - Electric Utility Steam Generating Units; Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, Industrial-Commercial-Institutional Steam Generating Units, Small Industrial-Commercial-Institutional Steam Generating Units; Stationary Gas Turbines and Monitoring Requirements; Stationary Compression Ignition Internal Combustion Engines; and Methods for Measurement of Visible Emissions.

Upon authorization and promulgation of revisions to 45CSR16, the Division of Air Quality will submit the final rules to the U.S. Environmental Protection Agency to fulfill other federal obligations under the Clean Air Act, including delegations, plans and program approval.

The floor is now open for comments. Please state4 your name and any affiliation.

There being nothing further, this public hearing for the proposed revisions to 45CSR16 is concluded.

(WHEREUPON, the hearing was concluded at 6:14 p.m.)

STATE OF WEST VIRGINIA,

COUNTY OF KANAWHA, to-wit:

I, the undersigned, Missy L. Young, a Certified Court Reporter and Commissioner within and for the State of West Virginia, duly commissioned and qualified, do hereby certify that the foregoing, is to the best of my skill and ability, a true and accurate transcript of all the proceedings had in the aforementioned matter.

Given under my hand and official seal this 20th day of July 2007.

Missy L. Young, CCR

Missy L. Young
Certified Court Reporter
Commissioner for the State of West Virginia

My commission expires April 15, 2008.

From: Paula Finck <paulafinck@yahoo.com>
To: <comments@wvdep.org>
Date: 6/27/2007 10:08:43 PM
Subject: Re: air quality rules

Now is the time to put into effects the toughest air quality rules for the sake of the present and future health of the citizens of these United States of America. It is your job and your responsibility to the people.

Respectfully yours,
Paula Finck

45CSR16

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

RESPONSE TO COMMENTS

On June 8, 2007, the Division of Air Quality (DAQ) commenced a thirty day public comment period and subsequently held a public hearing on July 9, 2007 to accept oral comments on proposed revision to legislative rule 45CSR16. Written comments were also accepted through 6:00 PM on Monday, July 9, 2007. No commenter submitted written comments regarding proposed revisions to rule 45CSR16, and no commenter provided verbal comments.