United States
Environmental Protection
Agency

Air Pollution Training Institute
MD 20
Environmental Research Center
Research Triangle Park NC 27711

EPA 450/2-84-001
April 1984

EPA

APTI Course 482 Sources and Control of Volatile Organic Air Pollutants

Regulatory Documents Updates and NSPS Regulations

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Regulatory Documents Updates and NSPS Regulations

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Under Contract No.
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United States Environmental Protection Agency
Manpower and Technical Information Branch
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Notice

This is not an official policy and standards document. The opinions and selections are those of the authors and not necessarily those of the Environmental Protection Agency. Every attempt has been made to represent the present state of the art as well as subject areas still under evaluation. Any mention of products or organizations does not constitute endorsement by the United States Environmental Protection Agency.

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I. SIP Requirements, Policy Statements, and Control Techniques Guidelines

federal register

Thursday
August 7, 1980

Part III

Environmental Protection Agency

Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, and 124

[FRL 1538-2]

Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans

AGENCY: Environmental Protection Agency.

ACTION: Final rules.

SUMMARY: In response to the decision of the U.S. Court of Appeals for the D.C. Circuit in *Alabama Power Company* v. *Costle*, EPA is today amending its regulations for the prevention of significant deterioration of air quality, 40 CFR 51.24, 52.21. Today's amendments also include regulatory changes affecting new source review in nonattainment areas, including restrictions on major source growth (40 CFR 52.24) and requirements under EPA's Emission Offset Interpretative Ruling (40 CFR Part 51, Appendix S) and Section 173 of the Clean Air Act (40 CFR 51.18 (j)).

DATES: The regulatory amendments announced here come into effect on August 7, 1980. State Implementation Plan revisions meeting today's regulatory changes are to be submitted to EPA within nine months after this publication.

FOR FURTHER INFORMATION CONTACT: James B. Weigold, Standards Implementation Branch (MD-15), Office of Air Quality Planning and Standards, Research Triangle Park, N.C. 27711, 919/541-5292.

SUPPLEMENTARY INFORMATION: The contents of today's preamble are listed in the following outline. A section entitled Summary of PSD Program has been added to provide a concise narrative overview of this program.

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I. Summary of PSD Program

The purpose of this summary is to help those people who are unfamiliar with the PSD program gain an understanding of it. Because this summary seeks to condense the basic PSD rules, it may not precisely reflect the amendments announced in this notice. Should there be any apparent inconsistency between the summary and the remainder of the preamble and the regulations, the remaining preamble and the regulations shall govern.

A. PSD Allows Industrial Growth Within Specific Air Quality Goals

The basic goals of the prevention of significant air quality deterioration (PSD) regulations are (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent the development of any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards; and (3) to preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value, such as national parks and wilderness areas.

States are required to develop SIP revisions for PSD pursuant to regulations published today. *See* 40 CFR 51.24, "Requirements for Preparation, Adoption and Submittal of Implementation Plans." If EPA approves the proposed PSD plan, the state can then implement its own program. In the absence of an approved state PSD plan, another portion of today's regulations will govern PSD review. *See* 40 CFR 52.21, "Approval and Promulgation of Implementation Plans." EPA will implement this regulation itself if the state does not submit an approvable PSD program of its own.

States can identify in their SIPs the local land use goals for each clean area through a system of area classifications. A "clean" area is one whose air quality is better than that required by the National Ambient Air Quality Standards. Each classification differs in the amount of growth it will permit before significant air quality deterioration would be deemed to occur. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable maximum allowable increase ("increment"), the amount of which varies with the classification of the area. The reference point for determining air quality deterioration in an area is the baseline concentration, which is essentially the ambient concentration existing at the time of the first PSD permit application submittal affecting that area. To date, only PSD increments for sulfur dioxide and particulate matter have been established. Increments or alternatives

to increments are currently under investigation for the other criteria pollutants.

There are three types of area classifications. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration, while Class II areas can accommodate normal well-managed industrial growth. Class III designations have the largest increments and are appropriate for areas desiring a larger amount of development. In no case would the air quality of an area be allowed to deteriorate beyond the National Ambient Air Quality Standards. Except for certain wilderness areas and national parks, which are mandatory Class I areas, all clean areas of the country were initially designated as Class II. Flexibility exists under the Act to adjust most of these designations, except for those mandated by Congress.

The principal mechanism within the SIP to implement the objectives of the PSD program is the preconstruction review process. These provisions require that new major stationary sources and major modifications are carefully reviewed prior to construction to ensure compliance with the National Ambient Air Quality Standards, the applicable PSD air quality increments, and the requirements to apply the best available control technology on the project's pollutant emissions. In addition, proposed SIP relaxations which would limit further use of increment must be reviewed for their anticipated impact and not be approved if the applicable increment would be violated. The SIP must also contain PSD provisions for periodically reviewing all emissions increases, including those which occur outside the SIP revision and the new source review (NSR) process, and for restoring clean air when such increases cause violations of the applicable PSD increment. This corrective action may require additional controls on existing emissions sources which contribute to the problem.

B. Who is Subject to the Prevention of Significant Deterioration Regulations?

The requirements of today's PSD regulations apply to major stationary sources and major modifications which meet certain criteria concerning the geographic location, type of pollutants to be emitted, and timing of proposed construction. No source or modification subject to today's rules may be constructed without a permit which states that the stationary source or modification would meet all applicable PSD requirements. This section summarizes how PSD review as modified in response to *Alabama Power* will apply.

The primary criterion in determining PSD applicability is whether the proposed project is sufficiently large (in terms of its emissions) to be a major stationary source or major modification. Source size, for applicability purposes, is defined in terms of "potential to emit." "Potential to emit" means the capability at maximum design capacity to emit a pollutant after the application of all required air pollution control equipment and after taking into account all federally enforceable requirements restricting the type or amount of source operation. A "major stationary source" is any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. A stationary source generally includes all pollutant-emitting activities which belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control. Pollutant activities which belong to the same major group as defined in a standard industrial classification scheme developed by the Office of Management and Budget are considered part of the same industrial grouping. (*See* SOURCE).

A "major modification" is generally a physical change in or a change in the method of operation of a major stationary source which would result in a significant net emissions increase in the emissions of any regulated pollutant. In determining if a proposed increase would cause a significant *net* increase to occur, several detailed calculations must be performed. First, the source owner must quantify the amount of the proposed emissions increase. This amount will generally be the potential to emit of the new or modified unit. Second, the owner must document and quantify all emissions increases and decreases that have occurred or will occur contemporaneously (generally within the past five years) and have not been evaluated as part of a PSD review. The value of each contemporaneous decrease and increase is generally determined by subtracting the old level of actual emissions from the new or revised one. Third, the proposed emissions changes and the unreviewed contemporaneous changes must then be totalled. Finally, if there is a resultant *net* emissions increase that is larger than certain values specified in the regulations, the modification is major and subject to PSD review.

Certain changes are exempted from the definition of major modification. These include: (1) routine maintenance, repair, and replacement; (2) use of an alternative fuel or raw material by revision of an order under sections (2)(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation); (3) use of an alternative fuel by reason of an order or rule under section 125 of the Clean Air Act; (4) use of an alternative fuel at a steam generating unit to the extent it is generated from municipal solid waste; (5) use of an alternative fuel which the source is capable of accommodating; and (6) an increase in the hours of operation, or the production rate. The last two exemptions can be used ony if the corresponding change is not prohibited by certain permit conditions established after January 6, 1975.

If a source or modification thus qualifies as major, its prospective location or existing location must also qualify as a PSD area, in order for PSD review to apply. A PSD area is one formally designated by the state as "attainment" or "unclassifiable" for *any* pollutant for which a national ambient air quality standard exists. This geographic applicability test does not take into account what new pollutant emissions caused the construction to be major. It looks simply at whether the source is major for any pollutant and will be located in a PSD area.

Once a source applicant has determined that proposed construction falls under PSD based on the above size and location tests, it must then assess whether the pollutants the project would emit are or are subject to PSD. If a new major stationary source emits pollutants for which the area it locates in is designated nonattainment, then the source is exempt from PSD review for those pollutants. These sources must, however, meet the applicable requirements of NSR for each nonattainment pollutant. Similarly, if a major modification to be constructed in a PSD area involves changes only for nonattainment pollutants then the source is not subject to PSD. These modifications must meet the appropriate nonattainment NSR under the SIP for the pollutant. Once the question of NSR jurisdiction is resolved, then the PSD review applies to all significant emissions increases of regulated air pollutants. Specific numerical cutoffs which define what emissions increases are "significant" have been spelled out in the regulations. These pollutant-

specific cutoffs can exempt a source from PSD review for a particular pollutant, except where the proposed construction would adversely impact a Class I area.

If a proposed source or modification would be subject to PSD review based on size, location, and pollutants emitted, then its construction schedule must meet certain tests before the PSD rules promulgated today would apply. All major construction otherwise qualifying for PSD review would not need a PSD permit under these regulations if the proposed construction: (1) was subject to the old PSD rules, has submitted a complete application under these rules before today, and was or is subsequently approved to construct based on this application; or (2) was not subject to the old PSD rules, has received all federal, state, and local air permits needed before today and commences construction in a continuous fashion at the proposed site within a reasonable time.

Finally, the PSD regulations contain some specific exceptions for some forms of source construction. The requirements of today's regulations do not apply to any major stationary source or major modification that is: (1) a nonprofit health or educational institution (only if such exemption is requested by the governor); or (2) a portable source which has already received a PSD permit and proposes relocation.

C. What Must A Source or Modification Do To Obtain A PSD Permit?

1. It must apply the best available control technology.

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure application of best available control technology (BACT). During each analysis, which will be done on a case-by-case basis, the reviewing authority will evaluate the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority will then specify an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be recommended which would not meet any applicable standard of performance under 40 CFR Parts 60 and 61.

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use source design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent. For example, if an immense pile of uncovered coal emits coal dust into the atmosphere, it woud make little sense to impose an emission, standard, since measuring the amount of coal dust rising off the pile is nearly impossible. A much more direct approach to controlling emissions is, for example, requiring the owner to wet the coal pile daily. This type of standard or practice will be equivalent to an emissions limitation for purposes of the BACT requirement.

2. It must conduct an ambient air quality analysis.

Each PSD source or modification must perform an air quality analysis to demonstrate that its new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment. This analysis ensures that the existing air quality is better than that required by national standards and that baseline air quality will not be degraded beyond the applicable PSD increment.

Each proposed major construction project subject to PSD must first assess the existing air quality for each regulated air pollutant that it emits in the affected area. This analysis requirement does not apply to pollutants for which the new emissions proposed by the applicant would cause insignificant ambient impacts. Today's PSD regulations define pollutant-specific impacts that are typically considered inconsequential and that can be exempted from analysis, unless existing air quality is poor or adverse impacts to a Class I area are in question. For pollutants for which a NAAQS exists, the applicant must provide ambient monitoring data that represent air quality levels in the year's period preceding the PSD application. Where no existing data are judged representative or adequate, then the source applicant must conduct its own monitoring program. This is often the case where the applicant will be establishing the baseline concentration for the affected area. Typically air quality dispersion modeling is used by applicants to support or extend the assessment made with gathered monitoring data. For pollutants for which there is no NAAQS, the required analysis will normally be based on dispersion modeling alone.

Source applicants who are subject to the ambient analysis requirement for sulfur dioxide or particulate matter must also perform an analysis to compute how much of the PSD increment remains available to them. In general the amount of increment that is available depends on certain changes in actual emission. First, actual emissions changes occurring after January 6, 1975 which are associated with physical changes or changes in the method of operation at a major stationary source can affect the available increment. Accordingly, cleanup adds to the available growth margin while new emissions diminish it. Second, all changes in emissions, including those from minor sources and other types of changes at major sources, affect the available increment provided they occur after the baseline date. The baseline date is essentially the time that the first PSD application affecting the area is filed.

Once the question of how much increment remains is resolved, then the applicant must demonstrate that his proposed new emissions would not exceed the remaining PSD increment. Where a proposed project would cause a new violation of the increment or contribute to an existing violation, it cannot be approved. Existing violations must be entirely corrected before PSD sources which affect the area can be approved.

3. It must analyze impacts to soils, vegetation, and visibility.

An applicant is required to analyze whether its proposed emissions increases would impair visibility, or impact on soils or vegetation. Not only must the applicant look at the direct effect of source emissions on these resources, but it also must consider the impacts from general commercial, residential, industrial and other growth associated with the proposed source or modification. The results of this analysis may be used to determine if the project would have an adverse impact on a Class I area.

4. It must not adversely impact a Class I area.

If the reviewing authority receives a PSD permit application for a source that could impact a Class I area, it will immediately notify the Federal Land Manager and the federal official charged with direct responsibility for managing these lands. These officials are responsible for protecting the air quality-related values in Class I areas and for consulting with the reviewing authority to determine whether any proposed construction will adversely affect such values. If the Federal Land Manager demonstrates that emissions from a proposed source or modification would impair air quality-related values, even though the emissions levels would not cause a violation of the allowable air quality increment, the Federal Land

Manager may recommend that the reviewing authority deny the permit.

5. Its application must undergo adequate public participation.

The regulations solicit and encourage participation by the general public, industry, and other affected persons impacted by the proposed major source or major modification. Specific public notice requirements and a public comment period are required before the PSD review agency takes final action on a PSD application. The public notice must indicate whether the reviewing authority proposed permit approval, denial, or conditional approval of a proposed major source or major modification. Consideration is given to all comments received provided they are relevant to the scope of the review. Where requested, or at its own discretion, the reviewing authority may conduct a public hearing to help clarify the issues and obtain additional information to assist in making a final permit decision.

6. It must start construction on time.

The source owner, once receiving a PSD permit, must start construction within a reasonable period of time (typically within 18 months of approval) and must stay on a continuous construction schedule. Normally, long delays will invalidate the permit.

II. Background

On August 7, 1977, the President signed the Clean Air Act Amendments of 1977 (1977 Amendments) into law. Those amendments established, in the form of Part C of Title I of the Clean Air Act (CAA), a set of requirements for the prevention of significant deterioration (PSD) of air quality in "clean air" areas. Sections 160–69, 42 U.S.C. 7470–79. The requirements for preconstruction review of new stationary sources and modifications in Part C follow the outline of the PSD regulations that EPA promulgated in 1974, but are more elaborate and in many ways more stringent. Part C also requires that each state implementation plan (SIP) contain the new PSD requirements.

In response to Part C, EPA promulgated two sets of PSD regulations on June 19, 1978. One set specified the minimum requirements that a PSD SIP revision would have to contain in order to warrant EPA approval. *See* 43 FR 26380 (codified at 40 CFR 51.24 (1979)) (hereinafter, the "1978 Part 51 regulations") The other set comprehensively amended the 1974 PSD regulations, incorporating into them the new Part C requirements. 43 FR 26388 (codified at 40 CFR 52.21 (1979)) (hereinafter, the "1978 Part 52 regulations"). EPA intended that, until it had approved a PSD SIP revision for a state, the permitting of new sources and modifications for PSD purposes would continue under the 1978 Part 52 regulations.

On June 18, 1979, the United States Court of Appeals for the District of Columbia Circuit issued a decision that upheld some of the substantive provisions of both the 1978 Part 51 and Part 52 regulations and overturned others. *Alabama Power Company v. Costle*, 13 ERC 1225. In its opinion, the court merely summarized its holdings, but promised to issue supplemental opinions after it had considered any petitions for reconsideration. In an order that accompanied the summary opinion, the court stayed the effect of its decision until it had issued the supplemental opinion. The purpose of that procedure, the court explained, was "to enable EPA to proceed as soon as possible to commence rulemaking or other proceedings necessary to promulgate those revisions in the PSD regulations required by [the court's] rulings * * *." *Id.* at 1227.

By a notice that appeared in the Federal Register for September 5, 1979, EPA began the process the court had in mind. 44 FR 51924. There EPA proposed various amendments to the PSD regulations that were to replace the provisions the court had held invalid, for instance, the definitions of "source," "modification," and "potential to emit." EPA also proposed amendments that were to add entirely new provisions to supplement the replacement provisions, for instance, the *de minimis* exemptions.

Prior to September, EPA had issued, also in response to the 1977 Amendments, various regulations and guidelines relating to the construction of new sources and modifications in and near "nonattainment" areas. In January 1979, the Agency revised its Emission Offset Interpretative Ruling ("Offset Ruling"), which now appears at 40 CFR Part 51, Appendix S (1979). Then, in April 1979, EPA issued a guideline entitled "General Preamble for Proposed Rulemaking on Approval of Plan Revisions for Nonattainment Areas." 44 FR 20372.[1] Finally, in July 1979, EPA issued an interpretative rule concerning certain statutory restrictions on new construction in nonattainment areas. 44 FR 38471 ("construction moratorium").[2] EPA also asked for comment on certain issues concerning new construction in such areas. 44 FR 38583.

In the September Federal Register notice, EPA also proposed various changes to those nonattainment regulations and guidelines. The purpose of those changes generally was to conform those regulations and guidelines to the decisions in *Alabama Power* concerning the statutory terms "source," "modification," and "potential to emit."

On September 18, 1979, EPA announced that it would hold public hearings on the September proposal on October 15 and 16 in Washington, D.C., and on October 18 and 19 in San Francisco. *See* 44 FR 54069. At the same time, the Agency set November 18 as the deadline for submitting information rebutting or supplementing any presentation at the hearings. Subsequently, EPA held the public hearings as scheduled.

On October 4, 1979, EPA announced various corrections to technical errors in the September proposal. 44 FR 57107. At the same time, it extended the period for submitting written comments until November 5, 1979. It added that it would hold the rulemaking docket open until November 18, 1979, not only for information rebutting or supplementing any presentation at the hearings, but also for information rebutting or supplementing any written comment.

On November 9, 1979, EPA announced that it had recently released for public comment a draft of a revision of the *Ambient Monitoring Guideline for Prevention of Significant Deterioration (PSD)* (OAQPS 1.2–096), which the Agency had originally published in May 1978. 44 FR 65084. EPA also announced that it would accept any written comments on the draft until December 10, 1979.

On December 14, 1979, the Court of Appeals handed down its final opinion in *Alabama Power*. 13 ERC 1993. Subsequently, in order to avoid the uncertainty and confusion that would occur in PSD permitting if the final opinion came into effect before EPA completed the rulemaking, EPA and many of the other parties to the litigation petitioned the court to keep the final opinion from coming into effect until June 2, 1980. On March 14, 1980, the court granted the request.

On May 30, 1980, EPA and other parties to the litigation again petitioned the court, requesting a further extension of time until July 18, 1980. The court granted an extension, to July 28, on June 23, 1980.

On January 30, 1980, EPA announced that it would reopen the rulemaking docket for the receipt of written

[1] For supplements to the General Preamble, *See* 44 FR 38583 (July 2, 1979); 44 FR 50371 (August 28, 1979); 44 FR 51924, 51928–29 (September 5, 1979); 44 FR 53761 (September 17, 1979); and 44 FR 67182 (November 23, 1979).

[2] For a fuller description of those nonattainment regulations and guidelines, *See* 44 FR 51925 and 45 FR 31304–05.

comments on various aspects of the rulemaking, including the final opinion of the court, certain issues that the Agency described in the notice, the redraft of the monitoring guidelines, and various meetings between EPA and others. 45 FR 6802.

On February 5, 1980, EPA issued a stay of the 1978 Part 52 PSD regulations as to certain sources and modifications. 45 FR 7800. The stay was effective as of January 30, 1980. Its purpose was "to relieve from the permitting requirements of the 1978 PSD regulations roughly those sources and modifications that would not be subject to the permitting requirements of valid replacement regulations that would comport with the *Alabama Power* opinion." *Id.*

On May 13, 1980, EPA promulgated a stay of the Offset Ruling and the construction moratorium that is similar to the PSD stay. *See* 45 FR 31304. On the same day, EPA promulgated certain amendments to the Offset Ruling, the regulations relating to new source review at 40 CFR 51.18, and the construction moratorium. Those amendments established the geographic applicability of the various nonattainment requirements relating to the construction of new sources and modifications. 44 FR 31307. Those amendments embody EPA's responses to many of the comments on the September proposal.

Finally, on May 19, 1980, EPA promulgated regulations aimed at consolidating and unifying various permit requirements and procedures. 45 FR 33290. Those new regulations contain provisions which will govern the processing of applications for permits under the new Part 52 PSD regulations.

During the course of the rulemaking that EPA began in September, it received approximately 375 written comments. The discussion that follows summarizes the proposals, the comments on them, EPA's responses, and the final provisions.

III. Highlights

Several significant changes from the September 5, 1979 proposal have occurred. These changes include the addition of certain provisions not addressed by the September 5, 1979 proposal but which are necessary under the Act. Several regulatory provisions which are unchanged in substance by today's notice have also been reprinted to clarify the effects of any revised paragraph numbering.

A. *Transition:* The proposed transition scheme for phasing in the additional monitoring requirements has been expanded to require no new monitoring requirements for PSD applications submitted and complete within 10 months of the promulgation date. In addition, today's rules allow less than a full year of monitoring data to be included with PSD applications filed after the above times but before 18 months after the promulgation date. PSD applications filed later than 18 months from the date of promulgation will be subject to the full new monitoring requirements.

B. *Potentiel To Emit:* Potential to emit is the maximum design capacity of the source, except as constrained by federally enforceable permit conditions. This would include permit conditions restricting hours or type of source operation.

C. *50-Ton Exemption:* Today's regulations essentially delete the "50-Ton Exemption" for both nonattainment and PSD. The eligibility date for the section 165(b) exemption has been changed from August 7, 1977 to March 1, 1978.

D. *Fugitive Emissions:* For the purpose of PSD and nonattainment, "fugitive emissions" now means those emissions released directly into the atmosphere, which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Fugitive emissions are not to be considered in determining whether a source would be a major source, except when such emissions come from specified source categories.

E. *Fugitive Dust:* Today's regulations promulgate the proposed deletion of the "fugitive dust exemption" from the applicable provisions of both PSD and the Offset Ruling.

F. *Stationary Source:* The definition of source for PSD purposes has been made more liberal than the previous regulations. Under today's rules, a PSD source is a grouping of all pollutant emitting activities at one location and owned or under the control of the same person or persons. This generally relates to the common notion of a plant. Smaller portions of such a plant no longer will be examined for applicability purposes. For added clarification, pollutant-emitting activities will now be considered part of the same "plant" if they belong to the same "major group" as described in the Standard Industrial Classification Manual. At this time, however, the Agency has decided not to change its previous approach to defining source for nonattainment purposes. Therefore, today's rules continue to incorporate the "dual definition" concept of source which requires consideration of overall emissions from a "plant" and from each "installation" within that plant. In a change from the proposal, this dual definition will apply to major sources in all nonattainment areas designated under section 107 of the Act, regardless of SIP approvability or degree of completion.

G. *Modification:* The definition and treatment of modifications have been changed since the September 5, 1979 proposal. The concept of accumulating minor changes made at an existing minor source until the sum was equivalent to a major stationary source has been deleted. Rather, a source must now qualify as a major stationary source prior to making a modification to become subject to review, unless the change itself is greater than 100 or 250 tons per year. Contemporaneous changes now generally refer to emissions increases and decreases occurring within the same 5-year time period unless the state opts for a different time period in its Part D SIP or PSD program. Reductions, to be creditable, must be enforceable under the SIP before the contemporaneous emission increase would begin construction. Such reductions, as well as significant increases, will be quantitatively assessed on the basis of an "actual emissions" baseline, rather than a "potential to emit" baseline, as was proposed. "Reconstruction" (*i.e.*, 50% or more capital replacement) has been deleted from PSD but has been retained for nonattainment NSR, including the prohibition on construction.

H. *"De Minimis" Exemptions:* Three types of changes from the September 5 proposal appear in today's regulations: (1) different numbers have been developed for defining significant emissions from new sources and significant net emissions increases from modifications; (2) new air quality *de minimis* numbers have been generated and can only be used to exempt PSD sources from the ambient monitoring requirements; and (3) a ten kilometer proximity cutoff has been specified to indicate when a source, regardless of pollutant emissions, must be prepared to demonstrate that no 24-hour impact greater than 1 $\mu g/m^3$ would occur in the Class I area.

I. *Geographic Applicability:* PSD will generally apply only if the otherwise subject major construction locates in a section 107 area which is designated attainment or unclassified under section 107 for any criteria pollutant (regardless of what pollutants the proposed construction would emit or what pollutant qualified it as major). An exception to this rule is that no PSD permit is required for major construction which emits only the pollutant for which the area of location is nonattainment.

J. *Pollutant Applicability:* Any net significant emissions increase of any pollutant subject to regulation under the Act (not just those pollutants for which the source is major) now qualifies as a PSD modification. Nonattainment review will continue to focus on only the major nonattainment pollutant. No PSD review will be required for a given criteria pollutant, if a source would construct in an area designated nonattainment for that pollutant.

K. *Baseline Area/Date:* Baseline area now refers to all section 107 areas which are designated attainment or unclassified for PM or SO_2 (as may be redesignated) in which the PSD source triggering the baseline date would locate or would have an annual air quality impact equal to or greater than 1 $\mu g/m^3$. Interstate impacts, however, do not trigger baseline date. This differs from the proposal, which focused on the AQCR rather than the designated area. Baseline dates are pollutant specific and can be established by the first PSD application of a source with significant emissions of the applicable pollutant. States will have the flexibility to redesignate clean or unclassified areas under section 107 and thereby remove baseline dates for certain areas. However, no redesignation may subdivide the impact area (>1 $\mu g/m^3$) of the source triggering a baseline date.

L. *Best Available Control Technology:* Today's regulations reflect the proposal with one exception. A provision has been added that requires BACT for modifications only when both a net emissions increase occurs at the changed unit(s) and a significant net emissions increase occurs at the plant; BACT applies only to the units actually modified.

M. *Monitoring:* The proposed transition scheme for phasing in the additional monitoring requirements will provide relief for sources covered under the existing regulations that are in the process of monitoring and offer allowances for setup time of monitors in gathering the required data.

N. *Notification:* The notification provisions appearing in the September 5, 1979 proposal have been deleted from today's regulations.

O. *PSD SIP Revisions:* The requirements proposed on September 5 for governing the development of PSD SIP submittals are essentially unchanged. These regulations allow limited flexibility in the development of different but equally effective state plans.

P. *Increment Consumption:* A discussion has been included in the preamble to summarize the effects that the *Alabama Power* decision has had on increment tracking. This section also discusses how certain SIP related issues are to be addressed, such as the Gulf Coast problem (SIP shows a theoretical increment violation in a clean area, unrelated to actual air quality impact) and temporary SIP relaxations. (SIP would be relaxed and only temporary emissions would occur.)

Q. *Public Participation:* The requirements of paragraph (r) of § 52.21 have been replaced with the public participation procedures associated with the consolidated permit regulations (40 CFR 124).

IV. Transition

This section focuses on those provisions of the final PSD and nonattainment regulations which govern the transition from the preexisting requirements to the new ones. It begins with a discussion of the new transition provisions of the Part 52 PSD regulations and then deals in turn with the transition provisions of the Part 51 PSD regulations, the Offset Ruling, the Part 51 nonattainment regulations, and finally the construction moratorium.

A. Part 52 PSD Regulations

The new transition provisions of the Part 52 PSD regulations fall into three categories: those that relate to the new coverage of the regulations, those that relate to the new requirements for best available control technology (BACT) and air quality assessments, and those that relate to the new procedural requirements. The discussion which follows deals with each in that order.

1. *Coverage.*

a. *Proposed transition provisions:* The preconstruction permit requirements of the 1978 Part 52 regulations applied to a certain class of projects that emit or would emit pollutants. The keystone of those regulations, section 52.21(i)(1), provided that "[n]o major stationary source of major modification shall be constructed unless the [permit] requirements of [the Part 52 regulations] have been met." It established the general rule that the permit requirements applied to any "major stationary source" or "major modification." The balance of section 52.21(i) then listed certain exceptions to that general rule. The main exceptions established various "grandfather" exemptions. The permit requirements of the regulations applied, therefore, to any pollutant-emitting project that was "major" and had no "grandfather" status.

In September 1979, EPA proposed to establish new Part 52 PSD regulations whose coverage would be substantially different from that of the 1978 regulations. First, it proposed to define "major stationary source" differently than it had defined that term in the 1978 regulations. Under the 1978 regulations, whether a "source" was "major" depended upon whether its "potential to emit" any pollutant regulated under the Act would equal or exceed certain thresholds. "Potential to emit" referred largely to the maximum rate at which a "source" would emit a pollutant *without* control equipment. Under the amendments that EPA proposed in September, "potential to emit" would be the maximum rate at which a "source" would emit a pollutant *with* control equipment. Second, EPA proposed to define "major modification" differently than it had defined that term in the 1978 regulations. There, a "major modification" was any change at a "source" that would increase the "potential to emit" of the "source" by 100 tons per year of any pollutant regulated under the Act, or 250 tons per year, depending on source type and ignoring any emission reductions. Under the amendments that EPA proposed in September, "major modification" would have become any change at a "source" that would result in a *significant net* increase in the "potential to emit" of the "source." "Significant" is defined as emissions greater than certain *de minimis* values. Finally, EPA proposed to limit the geographic applicability of the PSD permit requirements by adding an exception to section 52.21(i) that would exclude a "source" or "modification" from PSD review on the basis of its location.[3]

Amendments of the sort that EPA proposed in September would have left many projects that previously fell or would have fallen within the coverage of the 1978 Part 52 regulations outside the coverage of the resulting Part 52 regulation. For instance, many new "sources" that were "major" under the 1978 regulations would not have been "major" under the proposed amendments, because while their maximum uncontrolled emissions would exceed the applicable thresholds, their maximum controlled emissions would not.

Of those projects that were or would have been subject to the PSD permit requirements under the 1978 PSD regulations, but not under the proposed

[3] Specifically, EPA proposed that the permit requirements would apply only to any "major stationary source" or "major modification" that would be located in an area designated under section 107 of the Act as attainment or unclassifiable for a pollutant for which the "source" or "modification" would be major or would significantly impact an area in another state which is designated as attainment or unclassifiable for any such pollutant.

amendments, some have already received a PSD permit, while others have not. In September, EPA proposed to put both sets of projects outside the reach of the permit requirements as soon as possible by putting the new definitions of "potential to emit" and "modification" and the new limitation on geographic applicability into effect immediately upon their promulgation. *See* 44 FR 51927. But EPA also proposed that any permit that had already been issued would remain in effect, binding and particular project to its terms, until the permit had been rescinded under a proposed paragraph (w) or had expired under an existing paragraph (s). *See id.* at 51927, 51956. Under paragraph (w), a permittee would have been able to obtain rescission only if the permittee filed a complete application with the issuing authority within 90 days after paragraph (w) had come into effect.

Amendments of the sort that EPA proposed in September would also have brought some projects that previously fell or would have fallen outside the coverage of the 1978 regulations inside the coverage of the Part 52 regulations. For instance, many changes at a "source" that would result in a *gross* increase in "potential to emit" well below 100 or 250 tons per year might nevertheless result in a significant net increase.

In September, EPA proposed to exempt from PSD review certain of these projects that fell or would have fallen beyond the reach of the PSD permit requirements under the 1978 regulations, but not under the proposed amendments. In particular, EPA proposed to "grandfather" any such project which before the promulgation of the new amendments had received each preconstruction permit that the state implementation plan (SIP) required and which will have "commenced" construction within 18 months after promulgation. *See id.* at 51928 (first column), 51953 (proposed § 52.21(i)(7);) 44 FR 57108 (items B(1) and (C)(2)).

Finally, EPA proposed to add another new grandfather provision to § 52.21(i). That provision would have stated that the permit requirements of those regulations do not apply to any "source" or "modification" on which construction "commenced" before August 7, 1977, the date of enactment of the 1977 Amendments. *See id.* at 51928 (first column), 51953 (proposed § 52.21(i)(3)). The purpose of the proposal was merely to state in regulatory form what section 168(b) of the Act, 42 U.S.C. 7478(b), already provides.

b. *Comments and final action on the proposed transition provisions relating to coverage:* EPA received no comments on its proposal to put the new definitions of "potential to emit" and "modification" and the new limitation on geographic applicability into effect immediately upon promulgation. EPA therefore has put those provisions into effect as of the date this notice appears in the **Federal Register**. Some projects that were within the coverage of the 1978 Part 52 regulations, but have yet to receive a PSD permit, are now outside the coverage of the new Part 52 regulations, since the prohibition on construction without a permit in § 52.21(i)(1)(i) no longer applies to them. As a result, construction on them may begin immediately.[4] Because further delay is pointless, and might be harmful in some cases, EPA finds that it has "good cause" to put the new applicability provisions into effect immediately upon promulgation, within the meaning of section 4(d)(3) of the Administrative Procedure Act (APA), 5 U.S.C. 553(d)(3). *See also* APA 4(d)(1), 5 U.S.C. 553(d)(1).

EPA did receive numerous comments on its proposal to rescind certain permits, and to treat them as binding unless and until rescinded. While one commenter agreed with the proposal, most did not. They objected primarily to two aspects of the proposal: first, that it would place on the permittee the dual burden of coming forward with an application for rescission and of providing proof that the project in question does fall outside the coverage of the new Part 52 regulations and, second, that it would bar rescission if the permittee failed to file a complete application within a certain period of time. The commenters argued that EPA had no authority originally to require a permit for any project that falls outside the coverage of the new regulations and that it therefore has no authority now either to place the burden of coming forward and of proof on a permittee or to keep a rescindable permit in effect merely because of a failure to file a complete application for rescission by a certain time.

In response, EPA has promulgated a new provision, § 52.21(w), which does place the burden of coming forward and of proof on the permittee, but imposes no deadline for filing an application. Whether EPA had authority originally to require a permit for a project that falls outside the coverage of the new regulations is immaterial. EPA has authority under section 301(a)(1) of the Act, 42 U.S.C. 7601(a)(1), to fashion within reason the regulatory tools it needs to carry out its tasks. Here EPA has undertaken not only to release certain PSD permittees from the constraints of their PSD permits, but also to settle as finally, as publicly, and as quickly as possible which old permits are binding and which are not. Prospective applicants, in order to prepare applications, and permitting authorities, in order to meet their obligations under the PSD regulations, must assess increment consumption. Confusion and uncertainty over whether particular projects are subject to the emissions limitations in their PSD permits can only frustrate efforts to assess increment consumption. New § 52.21(w) maximizes EPA's ability to perform satisfactorily the tasks it has undertaken.

First, by stating explicitly that a permit generally remains in effect until rescinded, § 52.21(w) gives each permittee with a rescindable permit a strong reason to bring it before the reviewing authority as soon as possible. Second, by putting the burdens of coming forward and of proof on the permittee, § 52.21(w) ensures that the reviewing authority will spend its time efficiently and will have adequate information with which to make a sound decision. Third, by establishing that only the reviewing authority may rescind a permit, the provision promotes the soundness and therefore the finality of the rescission, since the reviewing authority will have the expertise and objectivity necessary to check adequately whether the permittee has applied the intricate applicability rules correctly. Finally, by requiring that the reviewing authority publish each rescission, § 52.21(w) ensures that the status of each permit will be in the public record.

Certain commenters suggested two alternatives to EPA's proposed rescission provision. One alternative was to declare upon promulgation that any PSD permit for a project that falls outside the coverage of the new regulations is null and void as of that time, but that any permittee which concludes it holds such a permit must send the reviewing authority a bare notice of that conclusion. The other alternative was to require any such permittee to send the reviewing authority an application for rescission and to establish that the failure of the reviewing authority to act on the application within a certain period would operate to grant the application. EPA has decided to adopt neither alternative. Under both, a project that should not be able to escape PSD

[4] The partial stay of the 1978 regulations that EPA issued in January 1980 has probably already relieved most of those projects from the permit requirements of those regulations.

constraints would be able to escape them merely because of an oversight or a manpower deficiency. EPA, however, has no authority to allow escape from review on that basis.

Certain commenters also objected to other aspects of the proposed rescission provision. In particular, one commenter asserted that proposed § 52.21(w)(3), which would say that "[t]he permitting authority may approve" an application that does show that the permit is rescindable, should state instead that "[t]he permitting authority *shall* approve" such an application. (Emphasis added.) EPA agrees, and has placed the necessary mandatory language in the final provision. Other commenters urged that the final provision recognize the possibility that a permittee may wish to obtain rescission of only certain elements of a permit. In response, EPA has introduced language under which the reviewing authority may rescind only certain elements, if that is appropriate in the particular case.

With respect to the rescission provision, it should be noted that rescission of a permit would in no way affect any other limitations on the project that may apply by virtue of the SIP or a state permit. It should also be noted that, if a source or modification whose permit is rescinded were later found to be causing or contributing to an increment violation, additional controls might be necessary. *See* 40 CFR 51.24 (a)(3)(1979).

EPA received many comments on its proposal to "grandfather" certain projects that fall outside the coverage of the 1978 regulations, but not the new Part 52 regulations. Two commenters, while not focusing specifically on that proposal, expressed general opposition to "grandfathering" any project that would otherwise fall within the coverage of the new regulations. In its view, EPA should adhere to the transitional rules that it established in the 1978 regulations, so that in general a project would escape PSD review under the new Part 52 regulations only if certain permits were obtained for it by March 1, 1978, and construction "commenced" on it by March 19, 1979.

EPA disagrees that it should or must adhere to the transitional rules in the 1978 regulations in deciding which of the projects in question here should have to get a PSD permit. Part C of Title I of the Act contains two provisions, sections 165(a) and 168, which describe how the PSD permit requirements of Part C are to be implemented. Those sections, however, contradict each other irreconcilably. *See Citizens to Save Spencer County* v. *EPA*, 600 F.2d 844, 851–54, 860–73 (D.C. Cir., 1979). EPA has authority under section 301(a)(1) of the Act, therefore, to set transitional rules which accommodate reasonably the purposes and concerns behind the two contradictory provisions. *See id.* at 873–74.

The court in *Citizens to Save Spencer County* identified those "considerations" as follows:

> (1) enhanced protection of the environmental quality of the nation's air; (2) minimization of economic dislocation and loss as a result of such enhanced protection; (3) a heightened enforcement role for states * * *; and (4) facilitation of an efficient administrative transition from enforcement of the "old" to "new" preconstruction review requirements. (*Id.* at 889 (footnotes omitted).)

Here, the proposed grandfather provision would reasonably accommodate those considerations. Most of the projects in question are modifications that would result in a significant net increase in the maximum controlled emissions of the "source," but not in a gross increase in uncontrolled emissions equal to or above 100 or 250 tons per year. This discrete group of small modifications, even in the aggregate, have a relatively minor effect on air quality. But, because they are numerous, delaying them by imposing new PSD requirements could frustrate economic development. The proposed provision would strike a rough balance between the benefits and the cost of applying PSD to those projects by allowing any company that has already obtained each of the preconstruction permits otherwise necessary under the SIP to proceed to construction without delay. To require such a company to obtain a PSD permit could mean substantial delays. To impose such delays here would be excessive.[5]

One commenter urged EPA to promulgate a grandfather provision that would use the date of complete application instead of the date of permit issuance. The commenter was concerned that the proposed provision would treat unfairly a company that obtained the last permit necessary under the SIP just a day or two after the date this notice appeared in the **Federal Register**. Use of such a date, however, might exempt many more projects from review. Hence, in EPA's view, it would fail to give adequate expression to the interests behind section 165, especially the goal of protecting air quality.

[5] Even if the conflict between sections 165(a) and 168 had not conferred on EPA the discretion to exempt certain projects that would otherwise be subject to PSD review for the first time, EPA would have authority under section 301(a)(1) to exempt those projects in order to phase-in new requirements on a reasonable schedule.

Certain commenters pointed out that a company might be unable to "commence construction" within the proposed 18-month period, because it might be unable to get sufficiently in advance any preconstruction permits that federal or state law outside the SIP might require. They recommended that EPA set the deadline 18 months from issuance of the last necessary federal authorization. That recommendation parallels a proposal EPA made in July 1979 to amend the grandfather provisions of the 1978 regulations so as to extend the "commence" construction deadlines in those provisions generally to a date nine months from the issuance of the last necessary federal authorization. *See* 44 FR 42722. EPA has not yet completed that rulemaking. When it does, it will decide whether to accept the recommendation of the commenters here.

EPA has decided to promulgate the grandfather provision basically as proposed. *See* § 52.21(i)(4)(v). The final provision contains the following clause: "the owner or operator * * * obtained all final federal, state and local preconstruction approvals or permits necessary" under the SIP by a certain date. EPA intends that clause to refer only to the date on which the reviewing authority issues the permit. For emissions increases as a result of SIP relaxations, the appropriate date is the effective date of final EPA approval. Because of the construction moratorium, 40 CFR 52.24, 44 FR 38471, some SIP permits may be issued before the time that the owner or operator is allowed to begin construction. Nevertheless, in EPA's view, the owner or operator "obtains" the permit when the reviewing authority issues it, even if permission to begin construction takes effect subsequently.

EPA received no comments on its proposal to put into regulatory language the provision in section 168(b) of the Act that only the PSD regulations in effect before August 7, 1977, apply to any project on which construction "commenced" by then. Hence, EPA is promulgating that provision basically as proposed. *See* section 52.21(i)(4)(i).

2. *Substantive Provisions Relating to BACT.*

a. *Proposed transition provisions:* In September, EPA proposed certain new substantive requirements. One of the new requirements was that a project apply BACT for each pollutant regulated under the Act that the project would emit in a significant, but "minor" amount. Under the 1978 Part 52 regulations, a project has to apply BACT only for each pollutant regulated under the Act that the project would emit in a

"major" amount. EPA added that it intended to put the new BACT requirement into effect immediately upon its promulgation.

In proposing the new BACT requirement, EPA also proposed to exempt certain projects from it. In particular, the Agency proposed not to apply the requirement to any project whose application for a PSD permit was complete before the requirement came into effect. *See* 44 FR 51928, 51954 (proposed § 52.21(j)(2)).

b. *Comments and final action on proposed transition provisions relating to BACT requirements:* In general, those commenting on the proposal to grandfather any project whose application was complete before the date of publication of this notice from the new BACT requirement favored such an exemption for at least those projects. Only two commenters, the same two who opposed the grandfather provision discussed above, opposed such an exemption for any project. They argued that EPA should adhere to the transitional rules that it established in the 1978 regulations, so that the new BACT requirements would apply to any project that fell or would fall within the coverage of those regulations, even to those which have already received a PSD permit.

EPA disagrees that it should or must adhere to the 1978 transitional rules in applying the new BACT requirements. As discussed above, the court in *Citizens to Save Spencer County* held that EPA has a "responsibility to harmonize the statutory provisions [sections 165(a) and 168] so as to implement the congressional mandate that new federal preconstruction review requirements be instituted promptly but with minimum economic dislocation." 600 F.2d at 851. Requiring a company which has already received a permit, or completed application for one, to amend project designs and permit applications to include BACT for pollutants to be emitted in "minor" amounts would hardly minimize economic dislocation. To the contrary, it would delay construction substantially in many cases. The benefits of that delay in those cases would probably fail to counterbalance its cost, since the new BACT requirements would apply only to pollutants this discrete group of projects would emit in "minor" amounts. Thus, applying the new BACT requirements retroactively to projects that already have a permit or a complete application would fail to give adequate expression to the economic considerations behind section 168.

Another commenter argued that the proposal did not go far enough, in that it would require companies which on the date of promulgation were just about to file a complete application to amend project designs and applications. The commenter urged EPA to apply the new BACT requirement only to projects whose applications were not complete within one year after the date of publication of this notice in the Federal Register. That alternative, however, would fail to give adequate expression to the environmental considerations behind section 165(a). EPA therefore has rejected it, too.

Instead, EPA has decided to adopt a provision like the proposal which exempts from the new BACT requirements any project whose application was complete before this notice appears in the Federal Register. *See* § 52.21(i)(9). EPA believes that the final provision reasonably accommodates the purposes and concerns behind sections 165(a) and 168.[6]

The final provision differs from the proposed provision somewhat. First, it appears in paragraph (i), instead of paragraph (j), the provision that sets forth the general BACT requirement. EPA has sought to gather each of the exemption provisions into paragraph (i). Second, the new exemption provision exempts an eligible project from the new BACT requirement entirely, but adds that the project is subject to the BACT requirements of the 1978 regulations, if they would otherwise have applied. The purpose of that structure is in part to assure that BACT would apply to a pollutant for which the project would be "major" under the 1978 regulations, but "minor" under the new Part 52 regulations due to the new concepts of "potential to emit" and "modification."

The final Part 52 regulations contain a definition of the term "complete" in reference to an application. Under that definition an application becomes "complete" when it contains all of the information necessary for application processing.

It should be noted, finally, that the date an application was complete will generally differ from the date on which the reviewing authority makes its completeness determination, since the filing of the last necessary piece of information will typically occur before the determination is made. When EPA makes a completeness determination, it will specify the date as of which the application was "complete." That date will be the date on which the last necessary piece of information was received. One of the provisions of the Consolidated Permit Regulations, 40 CFR 124.3(f) (discussed below), refers to the "effective date" of an application. Generally, the "effective date" of an application will follow the date it is "complete."

3. *Substantive Provisions Relating to Air Quality Analyses.*

a. *Proposed transition provisions:* Another new substantive requirement that EPA proposed in September was that an applicant provide an analysis of air quality in the area the project would affect for each pollutant regulated under the Act that the project would emit in "minor," but still significant, amounts. Under the 1978 regulations, an applicant had to provide such an analysis only for those pollutants for which the project would be "major" and for which EPA had set a national ambient air quality standard (NAAQS). The remaining new requirement was that, if the project would emit particulate matter or sulfur dioxide in a significant amount, the analysis focus on the extent to which ambient concentrations of the particular pollutant had consumed the applicable PSD increments.

In proposing the new requirements for air quality analyses, EPA also proposed to exempt certain projects from them. In particular, EPA proposed not to apply the new requirements to any project whose application was complete before the requirements came into effect. *See* 44 FR 51928, 51954 (proposed § 52.21(n)(1)(i)).

The 1978 Part 52 regulations contained a requirement that any air quality analysis for a pollutant for which a NAAQS exists ("criteria pollutant") must generally include monitoring data gathered over and relating to the year preceding the submission of a complete application. In September, EPA proposed a reformulation of that requirement. That requirement, however, when coupled with the new requirement for an analysis for each criteria pollutant emitted in "minor" amounts, could cause a prospective applicant substantial delay. As a result, EPA also proposed to require any applicant who does not file a complete application before the date of promulgation to gather monitoring data for any such "minor" pollutant only over the period (up to one year) from the date of promulgation and the date the applicant would file an otherwise complete application. *See id.* at 51928, 51954 (proposed § 52.21(n)(1)(iii)).

b. *Comments and final action on transition provisions relating to air quality analysis requirements:* Two

[6] Even if the conflict between sections 165(a) and 168 had not conferred on EPA the discretion to exempt projects with a complete application, EPA would have authority under section 301(a)(1) to exempt them, since applying the new BACT requirements to such projects would be unfair.

commenters argued that EPA should adhere to the transitional rules of the 1978 regulations with respect to the new requirements for air quality analyses. In their view, the monitoring requirements should apply in general to any "major" project for which certain permits were not obtained by March 1, 1978, and on which construction had not commenced by March 19, 1979. Certain other commenters objected to any application of the new monitoring requirements to a company which, although it had not filed a complete application by the date of promulgation, had nevertheless previously undertaken a program of monitoring the EPA or a state had approved.

Some additional comments were directed to the proposed phase-in provision. Those comments contended that a prospective applicant would find it impossible to satisfy that provision, since the purchase, installation, and "debugging" of new monitoring equipment, together with the analysis of any new data, would require at least several months. Many commenters did note that the draft of the revision of the monitoring guideline would allow three months for those tasks, but asserted that even three months would generally be insufficient. See U.S. EPA, *(Draft) Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)*, (October 1979). Some recommended an allowance of 2–5 months, others 6–9 months, and still others more than 10 months.

A number of commenters observed that the proposed regulatory language failed to embody the intent that the preamble had described. First, the proposed exemption for each "major" project whose application was complete before the date of promulgation focused only on the new requirement for an analyses for each pollutant that the project would emit in a "minor" amount. Hence, it would have failed to shield each such project from the new requirement for an analysis for each non-criteria pollutant that the project would emit in a "major" amount. Second, the provision that would have phased-in any new monitoring requirements focused only on projects whose applications were complete by the date of promulgation. Consequently, it specified no phase-in rules for projects whose applications were not complete by then, the very projects that EPA intended the rules to benefit.

Finally, one commenter pointed out an anomaly in the proposed phase-in provision: it focused only on the new requirement, in proposed § 52.21(n)(1)(iii), that an applicant provide monitoring data for any criteria pollutant that the project would emit in "minor" amounts. As a result, the proposed provision would have required a company with a project that is "major" under the new regulations, but was not under the 1978 regulations, to gather the full amount of monitoring data for each of its "major" pollutants, but none of its "minor" pollutants. But, since the monitoring requirements would have been new for the "major" pollutants, as well as the "minor" pollutants, such a company should have protection with respect to the "major" pollutants, too.

The final transition provisions relating to the new requirements for air quality analyses adhere to the spirit of the proposed provisions, but differ substantially in structure and articulation. One of the four final provisions, § 52.21(i)(9), exempts certain sources and modifications from the new requirements with respect to monitoring entirely. It provides that those requirements shall *not* apply to a source of modification that was subject to the 1978 Part 52 regulations, if its application becomes complete on or before the date this notice appears in the **Federal Register**. Instead, the air quality analysis requirements in the 1978 regulations apply to the source or modification.

Two of the three remaining provisions exempt certain other sources and modifications from the new monitoring requirements for criteria and non-criteria pollutants. One of those provisions, § 52.21(i)(10)(i), exempts a source or modification that would have been subject to the 1978 Part 52 regulations from those new monitoring requirements, if its application becomes complete with respect to the requirements of the new Part 52 regulations, other than the new monitoring requirements, on or before a date ten months from the date of promulgation. The provision adds the clarification that the monitoring requirements of the 1978 regulations apply instead to the source or modification. The other exemption provision, § 52.21(i)(10(ii), is similar. It exempts a source or modification that would not have been subject to the 1978 Part 52 regulations, if its application becomes complete with respect to the requirements of the New Part 52 regulations, other than those for monitoring, on or before a date ten months from the date this notice appears in the **Federal Register**.

The remaining provision, § 52.21(m)(1)(v), phases-in the monitoring requirements of new § 52.21(m)(1)(iv) to the extent that they place monitoring burdens on an applicant that the 1978 Part 52 regulations would not have imposed. Section (m)(1)(iv) provides in general that any required air quality analysis for a criteria pollutant must include monitoring data gathered over a period of at least one year. However, the new phase-in provision establishes the general rule that for certain applications the required monitoring data shall have been gathered over a period at least equal to the period from the date six months from the date of promulgation to the date the application becomes complete, except as to the monitoring requirements of the new Part 52 regulations. The applications to which this provision applies are those which become complete, except as to those monitoring requirements, between the date ten months from promulgation and the date eighteen months from promulgation. The new phase-in provision then states three exceptions to that general rule. First, an applicant with a project that would have been subject to the 1978 Part 52 regulations must provide at least whatever monitoring data the 1978 Part 52 regulations would have required the applicant to provide. Second, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a shorter period (not to be less than four months), the required data may be gathered over at least that shorter period. Finally, if the monitoring data would relate exclusively to ozone and would not have been required under the 1978 regulations, the Administrator may waive the otherwise applicable requirements of the phase-in provision to the extent that the applicant shows that the monitoring data would be unrepresentative of air quality over a full year.

The following example illustrates how the proposed phase-in provision works. A company proposes to construct a new plant that would emit sulfur dioxide and particulate matter. Under both the new Part 52 regulations and the 1978 regulations, the plant would be "major" for sulfur dioxide and "minor" for particulate matter. The emissions of particulate matter would not be *de minimis*. But for the phase-in provision, the new Part 52 regulations would require an application for a permit for the plant to contain a year's worth of monitoring data for both sulfur dioxide and particulate matter. (This assumes that the Administrator does not determine that a complete and adequate analysis could be accomplished with data gathered over a shorter period.)

The 1978 regulations would have required the application to contain a year's worth of data for just sulfur dioxide. The company submits an application which becomes complete, except with respect to monitoring, at the end of the fifteenth month after promulgation. Under the phase-in provision, the application must contain (1) a year's worth of monitoring data for sulfur dioxide and (2) nine months' worth of data for particulate matter.

The four final provisions embody EPA's response to the comments on the proposals. First, EPA has adopted the fundamental approach of the proposal, which was to apply the new monitoring requirements prospectively only. EPA has concluded that that approach reasonably accommodates the purposes and concerns of sections 165(a) and (e)(2), on the one hand, and section 168, on the other. In brief, the approach institutes the new requirements promptly, but with minimum economic dislocation. See *Citizens To Save Spencer County* v. *EPA*, 600 F.2d at 851. Full and immediate application of the new monitoring requirements would have caused substantial delays in the submission of complete applications and hence the issuance of permits, but provided little direct environmental benefit in return. As for applicants who undertook an approved program of monitoring before the date of this notice, the phase-in provision affords them adequate protection from delay, while at the same time generally demanding as much compliance with the new monitoring requirements as possible.[7] In short, EPA disagreed with the commenters who complained that the proposals would have instituted the new requirements too late, and with those who complained that the proposals would have instituted them too soon.

Second, with respect to the new monitoring requirements for criteria and non-criteria pollutants, EPA has established a grace period of ten months in the final grandfather provisions. It has done so because it agrees with the commenters who asserted that instituting a new monitoring program and analyzing the data it generates requires more than three months in many, if not most, circumstances. EPA has selected a grace period of ten months with respect to monitoring for both criteria and non-criteria pollutants, first, because six months is an estimate of the amount of time that would generally be needed to complete those tasks and, second, because there is little usefulness to less than four months of data for most pollutants.

The promulgated provisions cure the ambiguities in the proposal observed by some commenters. Section 52.21(i)(10) exempts an eligible project from the requirements relating, not only to any non-criteria pollutant that it would emit in "minor" amounts, but also to any non-criteria pollutant that it would emit in "major" amounts. In addition, the phase-in provisions now deal explicitly with projects whose applications were *not* complete by the applicable deadline. Finally, § 52.21(i)(10) protects not only projects that were subject to the 1978 regulations, but also projects that were not subject to them.

4. *Comments on the effective date of the substantive provisions.*

In proposing the new substantive provisions relating to BACT and air quality analyses the Agency stated that it intended to put those new provisions into effect immediately upon their promulgation. One commenter contended that EPA should put the new provisions into effect 30 days after promulgation, rather than immediately on the date of promulgation, so that "potential applicants [would have] sufficient lead time in planning modifications and new sources." With respect to the new provisions relating to air quality monitoring, the 10-month grace period and phase-in provision described above should satisfy the concerns of the commenter. With respect to the new BACT provisions, however, EPA disagrees. Prospective applicants have had ample warning of the new BACT provisions. The court in *Alabama Power* held in June of 1979 that Congress intended them to be imposed and in September 1979 EPA specified when it intended to impose them. Therefore, there is good cause to make these requirements immediately effective. The Administrative Procedure Act (APA), moreover, would not require a 30-day delay in implementation, since the provisions amount to legal interpretations. *See* APA section 4(d)(2), 5 U.S.C. section 553(d)(2).

5. *New Provisions Governing Procedure.*

EPA recently promulgated regulations aimed at consolidating and unifying various permit requirements and procedures. *See* 45 FR 33290 (May 19,1979) (the "Consolidated Permit Regulations"). Those new regulations contain provisions which will govern the processing of applications for permits under the Part 52 PSD regulations. Those provisions appear as 40 CFR 124.1–124.21 and 124.41–124.42, 45 FR 33485–93. Paragraph (r) of the 1978 Part 52 regulations has governed the processing of PSD permit applications under those 1978 regulations.

The Consolidated Permit Regulations contain a provision, section 124.21, which describes the transition from the procedures of paragraph (r) to the new consolidated permit procedures. It provides that those new procedures shall "apply to PSD proceedings in progress on July 18, 1980." 45 FR 33492. It adds that the requirements of sections 124.9 and 124.18, which would require the preparation of a formal administrative record, shall apply only to "PSD permits for which draft permits [*i.e.*, preliminary determinations] were prepared after the effective date of these regulations." *Id.*

In promulgating the new Part 52 regulations, EPA has adopted a new paragraph (q). It states that the new consolidated permit procedures govern the processing of PSD permit applications to the extent that they apply. It adds that the procedures of the 1978 Part 52 regulations continue to apply to the extent that the new procedures have not yet displaced them. In time, the new procedures will displace the old ones entirely.

B. Part 51 PSD Regulations

In September, EPA did not propose an amendments to the 1978 Part 51 regulations that paralleled the proposed Part 52 transition provisions. The Part 51 amendments that EPA did propose paralleled only the Part 52 provisions that would affect coverage and substance. The few comments that were submitted focused on this gap.

One commenter asked that EPA state in the Part 51 regulations that a state which has already adopted and obtained EPA approval of its own PSD program may, in conforming that program to the new Part 51 regulations, adopt a rescission provision like new § 52.21(w) into its plan. EPA believes that it is unnecessary to make such a statement in regulatory form. A state is free, in any event, to adopt such a provision and EPA would approve it.

Another commenter asked EPA to establish in the Part 51 regulations that a state with its own PSD program, in adopting new, more stringent requirements for BACT and air quality assessments in accordance with the new Part 51 regulations, may also adopt grandfather provisions that would apply the new requirements prospectively. In response, EPA had added a new section 51.24(a)(6) to the Part 51 regulations. The new section provides that PSD SIP revision may operate prospectively,

[7] Even if the conflict between sections 165(a), 165(e)(2), and 168 had not conferred on EPA the discretion to exempt certain projects from the new air quality analysis requirements, EPA would have had authority under section 301(a)(1) to exempt those projects, because application of those requirements would have been unfair.

thereby establishing that a state may adopt grandfather provisions of that sort. It adds, however, that the revision must take effect no later than the date of its approval. EPA has also added a new section 51.24(i)(9) to the Part 51 regulations. It provides that an approval revision to a state PSD program, which program EPA has already approved, may contain transition provisions that parallel the new Part 52 transition provisions. The new section also establishes that the proposed transition provisions must operate at least as stringently as their Part 52 counterpart would in the context of the state PSD program.

Finally, a third commenter urged EPA to require a state with its own PSD program to delete these aspects of the plan that go beyond the requirements of the new Part 51 regulations within nine months after the date of promulgation of those new regulations, unless the state within that period of time submits "to EPA written acknowledgment that it is not required by federal law to include such provisions in its state plan, but has nevertheless elected to do so under state law pursuant to section 116 of the Act." The commenter feared that, absent such a requirement, inertia and lack of resources might prevent some states from deleting the provisions in question. Such a requirement, however, would interfere unnecessarily in the affairs of a state. EPA, moreover, doubts that it would have the authority in any event to repeal the more stringent aspects of a state plan simply because the state failed to say by a certain time that it wanted to retain those aspects. EPA therefore has not promulgated the requirement sought by the commenter.

After examining the Part 51 regulations in response to those comments, EPA has decided to add two new provisions. The first, section 51.24(a)(6), merely states in regulatory form what section 406(d)(2)(B) of the Clean Air Act Amendments of 1977 already states: any PSD SIP revision required by the new Part 51 regulations must be adopted and submitted within nine months of the date this notice appears in the **Federal Register**. The second provision, § 51.24(a)(6)(ii), establishes explicitly that any PSD SIP revision must contain provisions which describe when and as to what sources and modifications the revision is to take effect. The purpose of that requirement is merely to minimize confusion and uncertainty during the transition from any old to new PSD SIP requirements.

C. Offset Ruling

The amendments to the Offset Ruling which EPA is announcing in this notice expand its coverage, just as the amendments to the Part 52 PSD regulations expand its coverage. In EPA's view, the expansion of the coverage of the Offset Ruling should operate prospectively only. Hence, it has inserted into the Ruling a grandfather provision that parallels the relevant PSD grandfather provision. It provides that the Ruling does not apply to any source or modification that was not subject to the version of the Ruling in effect prior to the date this notice appears in the **Federal Register**, if all necessary SIP permits were obtained for the source or modification by that date and if construction commences within 18 months of that date.

D. Part 51 Nonattainment Regulations

Pursuant to section 406(d)(2)(B) of the Clean Air Act Amendments of 1977, states will have nine months after the date of this notice appears in the **Federal Register** in which to adopt and submit any new definitions and other regulatory provisions required by new 40 CFR 51.18(j). States need not adopt verbatim the definitions in section 51.18(j)(1), but they must demonstrate that any different definitions they retain or adopt have the effect of being at least as stringent as those set out in § 51.18(j)(1). If a state plan currently includes definitions or regulatory provisions which are more stringent than the nonattainment definitions and other provisions contained in these final rules, the state has the choice of retaining its current regulations or of revising them so as to conform to EPA's rules. If a state does not submit any necessary revisions to its plan within nine months after the date this notice appears in the **Federal Register**, the construction moratorium will go into effect 15 months after this date in all nonattainment areas in that state. The additional 6 months is consistent with the review period allotted for Part D submitted under section 110(a)(2)(I) and 129(c) of Pub. L. 95-95.

EPA received only one comment on transitional requirements for § 51.18(j). This commenter requested that EPA allow states which have already adopted NSR regulations pursuant to section 173 of the Act be permitted to adopt a rescission provision like that of § 52.21(w). EPA believes that to make such a statement in regulatory form is unnecessary. A state is free to adopt such a provision, and EPA will approve it, provided that the state's NSR program meets the requirements of section 173 and that permit rescission will not interfere with reasonable further progress or attainment of ambient air quality standards.

E. Construction Moratorium

The amendments to the construction moratorium expand its coverage in some ways, too. Hence, EPA has promulgated a grandfather provision patterned after the relevant PSD and Offset Ruling provisions. It appears as § 52.24(g).

F. Pending SIP Revisions

By the date this notice appears in the **Federal Register**, EPA will not have taken final action on many PSD and nonattainment SIP revisions that states have already submitted. EPA intends to review those pending revisions under the requirements that applied to them before the date of promulgation. To wait until a state had revised its revisions to bring them into line with the new PSD and nonattainment requirements would cause the state and its industry to suffer a heavy and undue burden, particularly in those cases where approval of a Part D plan is needed to lift the construction moratorium.

G. Effective Date of the Nonattainment Provisions

EPA has made all of the new nonattainment provisions announced here effective immediately upon their promulgation. EPA finds that it has "good cause" within the meaning of the relevant provisions of the Administrative Procedure Act to do so. First, the new provisions in the main provide relief from pre-existing regulatory burdens. Second, the decision in *Alabama Power* and the September 1979 proposal provided ample warning of the new changes. Finally, it is important for planning and management by EPA, the states and industry that these new provisions come into effect as soon as possible.

H. Miscellaneous

Under the amendments announced in this notice, each set of PSD and nonattainment regulations uses the phrase "this section" at some points and phrases such as "40 CFR 52.21" at other points. EPA intends "this section," when used in a particular set of regulations to refer only to the version of the regulations which has resulted from the amendments announced here. For example, the phrase "this section" in new § 52.21(i)(1)(i) refers only to the Part 52 PSD regulations as newly constituted. EPA intends phrases such as "40 CFR 52.21" to refer to any version of the particular regulations which has appeared or is to appear at the particular location in the Code of Federal Regulations. For example, "40 CFR 52.21" refers to each version of the Part 52 PSD regulations that has ever

existed, including the version that has resulted from the amendments announced here.

V. Potential to Emit

The preconstruction review requirements of section 165 of the Act apply to any "major emitting facility." 42 U.S.C. 7475. Pursuant to section 169(1), that term includes any stationary source which emits or has the "potential to emit" 100 tons per year or more of any pollutant, for sources included in one of 28 specified source categories, or 250 tons per year or more of any pollutant for any other type of source. 42 U.S.C. 7479(1).

A. Control Equipment

Obviously, many more sources would be affected if the term "potential to emit" referred to the amount of pollution that a source would emit without controls than if it took the operation of control equipment into account. In the PSD regulations promulgated on June 19, 1978, EPA took the former approach and defined "potential to emit" as "the capability at maximum capacity to emit a pollutant in the absence of air pollution control equipment." 40 CFR 51.24(b)(3), 52.21(b)(3) (1979). This approach was rejected by the *Alabama Power* decision which held that Congress intended that, in determining a facility's potential to emit, EPA "must look to the facility's 'design capacity' a concept which not only includes a facility's maximum productive capacity (a criterion employed by EPA) but also takes into account the anticipated functioning of the air pollution control equipment designed into the facility." 13 ERC 1993, 2003.

In response to the court's decision, EPA proposed, on September 5, 1979, a revised definition under which the application of control equipment would be taken into account in computing potential emissions. That approach, which was very strongly supported by public comments, is now being promulgated. 40 CFR 51.24(b)(5) and 52.21(b)(5).

The proposal noted that EPA will assume that a facility's air pollution control equipment will function in the manner reasonably anticipated. In this promulgation the Administrator is implementing the proposed approach by requiring that operation of control equipment be an enforceable requirement. In other words, a company may receive credit for the application of control equipment only to the extent that the resulting reduction in emissions is federally enforceable (see below). This provision is necessary, as a practical matter, to ensure that sources will perform the proper operation and maintenance for the control equipment. Thus, a source installing control equipment that would reduce emissions more than that required by generally applicable emissions limitations cannot receive credit for the additional increment of pollution reduction, unless it is federally enforceable. The definition of "potential to emit" is being modified appropriately.

Under the definition being promulgated, the potential to emit of existing sources with respect to the treatment of enforceable in-place control equipment shall be defined in the same fashion as discussed above for new sources. This responds to commenters who complained of this discrepancy in the September 5 proposal. Accordingly, potential to emit for all sources means the ability at maximum design capacity to emit air pollution, taking into account any *in-place* control equipment. Design capacity, and thus potential to emit, may be further limited if control equipment better than that normally required by the applicable SIP is installed and a correspondingly more stringent level of emissions control is included as an enforceable permit conditon. Finally, it should be noted that the potential to emit of a stationary source in today's rule is of primary importance in defining when a source would be major; it is not generally used in determining increment consumption or the baseline for assessing emission increases and decreases at a source (*see* Modification).

B. Continuous Operation

Under the existing definition of "potential to emit," a source can avoid PSD review if it binds itself, in a federally enforceable permit, to sufficiently limited hours of operation. 40 CFR 51.24(v)(5), 52.21(b)(5) (1979). In the September 5, 1979 proposal, EPA proposed to delete the clause which allows such adjustments and to presume continuous (24 hours per day, 365 days per year) operation. Consistent with that change, EPA also proposed to delete, from the same regulation, the words "or amount"; those words at present allow permit limitations on amount of materials combusted, processed, or stored to be considered in computing potential to emit. In making this proposal, the Administrator also requested comment on the need to adjust the assumption of continuous operation, in the case of sources which are physically incapable of such operation.

Many commenters (169 of 173) have strongly criticized this proposal, the most frequent response being that few sources operate constantly, and most cannot do so. These commenters also advised the Agency of certain benefits which would accrue from allowance of permit conditions in computing potential to emit. For example, a benefit noted is that such an approach would better relate the PSD permit applicability of new sources to the offset potential of existing sources, and to how the increment would be consumed. This approach was also claimed to be consistent with EPA's stated goal of developing PSD requirements which will fit into state programs in such a way as to minimize disruption of those programs and promote PSD SIP development by the states. Additionally, insignificant reviews would be minimized and PSD applicability would be more reflective of emissions actually produced by the source.

There was some comment in support of the proposal. A state environmental agency noted that emissions limits calculated from less than continuous operation are less easily enforceable than those which are based on continuous opertion. An environmental group supported the proposal on the grounds that it is consistent with the interpretation of "full design capacity," that it would be appropriately technology-forcing, and that it is necessary to protect the short term increment. These concerns are addressed below.

The court based its definition of "potential to emit" on the source's full design capacity. *Id.* at 2003. The June opinion in *Alabama Power* did not directly address the acceptability of legal limitations on operation but did stress design capacity in the sense of physical and technological, as opposed to operational, limitations. However, in the final opinion, released on December 14, 1979, the court stated:

> The design capacity of a facility rarely contemplates uninterrupted operation 24 hours per day, 365 days per year. Projected downtime for repairs and maintenance *or other factors* may reduce the hours of operation that are appropriately considered in the calculation of a facility's "potential to emit." (*Id.* at 2005, n. 73.) (Emphasis added)

EPA interprets this language as not precluding permit conditions, that are federally enforceable under the applicable SIP, from circumscribing a source's potential to emit. In view of the above, the Agency believes it has discretion to adopt the most reasonable approach to this issue and has, therefore, reconsidered its proposal. Today's regulations recognize the ability of all federally enforceable limitations to constrain the potential to emit of a stationary source.

The Administrator believes that the policy concerning "enforceable permit conditions" is responsive to most of the concerns raised by commenters who were critical of EPA's proposal. New sources are now allowed to avoid NSR for PSD and nonattainment areas by limiting their type or amount of operation. Moreover, potential to emit is now defined in the same way for new and existing stationary sources. The use of certain permit conditions also addresses the concerns raised regarding physical incapability and peak load or standby units. This is, source owners or operators can now agree to source-specific permit conditions to limit their operation as appropriate. Such conditions can make infrequent operation and other physically limiting factors outside the design capacity of an emissions unit legally enforceable and can thereby limit the applicability of NSR.

The final policy concerning enforceable permit conditions has also taken in account the concerns of those favoring the proposal. One commenter noted that limited operation conditions would require greater enforcement attention. The Administrator agrees, but he believes that such conditions can be reasonably enforced. Another commenter also noted the need to minimize any air quality threats to short term increments by sources with intermittent operation but high short term rates of emission. No commenter presented a solution to this problem. EPA believes, however, that short term emissions limitations can be computed to address threats to short term increments, should any problems actually arise. It would be the responsibility of the reviewing authority to identify, in periodic evaluations, any sources causing such problems and apply appropriate limitations on their emissions. The Administrator will consider rulemaking to develop short term applicability thresholds, if necessary, after a reasonable amount of review experience has been developed.

Finally, as a result of today's policy, a potential problem exists concerning the future relaxation of a preconstruction permit that previously caused a proposed stationary source to enjoy minor rather than major status. For example, a source might evade NSR through agreement to unrealistically stringent operating limitations in its permit, and later obtain a relaxation of the condition. The Agency believes that the problem can be dealt with by 40 CFR 52.21(r)(4), entitled "Source Obligation." That paragraph provides that any owner or operator of a source, who would receive a relaxation of a permit condition that had enabled avoidance of NSR, would then become subject to review for all units subject to the original permit, as if they were new sources. In other words, if operational limitations are to be considered as an aspect of a source's design, it is reasonable that the permit accurately incorporate that design. If such operation is changed, the permit, and concomitant obligations, should be correspondingly changed.

C. Additional Guidance

Fugitive emissions under today's regulations are applicable in defining potential to emit. (*See* Fugitive Emissions.) However, like the proposal, such emissions do not count in assessing permit applicability unless a specified type of source category is involved. To accomplish this a specific exemption has been added to the final regulations by which fugitive emissions will be included in determining potential to emit only for specified source categories.

The definition of "potential to emit" is important not only to PSD preconstruction review, but also to NSR under the Offset Ruling (44 FR 3274), the statutory requirements for nonattainment areas, and the restrictions on construction in sections 110(a)(2)(I) and 173(4) of the Act. EPA is promulgating for each of those nonattainment programs the same definition of "potential to emit" that it is promulgating for the PSD program, as well as a provision like § 52.21(r)(4). EPA also intends this definition to be implemented for those programs in the same way as for PSD.

EPA has traditionally distinguished, for the purpose of NSR, between the direct emissions of a source and its "secondary emissions." (*See* Additional Issues.) In revising the Offset Ruling in January 1979 the Agency added a definition of "secondary emissions" and a provision describing for what purposes and under what circumstances those emissions are to be taken into account. *See* 44 FR 3281, 3283–84 (January 16, 1979). EPA is now adding that concept to the PSD regulations and to the nonattainment provisions relating to NSR and the restrictions on construction. For each of those sets of provisions "secondary emissions" are to be excluded in determining whether the regulations apply to a source (*i.e.*, whether a source or modification is "major"). Similarly, the control technology requirements of BACT and lowest achievable emission rate (LAER) do not apply to secondary emissions. How the Agency would treat those emissions for other purposes, including PSD air quality impact analysis, is described in Additional Issues.

VI. 50-Ton Exemption

Under the 1978 PSD regulations, stationary sources or modifications with allowable emissions of less than 50 tons per year, 1000 pounds per day, or 100 pounds per hour were in general exempted from the BACT and ambient air quality analysis PSD requirements. 40 CFR 51.24(j)(2), (k), and 52.21(j)(2), (k) (1979). In its preliminary *per curiam* decision the court thought that its ruling on "potential to emit" made a ruling on the 50-ton exemption "academic," since no 50-ton source would ever be major if "potential to emit" referred to controlled emissions. 13 ERC at 1228–29. Nevertheless, it remanded the exemption to the Agency for reconsideration and noted that the Agency had exceeded its authority in establishing the exemption. In response, EPA proposed to delete the provisions which embodied the exemption, and to delete parallel provisions in the Offset Ruling. EPA, however, proposed adding to the PSD regulations a 50-ton exemption for certain modifications. The proposed exemption tracked section 165(b) of the Act closely, but not exactly. Essentially it provided that a source qualifying for the exemption would face a limited air quality review for SO_2 and PM. Use of the exemption would be restricted to modifications, at a plant existing as of August 7, 1977, entailing emissions increases of 50 tons or less of any pollutant after application of BACT and which would impact no Class I area or interfere with the attainment of PM or SO_2 standards. All net emission changes since August 7, 1977 would be aggregated in applying the exemption.

All of the seventeen commenters who focused on the proposed provision expressed general agreement with this approach, but some commenters stated that the exemption should be broader. For example, four commenters wanted an additional 50-ton exemption after each full review. Five commenters requested a special, more lenient, review for pollutants whose emissions rates fall between 50 tons per year and the *de minimis* level in those cases where the exemption would not apply. The Administrator finds no grounds for providing additional exemptions after each review. Similarly, there is no justification or authority under section 165(b) for a special limited review for emissions increases falling between *de minimis* amounts and the 50-ton level. A few commenters suggested that other eligibility values than 50 tons be used. EPA responds that section 165 of the Act

mandates the 50-ton figure, but that much of these commenters' concerns are dealt with by the *de minimis* provisions being promulgated today. Two other commenters requested that the exemption be governed by net emissions increases. Today's regulations provide that review is applicable to net emissions increases, thus addressing the concerns of the two commenters cited above. With this exception, and the two noted below, the 50-ton exemption is being promulgated as proposed.

Some commenters pointed out that EPA's proposed 50-ton exemption clause was more limted in its application than the Clean Air Act language of section 165(b), in that the September 5 proposal contained additional consideration of Class I area impacts (*e.g.*, 44 FR 51949, 40 CFR 51.24(k)(2)(i)). EPA agrees with these commenters and has eliminated that portion of the 50-ton exemption language dealing with Class I areas. *See* 40 CFR 51.24(i)(7) and 52.21(i)(7).

The 50-ton exemption contained in the Act made those sources existing as of August 7, 1977, eligible for the exemption; the same applicability date was proposed in September 1979 for this revised exemption. The *Alabama Power* final opinion suggested that EPA had authority to conform the eligibility date for the section 165(b) exemption to the "effective date" of the preconstruction permit requirements of the 1978 regulations, i.e., March 1, 1978. In the January 30, 1980 Federal Register notice EPA sought comment on changing the eligibility date and on whether March 1, 1978 would be the appropriate choice.

Twenty-four commenters addressed the issue of the eligibility date. Nineteen of these favored a date of March 1 or 19, 1978. Four wanted the date to be that of the final promulgation of these regulations. One commenter disagreed with the date change because it considers the exemption itself to be unauthorized; however, the Act clearly provides for the exemption, as explained elsewhere in this section. One industrial group alleged that the date of promulgation would be the proper eligibility date for the specific case of fugitive emissions, in that fugitives were not regulated as of March 1, 1978. This is apparently a reference to the fact that rulemaking relative to potential to emit (*see* Potential To Emit) had not yet been performed. In fact, though, fugitive emissions were covered by the 1978 regulations and the calculation of potential to emit does not change that circumstance. The commenters preferring March 19 to March 1 referred to a statement in *Alabama Power* that March 19, 1978 is the "effective date" of the regulations. 13 ERC at 2006, n.79. The "effective date" of those regulations is, however, March 1, 1978. *See Citizens to Preserve Spencer County* v. *EPA*, 12 ERC 1961, 1978; and Preamble to 1978 Regulations, 43 FR 26380, 26390. Concerning the comments favoring the date of this promulgation as the eligibility date, the Administrator notes that section 165(b) of the Act limits eligibility for the 50-ton exemption to those sources in existence on the date of enactment of the 1977 Admendments to the Act. For the reasons noted in the *Alabama Power* decision, EPA has authority to extend eligibility to March 1, 1978. However, the Agency cannot extend this deadline to today's promulgation. For these reasons March 1, 1978 is now promulgated as the eligibility date for the 50-ton exemption.

VII. Fugitive Emissions

For PSD determinations prior to the *Alabama Power* decision, EPA considered *all* reasonably quantifiable emissions of a pollutant—including both point emissions (*e.g.*, from a stack or chimney) and fugitive emissions—on the ground that the emissions deteriorate air quality regardless of how they emanate. This practice applied to calculations of a source's emissions and potential emissions of a given pollutant both: (1) for the threshold determination under section 169(1) of whether the source was a "major emitting facility" subject to section 165, and (2) for the permitting requirements of section 165 itself.

The *Alabama Power* court upheld EPA's practice for the latter purpose, and confirmed that:

> The terms of section 165, which detail the preconstruction review and permit requirements for each new or modified "major emitting facility" apply with equal force to fugitive emissions and emissions from industrial point sources.
>
> * * * * *
>
> EPA is correct that a major emitting facility is subject to the requirements of section 165 for each pollutant it emits irrespective of the manner in which it is emitted. [13 ERC at 2016–2017.]

However, as to the first practice, the court held that section 169(1) is controlled by the rulemaking provision of section 302(j), and that fugitive emissions of a given pollutant may be included in the threshold calculation under section 169(1) only if the Administrator first determines, by rule, that they are to be included.

Accordingly, as part of the September 5, 1979 rulemaking proposal, the Administrator identified 27 categories of stationary sources for which he proposed to include fugitive emissions in threshold calculations of "major emitting facility" status for purposes of both section 165 and new source review regulations. Numerous commenters responded that the Administrator's proposal did not constitute "adequate" rulemaking, and that fugitive emissions could not be included in threshold calculations unless the rulemaking also established, on an industry-by-industry basis, methods for quantification of fugitive emissions and for analysis of their impacts on air quality, and included the identification of effective techniques for their control. EPA has considered these comments, but believes that Congress intended the rulemaking provision of section 302(j) to serve a much simpler and narrower purpose.

As the court itself noted, "[t]he legislative history of this rulemaking provision is sparse," and it is therefore particularly difficult to discern Congress' motivation for including it. 13 ERC at 2017. In general, section 302(j) sets out the criteria for determining whether a source is "major" and hence subject to the stringent requirements of certain key provisions of the Act. Congress clearly intended such determinations to always include point emissions, the type most commonly associated with major polluters. It also expressed its affirmative intent *not* to exclude "non-point" or "fugitive" emissions from those determinations:

> [T]he "major stationary source" definition is clarified to indicate the inclusion of major sources of fugitive emissions (last year's bill was unclear in this respect) * * *.[H.R. Rep. 95–294, 95th Cong. 1st Sess. 4 (1977).]

Rather than include fugitive emissions across-the-board, however, Congress left it to the Administrator to determine for which particular categories of sources fugitive emissions will be included in threshold calculations.

EPA therefore believes that the purpose of the rulemaking under section 302(j) is to afford members of affected categories of sources an opportunity to comment on the Administrator's determination to include fugitive emissions in the threshold calculation, and to allow them to present factual or policy arguments in support of claims that it would *not* be appropriate to do so. Although many such presentations will be technically oriented, EPA does not agree that section 302(j) requires the formal promulgation of measurement, modeling or control techniques or guidelines, because the fundamental decision which the Administrator is making under section 302(j) is *whether* fugitive emissions should be included in threshold calculations.

EPA finds support for this interpretation of section 302(j) in the fact that section 165 does *not* contain any rulemaking provision governing the *substantive* regulation of fugitive emissions. As explained earlier, the *Alabama Power* court confirmed that once a source is determined to be a major emitting facility under section 169(1), the substantive preconstruction review and permitting requirements of section 165 "apply with equal force to fugitive emissions and emissions from industrial point sources." In other words, even if fugitive emissions remain excluded from threshold calculations, section 165 requires that fugitive emissions be taken into account in determinations of whether NAAQS or allowable increments will be violated (section 165(a)(3)) and that fugitive emissions be subjected to BACT requirements (section 165(a)(4)). But these substantive provisions do *not* require EPA's prior promulgation of technical rules governing measurement, analysis or control such as those which the commenters suggest are necessary under section 302(j). Since the determination to include fugitive emissions in threshold applicability calculations is discretionary under sections 302(j) and 169(1), while the substantive regulation of fugitive emissions from all major emitting facilities is mandatory under section 165, EPA does not believe that the rulemaking provision of section 302(j) was intended to require the promulgation of such technical guidelines or regulations.

EPA therefore concludes that the rulemaking which it conducted was "adequate" under section 302(j) since affected sources were afforded the opportunity to comment upon the proposed inclusion of fugitive emissions in their threshold calculations. EPA's responses to more specific comments are set out below. Several commenters objected that the first 28 specific categories of sources identified in the proposal (as sources whose fugitive emissions would be taken into account in threshold calculations) were virtually identical to the 28 categories of sources identified in section 169(1) as sources with threshold tonnages of 100 tons per year (rather than 250 tons per year) for determinations of "major emitting facility" status.[8] The commenters complained that by merely copying the 28 sources without any other supporting rationale, EPA failed to conduct proper rulemaking.

Although it is true that the two lists are virtually identical, it is not true that EPA failed to conduct proper rulemaking. To the contrary, the Administrator recognized that in specifically identifying 28 categories of sources in section 169(1), "Congress' intention was to identify facilities which, due to their size, are financially able to bear the substantial regulatory costs imposed by the PSD provisions and which, as a group, are primarily responsible for emission of the deleterious pollutants that befoul our nation's air." 13 ERC at 2003. In light of that intent, the Administrator initially determined that as a matter of policy, it would be appropriate to count *all* emissions—including fugitive emissions—in threshold calculations of applicability for those 28 categories. The proposal reflected that determination as well as the Administrator's observation that, because those sources have traditionally been considered the major polluters in the country, EPA's experience in quantifying fugitive emissions from them is, in general, greater than its experience in doing so for other sources.[9]

Source Category and Reference
Primary zinc smelters
Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions—March 1977 (EPA-450/3-77-010)
Portland cement plants
(EPA-450/3-77-010)
Iron and steel mill plants
Particulate Emission Factors Applicable to Iron and Steel Industry (EPA-450/4-79-028) (EPA-450/3-77-010)
Primary aluminum ore reduction plants
(EPA-450/3-77-010)
Primary copper smelters
(EPA-450/3-77-010)
Petroleum refineries
Compilation of Air Pollutant Emission Factors (AP-42)
Lime plants
(NSPS) (AP-42) (EPA-450/3-77-010)
Phosphate rock processing plants
(EPA-450/3-77-010)
Coke oven batteries
(EPA-450/4-79-028)
Carbon black plants
(AP-42)
Primary lead smelters
(AP-42) (EPA-450/3-77-010)
Sintering plants
(See iron and steel mill plants)
Fossil fuel-fired boilers
(See Fossil fuel-fired steam electric plants)
Petroleum storage and transfer units
(AP-42)
Fossil fuel-fired steam electric plants
(EPA-450/3-77-010)

Several commenters pointed out, however, that the two lists were not identical insofar as certain restrictions or limitations for six categories of sources in the section 169(1) list were not reflected in the proposed section 302(j) list. Specifically, the section 169(1) list includes only the following (the italicized portions were omitted from the proposal): fossil-fuel fired steam electric plants *of more than two-hundred-and-fifty million British thermal units per hour heat input;* coal cleaning plants (*thermal dryers*); municipal incinerators *capable of charging more than two-hundred-and-fifty tons of refuse per day;* carbon black plants (*furnace process*); fossil-fuel boilers *of more than two-hundred-and-fifty million British thermal units per hour heat input;* and petroleum storage and transfer facilities *with a capacity exceeding three-hundred-thousand barrels.* These discrepancies are the result of an inadvertent administrative error, since EPA intended to identify in the proposed section 302(j) list the same categories of sources identified by Congress in the section 169(1) list. Accordingly, the final list promulgated today reflects the qualifying descriptions specified above for the six categories of sources. Several commenters objected to the last category on the list of sources for which the Administrator proposed to include fugitive emissions in threshold calculations—namely, "any other stationary source category which, at the time of the applicability determination, is being regulated under section 111 or 112 of the Act." Section 111 concerns the establishment of standards of performance for new stationary sources (new source performance standards or NSPS) and section 112 concerns the establishment of national emissions standards for hazardous air pollutants (NESHAP). The commenters argued that the focus of these provisions is on emissions controls rather than on ambient air quality, and that there is therefore no logical link to support the automatic inclusion of fugitive emissions from a source for PSD threshold calculation purposes simply because the source is being regulated under section 111 or section 112. EPA disagrees with some of the commenters' assumptions and characterizations of NSPS and NESHAP regulation, but concludes for other reasons that the last category should be revised to apply only to sources which are being regulated under section 111 or section 112 as of the effective date of the amended PSD and NSR regulations.

[8] The apparent discrepancy in the number of categories (i.e., 26 versus 28) is explained by the fact that the September 5, 1979 proposal listed hydrofluoric, sulfuric and nitric acid plants together in a single subheading.

[9] For example, EPA has previously published fugitive emissions data for many of the identified categories of sources:

The commenters contend that since an NSPS under section 111 merely reflects, for a category of sources, an emissions limitation which is achievable through the best system of continuous emissions reduction which "the Administrator determines has been adequately demonstrated," the establishment of an NSPS for a source is unrelated to the ambient air quality considerations which are at the heart of PSD review. What the commenters overlook, however, is that under section 111(b)(1)(B), NSPS are only promulgated for categories of stationary sources which have been included in a list under section 111(b)(1)(A); and section 111(b)(1)(A) directs the Administrator to "include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." In other words, although the NSPS itself may be based on technological considerations, the decision to develop the NSPS is clearly based on ambient air quality concerns. Moreover, under section 112, ambient air quality is clearly a compelling concern because a hazardous air pollutant to which a NESHAP will apply is one "which in the judgment of the Administrator causes, or contributes to, air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness."

In short, categories of sources are regulated under section 111 or section 112 on the basis of determinations by the Administrator that their emissions seriously and adversely impact ambient air quality, and the Administrator therefore determined that it would be appropriate to include their fugitive emissions in their threshold calculations for purposes of PSD and NSR review and regulation. That basic policy determination is being finalized today.

At the same time, however, EPA believes that the comments about "automatic" inclusion of categories of sources which are not now regulated under section 111 or section 112, but which may be regulated thereunder at some point in the future, raise valid concerns. Although EPA believes that the same basic policy considerations would support the inclusion of fugitive emissions for such categories of sources, EPA recognizes that unless a source had affirmative notice during this rulemaking that it will be regulated in the future under section 111 or section 112, it will not really have been afforded a meaningful opportunity to comment on the proposed inclusion of its fugitive emissions in its threshold calculations. Accordingly, EPA has determined to limit the scope of the last category on the proposed list to sources which are being regulated under section 111 or section 112 as of the effective date of these amended PSD and NSR regulations. At the time of any future rulemaking under section 111 or section 112 proposing to regulate additional categories of sources, EPA will conduct parallel section 302(j) rulemaking concerning the proposed inclusion of fugitive emissions in threshold calculations. On the issue of the appropriateness of including fugitive emissions in threshold calculations for particular categories of sources, the basic objection expressed by most commenters was that fugitive emissions data were either unavailable or inadequate, and that it would therefore be inappropriate to include fugitive emissions in threshold calculations for a particular category.

In response, EPA notes that such concerns should and will be addressed in the context of particular applicability determinations, but that they have not changed the basic policy decision made by the Administrator under section 302(j). As explained earlier, fugitive emissions *must* be taken into account under section 165 in determining the impact on ambient air quality of a proposed new source and the BACT requirements which will apply to it, even if there are no existing fugitive emissions data, or if the available data are crude. Obviously, the nature and extent of the available data and technologies are important factors in determining how fugitive emissions should be taken into account and how they should be regulated under the review and permitting process of section 165; but those factors will not avoid or eliminate the consideration of fugitive emissions under that process. Similarly, although the issue of quantification may be relevant to particular applicability determinations, EPA does not believe that that issue alone is critical in determining whether, as a general policy matter, it is appropriate to include fugitive emissions in threshold calculations for a particular category of sources.

EPA emphasizes, however, that fugitive emissions from a source in one of the listed categories will only be included in threshold calculations "to the extent quantifiable." EPA's intent was and is to provide sources the flexibility to explore with the reviewing authority in the context of a particular applicability determination, issues of quantification which might be peculiar to an individual source. (Of course, fugitive emissions will not have to be quantified for threshold purposes if the source would qualify as a "major emitting facility" on the basis of point emissions alone, a situation which EPA believes will occur more often than not.) As indicated above, EPA has in the past published data and other information relating to the quantification of fugitive emissions for various categories of sources and, as some commenters noted, additional data and information are currently under development. EPA considers these publications concerning quantification of fugitive emissions as guidance to be used as the starting point for analysis, not as methodology or data which must be rigidly adhered to in all circumstances.

EPA encourages the development of more sophisticated or precise methods or models for quantification of fugitive emissions, and will accept any estimate of a source's fugitive emissions if the source can support the accuracy and reliability of the methodology which it has developed or employed. In situations where there are no published emissions factors or other fugitive emissions data for a particular category of sources, EPA will consider quantification estimates developed by a source which have any reasonable and rational basis, including estimates based on the transfer of technology or based on principles of material balance. Moreover, if a source satisfactorily demonstrates that all such methodologies are inappropriate in its circumstances and that there is absolutely no basis for reasonably estimating its fugitive emissions, EPA would be willing to discount fugitive emissions in the threshold calculation for that individual source.

In short, sources will have an opportunity to discuss the appropriateness and reasonableness of fugitive emissions estimates for purposes of both the threshold calculation, as well as the requirements of section 165. EPA is therefore finalizing today the proposed list of categories of sources whose fugitive emissions will be included in threshold calculations. EPA has considered comments with respect to the proposed definition of "fugitive emissions," and has determined that one change is appropriate. Instead of defining fugitive emissions as "those emission which *do not* pass through a stack, chimney, vent, or other functionally equivalent opening," EPA believes that the term should apply to "those emissions which *could not reasonably pass* through a stack, chimney, vent or other

functionally equivalent opening." This change will ensure that sources will not discharge as fugitive emissions those emissions which would ordinarily be collected and discharged through stacks or other functionally equivalent openings, and will eliminate disincentives for the construction of ductwork and stacks for the collection of emissions. Emissions which could reasonably pass through a stack, chimney, vent, or other functionally equivalent opening will be treated the same as all other point emissions for threshold calculation purposes.

In addition, in light of EPA's action today deleting the fugitive dust exemption [*see* Fugitive Dust Exemption], EPA is finalizing the proposed deletion of the existing definition of "fugitive dust" at 40 CFR 51.24(b)(6) and 52.21(b)(6) (1979).

VIII. Fugitive Dust Exemption

The 1978 PSD regulations provided that "fugitive dust" from a major stationary source or major modification be excluded from air quality impact assessment, 40 CFR 51.24(k)(5), 52.21(k)(5)(1979). Because of its decision regarding inclusion of fugitive emissions in threshold calculations, and because it questioned EPA's authority to establish the exemption in the manner in which it did, the court in *Alabama Power* vacated EPA's generalized exemption for fugitive dust and remanded it to the Agency for further consideration. 13 ERC at 1231 and 13 ERC at 2017.

In response to the court's opinion, EPA proposed deletion of the fugitive dust exemption. It also proposed to delete a parallel provision in the Offset Ruling (44 FR 3274). The majority of the public commenters directly opposed this proposal. The primary reasons were that fugitive dust allegedly has little impact on health and that techniques of evaluating its air quality impacts are unreliable.

As indicated above, the *Alabama Power* court vacated EPA's partial exemption of fugitive dust from the requirements of section 165 because the exemption was premised on the erroneous assumption that "the statute of its own momentum subjects major sources of fugitive emissions to PSD preconstruction review and permit requirements" 13 ERC at 2017. However, the court also expressed serious doubt that EPA had the statutory authority to establish such an exemption by regulation, because (1) section 165 does not distinguish between fugitive emissions and point emissions, but applies "with equal force" to both types of emissions, 13 ERC at 2016, and (2) in the absence of explicit statutory exemption authority, EPA's "general" exemption authority is narrow in reach. 13 ERC at 2005–2010.

The court did outline, though, a mechanism which it indicated is available under the statutory scheme for accomplishing the objective of partially exempting fugitive dust emitted by major emitting facilities from the requirements of section 165. That approach would involve defining the pollutant "particulate matter" "to exclude particulates of a size or composition determined not to present substantial health or welfare concerns," 13 ERC at 2018, n. 134, and then regulating such "excluded particulates" under section 111. Pursuant to section 109, EPA is currently reviewing the criteria document for the particulate matter NAAQS, and particle size is a factor being considered in this review. If the standard is revised, the rulemaking requirements of section 307(d) will apply.

EPA today is adopting its proposed deletion of the existing "fugitive dust exemption" and is deferring further action on any such "exemption" pending completion of the standard review process.

IX. Source

A. Proposed Definitions of "Source"

In the 1978 PSD regulations, EPA defined "source" as "any structure, building, facility, equipment, installation, or operation (or combination thereof) which is located on one or more contiguous or adjacent properties and which is owned or operated by the same person (or by persons under common control)." The Offset Ruling contained the same definition of "source."

In its June 1979 opinion in *Alabama Power*, the Court of Appeals rejected the definition of "source" in the PSD regulations. It concluded that Congress intended section 111(a)(3) of the Act to govern the definition of "source" for PSD purposes. That section defines "source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." In defining "source," EPA used the terms "building," "structure," "facility," and "installation," but then added "equipment," "operation," and "combination thereof." The court held that EPA, in adding those terms, exceeded its authority. It stated, however, that the Agency has substantial discretion to define one or more of the four terms in section 111(a)(3) to include a wide range of pollutant-emitting activities.

In its June opinion, the court also focused on the clause "which is located on one or more contiguous or adjacent properties and which is owned or operated by the same person (or persons under common control)." The court held that the approach, which that clause embodied, of grouping pollutant-emitting activities solely on the basis of proximity and control is generally acceptable, since the Agency had "evidenced an intention to refrain from unreasonable literal applications of the definition and instead to consider as a single source only common sense industrial groupings." 13 ERC at 1230.

In September 1979, EPA proposed to define "building, structure, facility and installation" for PSD purposes as "any grouping of pollutant-emitting activities which are located on one or more contiguous or adjacent properties and which are owned or operated by the same person (or by persons under common control)." As the preamble to the September proposal explains in detail, EPA concluded that the proposed definition would serve the purposes of PSD adquately by requiring review of those major projects that would cause air quality deterioration. At the same time, the definition would operate to avoid review of projects that would not increase deterioration significantly. In EPA's view, the dominant purpose of PSD review is to maintain air quality within the applicable increments.

In September, EPA proposed to define the four component terms differently for nonattainment purposes. Specifically, the Agency proposed to define "building, structure and facility" as it had proposed to define them for PSD purposes, and "installation" as "an identifiable piece of process equipment." One effect of that proposal would be the application of nonattainment requirements to a new piece of equipment that would emit significant amounts of a pollutant for which the area had been designated nonattainment, regardless of any accompanying emissions offsets at the plant. The preamble to the proposal explained: "Unlike the PSD provision, the nonattainment provisions are primarily intended not merely to prevent excessive increases in emissions, but to reduce emissions. This fundamental difference in purpose requires a different approach to defining the sources that will be subject to NSR." 44 FR 51932. EPA proposed to apply this definition to "incomplete" SIPs, i.e., those which did not demonstrate attainment based exclusively on currently approved requirements. Fully

"complete" SIPs could, under EPA's proposal, use the PSD definition.

In December 1979, the court issued its final opinion on the 1978 PSD regulations, which opinion superseded the June 1979 opinion. In the December opinion, the court reaffirmed its earlier conclusions that EPA must adhere to section 111(a)(3) in defining "source" for PSD purposes and that EPA has discretion to define the component terms "reasonably to carry out" the purposes of PSD. 13 ERC at 2039. The court added that "a plant is to be viewed as a source" and that the Agency "should" provide for the aggregation of polluting-emitting activities "according to considerations such as proximity and ownership." *Id.* at 2039 and 2040. But it warned that "EPA cannot treat contiguous and commonly owned units as a single source unless they fit within the four permissible statutory terms." Finally, the court said that any new definitions "should also provide explicit notice as to whether (and on what statutory authority) EPA construes the term source, as divided into its constituent units, to include the unloading of vessels at marine terminals and 'long-line' operations such as pipelines, railroads, and transmission lines. We agreed with Industry Groups that EPA has not yet given adequate notice as to whether it considers those industrial activities to be subject to PSD." *Id.* at 2040.

In January 1980, EPA solicited comment on the September proposals in light of the December opinion of the court. 45 FR 6803. EPA specifically asked for comment on whether factors other than proximity and control, such as the functional relationship of one activity to another, should be used. The Agency also asked for specific examples of cases where a literal application of the proposed definition would be unreasonable.

B. PSD: Comments on Proposal and Responses

Most commenters agreed that for PSD purposes EPA should adopt definitions of "building," "structure," "facility," and "installation" that would aggregate pollutant-emitting activities, instead of definitions that would restrict one or more of these terms to an individual activity. One commenter, however, argued that EPA should adopt for PSD purposes the same definitions of those terms that it had proposed to adopt for nonattainment purposes. The commenter asserted that the decision of the court in *ASARCO* v. *EPA*, 578 F.2d 319 (D.C. Cir. 1978), required the Agency to impose BACT on a new unit at a plant, even if the unit would result in no net increase in emissions. The commenter also asserted that the "all-encompassing definition * * * destroys the intent of the PSD program by letting opportunities for *reducing* increment consumption disappear before control technology standards (*i.e.*, NSPS) can be in place." (Emphasis added.)

EPA has decided to adopt for PSD purposes the sort of "all-encompassing" definitions that the commenter opposed. First, in its December 1979 opinion in *Alabama Power*, the court explicitly held that *ASARCO* "does not prevent aggregation of individual units of a plant into a single source." 13 ERC at 2040. Second, the dominant purpose of PSD review is not to reduce increment consumption, but rather to maintain air quality deterioration below an applicable increment. A definitional structure that aggregates pollutant-emitting activities into one "source" would serve that purpose, since it would allow only those changes at the "source" that would not significantly worsen air quality to escape review.

Some of the commenters who agreed that each of the component terms of "source" should aggregate pollutant-emitting activities also supported the use of proximity and control as the sole criteria for aggregating them. Most of those commenters, however, objected to the use of proximity and control as the sole criteria, some on the ground that the proposed definitions would be too inclusive and others on the ground that the definitions would not be inclusive enough.

The commenters who thought the definitions would be too inclusive asserted that they would group sets of activities at one site and under common control that are functionally or operationally distinct. Typical of the examples they gave are the following activities at one site and under common control: (1) a surface coal mine and coal-burning electrical generators that the mine supplies with coal; (2) a rock quarry and the portland cement plant that the quarry supplies with raw material; (3) a primary aluminum ore reduction plant, an aluminum fabrication plant and an aluminum reclamation plant; (4) a refinery, a service station, a research laboratory, a fertilizer factory, and a pesticide factory; and (5) a uranium mill and an oil field. With the language of the June 1979 opinion in mind, the commenters contended generally that to group the nominally different activities in each of those examples would violate any common sense notion of "plant."

The commenters who thought the proposed definitions would be too inclusive suggested a wide range of alternative definitions. For example, one group proposed that activities at one site and under common control should be combined only if: (1) they share the first three digits under the Standard Industrial Classification Code of the U.S. Department of Commerce, (2) they are dependent upon or affect the process of each other, (3) they use a common raw product or produce a common product, and (4) the proponent of the project in question does not show that the activities have entirely separate air quality impacts.

The commenters who thought the proposed definitions would not be inclusive enough urged the Agency to abandon control as a factor and adopt function in its place. Some of them described a plan by a group of independent companies to construct jointly a single coal-burning power plant to replace oil-burning power plants at various manufacturing sites belonging to those companies near to the site of the coal-burning plant. The commenters contended that EPA should treat the old plants and the new plant as being within one "source," so that the new plant might escape PSD review. They argued that the new plant would not deteriorate air quality, since presumably the decrease in emissions from the shutdown of the old plants would offset the increase from the new plant, and that to allow it to escape review would facilitate the national switch from oil to coal.

After considering the comments of those who objected to the use of proximity and control only, EPA has decided to adopt for PSD purposes a definition of "building, structure, facility, and installation" that is different from the one it proposed in September. The final definition provides that those component terms each denote "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same 'Major Group' (*i.e.*, which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively)."

In EPA's view, the December opinion of the court in *Alabama Power* sets the following boundaries on the definition for PSD purposes of the component terms of "source": (1) it must carry out

reasonably the purposes of PSD; (2) it must approximate a common sense notion of "plant"; and (3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation."

The comments on the proposed definition of "source" have persuaded EPA that the definition would fail to approximate a common sense notion of "plant," since in a significant number of cases it would group activities that ordinarily would be considered as separate. For instance, a uranium mill and an oil field would ordinarily be regarded as separate entities, yet the proposed definition would treat them as one.

In formulating a new definition of "source," EPA accepted the suggestion of one commenter that the Agency use a standard industrial classification code for distinguishing between sets of activities on the basis of their functional interrelationships. While EPA sought to distinguish between activities on that basis, it also sought to maximize the predictability of aggregating activities and to minimize the difficulty of administering the definition. To have merely added function to the proposed definition as another abstract factor would have reduced the predictability of aggregating activities under that definition dramatically, since any assessment of functional interrelationships would be highly subjective. To have merely added function would also have made administration of the definition substantially more difficult, since any attempt to assess those interrelationships would have embroiled the Agency in numerous, fine-grained analyses. A classification code, by contrast, offers objectivity and relative simplicity.

EPA has chosen the classification code in the *Standard Industrial Classification Manual, 1972,* as amended in 1977 ("*SIC*"), because it is both widely-known and widely-used. EPA has also chosen to use just one set of categories in the manual, those that describe each "Major Group" in the classification system and that bear a two-digit classification number, although the commenter who suggested that EPA use such a code also suggested that the Agency use the categories at the three-digit level. On the one hand, the two-digit categories are narrow enough to separate sets of activities into common sense groupings. In fact, most of the nominally different sets of activities in the examples given above would fall into a different two-digit category; only the fertilizer factory and the pesticides factory would fall into the same category. On the other hand, the categories are broad enough to minimize the likelihood of artificially dividing a set of activities that does constitute a "plant" into more than one group and the likelihood of disputes over whether a set of activities falls entirely into one category or another.

Each source is to be classified according to its primary activity, which is determined by its principal product or group of products produced or distributed, or services rendered. Thus, one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product. Where a single unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source which relies most heavily on its support. For example, a boiler might be used to generate process steam for both a commonly controlled and located kraft pulp mill and plywood manufacturing plant. If the yearly boiler output is used primarily by the pulp mill, then the total emissions of the boiler should be attributed to the mill.

In adopting the new definition of "source," EPA rejected the requests of those commenters who thought that the proposed definition would not be inclusive enough. As noted above, they urged that EPA formulate a definition that looked only to proximity and *function.* But such a definition by looking to function would unnecessarily increase uncertainty and drain the Agency's resources. In addition, such a definition would present groupings, such as the example the commenters gave, that would severely strain the boundaries of even the most elastic of the four terms, "building," "structure," "facility," and "installation."

Many commenters urged EPA to clarify the extent to which the final definition of those terms encompasses the activities along a "long-line" operation, such as a pipeline or electrical power line. For example, some urged EPA to add to the definition the provision that the properties for such operations are neither contiguous nor adjacent. To add such a provision is unnecessary. EPA has stated in the past and now confirms that it does not intend "source" to encompass activities that would be many miles apart along a long-line operation. For instance, EPA would not treat all of the pumping stations along a multistate pipeline as one "source."

EPA is unable to say precisely at this point how far apart activities must be in order to be treated separately. The Agency can answer that question only through case-by-case determinations. One commenter asked, however, whether EPA would treat a surface coal mine and an electrical generator separated by 20 miles and linked by a railroad as one "source," if the mine, the generator, and the railroad were all under common control. EPA confirms that it would not. First, the mine and the generator would be too far apart. Second, each would fall into a different two-digit *SIC* category.

Three commenters focused on whether and to what extent the emissions from each ship that would dock at a proposed marine terminal should be taken into account in determining whether the terminal would be "major" for PSD purposes. One commenter argued in effect that the emissions of each such ship that are quantifiable and occur while the ship is coming to, staying at or going from the terminal should be taken into account. In the view of that commenter, all of those activities would be "integral" to the operation of the terminal. Another commenter asserted that none of the emissions of any such ship should be taken into account, because ships are mobile sources. The remaining commenter contended that only the emissions that: (1) come from a ship which is under the proprietary control of the owner or operator of the terminal and (2) occur while the ship is at the dock should be included in an applicability determination. That commenter viewed the ability of the terminal owner or operator to regulate the behavior of a ship as the critical consideration.

The permit requirements of the final Part 52 PSD regulations apply to a collection of pollutant-emitting activities according to the "potential to emit" of just those activities in that collection which constitute a "stationary source." Whether and to what extent the emissions of ships that would dock at a terminal are to be taken into account in determining PSD applicability depends, therefore, on whether and to what extent the term "stationary source" in the final regulations encompasses not only the activities of the terminal itself, but also the activities of the ships while they are coming to, staying at, or going from the terminal.

The final definition of "building, structure, facility, and installation" resolves that question. EPA intends the term "stationary source" under that

definition to encompass the activities of a marine terminal and only those dockside activities that would serve the purposes of the terminal directly and would be under the control of its owner or operator. The term "dockside activities" means those activities in which the ships would engage while docked at the terminal. While "stationary source" encompasses combinations of activities, it is limited to combinations that would be "stationary," that is, fixed to the particular site. The activities of a terminal itself would be stationary, but all ship activities would not be. Only those that would directly serve the purposes of the terminal, such as loading and unloading, would be stationary since they alone would be in a sense fixed to the particular site. Hence, "stationary source" encompasses the activities of a marine terminal and only those dockside activities that would directly serve its purposes.

In addition, while "stationary source" encompasses combinations of stationary activities, it is further limited to those that would locate on "contiguous or adjacent properties." In EPA's view, only dockside activities would be located on "property" that is contiguous or adjacent to the terminal. Next, "stationary source" is also limited to those combinations of activities that would be "under the control" of one person or one group of persons who are themselves under common control. Hence, "stationary source" encompasses only the activities at a terminal and those dockside activities over which the owner or operator of the terminal would have control. Finally, the activities at a terminal and any such dockside activities fall under a single two-digit *SIC* category, namely "Water Transportation" (number 44).

Whether a particular dockside activitiy would directly serve the purposes of a terminal and would be under the control of its owner or operator depends upon the circumstances of a specific situation. Presumably, however, the activity of loading or unloading a ship would in every case directly serve the purposes of the terminal and would be under the control of its owner or operator to a substantial extent. In particular, the Agency would expect that no loading or unloading could occur without the consent of the owner or operator and consequently that the owner or operator would set, or at least have a significant say in the setting of, the schedule for loading or unloading.

In adopting this interpretation of "stationary source," EPA in large measure has rejected the arguments of the commenters on the ship emissions issue. First, to treat *all* of the activities of a ship while it is coming to, staying at, and going from a terminal would violate any common sense notion of "building," "structure," "facility," or "installation." To group just those activities occurring at the terminal that are essential to its functioning entirely comports with common sense. Second, an activity such as loading and unloading is certainly stationary, even if the ships that engage in it have mobility. Ships, moreover, are not "mobile sources" within the meaning of section 110(a)(5) of the Act, the provision restricting indirect source review. Finally, the fact that a terminal owner or operator does not own a particular ship does not mean that the owner or operator has no control over behavior of the ship at the terminal.

In deference to the position taken in *Alabama Power*, EPA has decided to treat the definition of "source" in the 1978 PSD regulations as *not* encompassing any ship or ship activity. As a result, ship emissions are not to be taken into account at all in determining whether a marine terminal is subject to review under the 1978 PSD regulations. A terminal which would not be subject to review under the 1978 regulations if ship emissions are not included in the determination of potential to emit can also be excluded from review under the new regulations provided certain conditions are met. These conditions are that the owner or operator of such a source has obtained each of the permits required under the SIP for the terminal before the date this notice appears in the Federal Register and commences construction on it within 18 months after that date.

The final definition of the component terms of "stationary source" differs from the proposed definition in one significant respect. The proposed definition used the phrase *"any grouping of* pollutant-emitting activities." The final definition uses the phrase *"all of the* pollutant-emitting activities." Taken literally, the proposed definition would have referred not only to all of the activities at a plant, but also to any subgroup of those activities. EPA, however, intended it to refer only to all of the activities. The final definition merely makes that explicit.

C. Nonattainment: Comments on Proposal and Response

Many commenters objected to EPA's proposed definition of "source" for nonattainment areas. Several commenters argued that there was no statutory basis for the distinction drawn in the proposal between "complete" and "incomplete" SIPs. Most of the commenters further claimed that the "dual definition" (*i.e.*, treating a source as both a plant and an individual piece of process equipment at the plant) both was illegal under the statute and *Alabama Power* and was wrong as a matter of policy.

The legal arguments presented by the commenters fell into two broad categories. First, they argued that the dual definition really defined "source" as a combination of surces, which had been forbidden by both *Alabama Power* and *ASARCO*. EPA therefore could, in these commenters' view, define "source" as either the entire plant or an individual piece of process equipment, but not both. These commenters opted for the former approach.

The second legal argument challenged EPA's contention that use of the plant-wide definition would be improper in nonattainment areas, because the purpose of the nonattainment new source review program is to reduce emissions, not to hold emissions constant. The commenters claimed that the Act gives primary responsibility for assuring reasonable further progress to the states, and the states therefore can choose whatever mix of strategies they want to achieve reasonable further progress. This suggested to the commenters that EPA had no authority to ban a plant-wide definition for new source review if the state could otherwise demonstrate reasonable further progress.

Several commenters also pointed to a variety of policy concerns which they felt militated against EPA's proposed dual definition. First, they argued that the definition would discourage technological innovation that could actually reduce emissions, because sources would be reluctant to modernize for fear that such requirements as LAER would be applied to them. In particular, they felt sources would be unwilling to retire old inefficient facilities and replace them with efficient cleaner ones. Second, some commenters claimed that there was no point to reviewing a facility where offsetting emissions could be obtained, since on the whole ambient air quality would not get any worse. Finally, many commenters complained that the definitional structure as a whole was far too complex, and they urged that EPA simplify the system both by eliminating the distinction between "complete" and "incomplete" SIPs and by adopting one definition for both PSD and nonattainment areas. Most commenters preferred the PSD

definition, although some urged that the dual definition be used.

In revising the Offset Ruling in January 1979, EPA adopted definitions of "source" and "modification" which had the effect of requiring any increase greater than 100 tons in the potential to emit of a plant to undergo nonattainment new source review, even if offsetting reductions at the plant were to accompany the change. The effect of the proposed definitions of "source" and "modification" which are being promulgated today would be basically the same as those in the Offset Ruling. Adoption of the proposed definitions would constitute, therefore, a continuation of an established approach to nonattainment new source review.

The comments on the dual definition have failed to persuade EPA that it should abandon the established approach at this time. As a result, the agency has decided to adopt the dual definition in each set of nonattainment regulations. For the reasons given below, EPA does not agree that the dual definition is either illegal or unsound from a policy standpoint. In addition, the agency has decided that the dual definition should be used regardless of whether the SIP is complete or incomplete. EPA agrees with the commenters that there is little support in the statute for defining "source" according to the complete or incomplete status of the SIP, and that the proposed definition was complicated.

The dual definition, by defining individual units as a "source," will bring more units in for review in areas with unhealthy air and thereby result in reducing emissions from the status quo. The legislative history of the Act indicates that new source review was intended to be an important tool in the drive towards attainment of ambient air quality standards. As the House Report stated:

> [M]aximum pollution control from new sources is necessary in order to permit room for maximum potential economic growth. This is particularly true in light of the requirement for reasonable further progress and the indications that emissions from many existing sources in nonattainment areas will be increasing (due to fuel switching, natural gas curtailments) or remaining static (due to delayed compliance orders, et cetera). Finally, the technology forcing purpose of the act is best served by requiring maximum feasible pollution control from these new sources in dirty air areas. For all these reasons, the committee adopted the requirement for proposed new or modified major stationary sources in nonattainment areas to meet the lowest achievable emission rate requirement.

H. Rep. No. 95–294, 95th Congress, 1st Sess. 215 (1977). In addition, after hearing testimony that no steel sources owned by five major steel companies were in compliance, the House inserted into section 173 a requirement that the owner of a proposed source or modification demonstrate that all other sources owned, operated, or controlled by him in the state are in compliance with the applicable SIP. *Id.* at 210–213. In this way, Congress meant to use new source review as a means of cleaning up *existing* sources as well.

To realize this goal fully, Congress intended that new source review be applied to the greatest extent possible. For example, Senator Muskie, in presenting the Clean Air Act Amendments of 1977 to the Senate, spoke of reviewing "any physical change which increases [emissions] * * *," and he went on to note:

> Thus, [under the offset ruling and Part D NSR requirements] a new source is still subject to such requirements as "lowest achievable emission rate" even if it is constructed as a replacement for an older facility resulting in a new reduction from previous emission levels. 123 Cong. Rec. at S 13702 (daily edition, August 4, 1977).

Since the dual definition would bring in more sources or modifications for review than would the plant-wide definition used for PSD purposes (including many replacement facilities which would not be reviewed under a plant-wide definition), use of the dual definition clearly is more consistent with Congressional intent.

The dual definition also is consistent with *Alabama Power* and *ASARCO*. *Alabama Power* held that EPA had broad discretion to define the constituent terms of "source" so as best to effectuate the purposes of the statute. Different definitions of "source" can therefore be used for different sections of the statute. *See* 13 ERC at 2039. As EPA discussed in detail in its proposal, the purpose of the nonattainment provisions is to "positively reduce emissions," not merely to hold emissions constant. In addition, unrestricted use of meeting emissions at an entire plant in nonattainment areas would make attainment more difficult, since many of the limited number of cost-effective opportunities to reduce emissions will in fact be used to avoid review. *See* 44 FR 51932. The dual definition therefore comports with the purposes of Part D of the Act.

Moreover, *Alabama Power* and *ASARCO* taken together suggest that there is a distinction between Clean Air Act programs designed to *enhance* air quality and those designed only to *maintain* air quality. In *ASARCO*, the Court of Appeals for the District of Columbia Circuit struck down the definition of "source" for new source performance standards (NSPS), which had employed a "bubble" concept. An important element in the court's decision was its belief that the "bubble," by allowing sources to escape NSPS, was inconsistent with the purpose of NSPS, which was to improve air quality. *See* 578 F.2d at 327–28. But in *Alabama Power*, the same court held that for PSD purposes, EPA must use a "bubble" approach, precisely because PSD is designed to maintain air quality and therefore deals with "a significantly different regulation and statutory purpose." 13 ERC at 2044.

Under this analysis, use of a plant-wide definition to avoid new source review would appear to be inappropriate in nonattainment areas, since the purpose of nonattainment SIPs is to improve existing air quality so as to attain the ambient air quality standards. EPA therefore believes that it would be more consistent with the purposes of the Act not to permit states to choose a plant-wide definition of source.

Promulgation of the dual definition follows the mandate of *Alabama Power*, which held that, while EPA could not define "source" as a combination of sources, EPA had broad discretion to define "building," "structure," "facility," and "installation" so as to best accomplish the purposes of the Act. 13 ERC at 2039. This holding contemplates that one term (such as "building") may be more inclusive than another term (such as "installation"), and so a "building" may include many "installations." In this way, a "source" can, under *Alabama Power*, be composed of smaller "sources," yet not be a combination of sources. The dual definition fits into *Alabama Power*, since under EPA's definitional scheme, a "source" is either an individual piece of process equipment or the entire plant; it is not a combination of sources. That is, when deciding whether a source must undergo new source review, the reviewing authority must determinine whether there was a significant increase in emissions at either a "major" individual piece of equipment or at the plant as a whole. Wherever such an increase occurs is a "source." Thus the plant itself is a source, not a combination of sources, although it may contain smaller sources.

EPA recognizes that use of different definitions for PSD and nonattainment areas adds to the complexity of the permitting process. But this additional complexity is outweighed by the need for a more inclusive definition of source in nonattainment areas in order to assure attainment of standards.

Although it is claimed that some sources may not be willing to modernize their facilities due to the perceived added expense of LAER and the need to demonstrate statewide compliance, EPA believes that its approach is justified by the fact that the dual definition will bring in more sources and modifications for review and will require better pollution control technology in nonattainment areas.[10]

EPA disagrees that use of a plant-wide definition would allow a plant with a new installation to achieve the same emissions reductions as LAER, but in a less expensive manner by finding offsets elsewhere in the plant. This argument assumes that LAER is markedly more costly than the requirements that would otherwise apply. EPA believes that its own past actions, and those of the states, indicate that LAER need not and is not generally being interpreted in this manner.

EPA believes, and most commenters agreed, that new facilities should install state-of-the-art control technology. Such a requirement is imposed by the Clean Air Act for major new sources in PSD areas (BACT), for major new sources in nonattainment areas (LAER), and whenever EPA has set new source performance standards (NSPS). EPA therefore intends to interpret the LAER requirement in a reasonable manner, as it believes it has in the past, and to take a close look whenever LAER would be substantially stricter than these other requirements.

EPA intends that its interpretation of "building, structure, and facility" be identical to that for "building, structure, facility, or installation" used for PSD purposes.[11]

X. Modification

This section discusses the final PSD and nonattainment definitions of "major modifications" and "net emissions increase" which EPA is promulgating in this notice. The section first describes those final provisions. It then focuses on each of their major aspects, giving in particular the relevant proposal, the comments on it and EPA's responses. An example of how the definitions work appears at the end of the section. The section also discusses a provision which appears in the PSD and nonattainment definitions of "major stationary source," but which stems from the final formulation of "major modification." That provision establishes that a physical change at a "minor" stationary source which change by itself would constitute a "major stationary source" shall be treated as a "major stationary source."

A. Final Definitions of "Major Modification" and "Net Emissions Increase"

With the final amendments announced here, the Part 51 and Part 52 PSD regulations now define "major modification" as any *"physical change"* or *"change in method of operation"* at a major stationary source which would result in a *"significant net emissions increase"* in any pollutant subject to regulation under the Act. *See* §§ 51.24(b)(2) and 52.21(b)(2).

While the new PSD regulations do not define "physical change" or "change in method of operation," they provide that those phrases do not encompass certain specific types of events. Those types are: (1) routine maintenance, repair and replacement; (2) a fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or due to a natural gas curtailment plan under the Federal Power Act; (3) a fuel switch due to an order or rule under section 125 of the Clean Air Act; (4) a switch at a steam generating unit to a fuel derived in whole or in part from municipal solid waste; (5) a switch to a fuel or raw material which (a) the source was capable of accommodating before January 6, 1975, so long as the switch would require no change in any preconstruction permit condition established after that date under the SIP (including any PSD permit condition) or (b) the source is approved to make under a PSD permit; (6) any increase in the hours or rate of operation of a source, so long as the increase would require no change in any preconstruction permit condition established after January 6, 1975 under the SIP; and (7) a change in the ownership of a stationary source.

The new PSD regulations define "significant" in terms of *de minimis* thresholds for each pollutant subject to regulation under the Act. Those thresholds appear in §§ 51.24(b)(21) and 52.21(b)(21). For example, the threshold for sulfur dioxide is 40 tons per year. A "net emissions increase" in sulfur dioxide below that level is not "significant." For a fuller discussion of the thresholds, see the section entitled *De Minimis* Exemptions.

Finally, the new PSD regulations contain definitions of "net emissions increase," which appear as §§ 51.24(b)(3) and 52.21(b)(3). Under those definitions, "net emissions increase" denotes the positive sum of any increase in "actual emissions" from a particular physical or operational change at a source and any other increases and decreases in "actual emissions" that are contemporaneous with the particular change and otherwise creditable.

The first step in determining whether a "net emissions increase" would occur is to determine whether the physical or operational change in question would itself result in an increase in "actual emissions." If it would not, then it could not result in a "net emissions increase." If it would, the second step is to identify and quantify any other prior increases and decreases in "actual emissions" that would be contemporaneous with the particular change and otherwise creditable. The third step, finally, is to total the increase from the particular change with the other contemporaneous increases and decreases. If the total would exceed zero, then a "net emissions increase" would result from the change.

The definitions of "net emissions increase" specify which increases and decreases in "actual emissions" are contemporaneous. Under the definition in the Part 52 PSD regulations, increases or decreases are contemporaneous with a proposed change only if they occur between two dates: first, the date five years before construction "commences" on the proposed physical or operational change in question and, second, the date the increase from that change "occurs." An increase from a physical change "occurs" when the affected emissions unit becomes operational and begins to emit a particular pollutant. Any unit that requires shakedown becomes operational only after a reasonable shakedown period (not to exceed 180 days). Under the definition in the Part 51 regulations, a state in revising its SIP may set a period other than the five-year period of the Part 52 regulations to define what is contemporaneous and what is not, so long as the period is not unreasonably long.

The definitions of "net emissions increase" in the PSD regulations also specify which contemporaneous increases and decreases in "actual emissions" are creditable. A contemporaneous increase or decrease is creditable only if the relevant reviewing authority has not relied on it in issuing a PSD permit for the source,

[10] Contrary to one commenter's argument, EPA believes that the dual definition will not cause sources to locate in clean areas. Any such source would be subject to PSD review in any event.

[11] One commenter requested EPA define "source as one emitting the criteria pollutants, and not "any pollutant regulated under the Act." EPA has decided to retain its definition, since it comports with section 302(j) of the Act. However, pursuant to section 172(b)(6), EPA will require new source review permits only for those pollutants for which an area has been designated nonattainment and for which the source is major.

and that permit is still in effect when the increase in "actual emissions" from the particular change occurs. A reviewing authority "relies" on an increase or decrease when, after taking the increase or decrease into account, it concludes that the proposed project would not cause or contribute to a violation of an increment or ambient standard. A contemporaneous increase or decrease in "actual emissions" of sulfur dioxide or particulate matter that occurs before the applicable baseline date is creditable only if, in addition, it is required to be considered in calculating how much of a particular increment remains available.

Finally, the definitions of "net emissions increase" in the new PSD regulations specify the extent to which any contemporaneous and otherwise creditable increase or decrease is creditable. Any such increase is creditable to the extent that the new level of "actual emissions" exceeds the old level of "actual emissions." Any such decrease is creditable only to the extent that (1) the old level of "actual emissions" (or the old level of "allowable emissions," if it is lower) exceeds the new level of "actual emissions," (2) the decrease is federally enforceable at the time construction begins on the proposed physical or operational change which it is intended to offset, and (3) the decrease has roughly the same health and welfare significance as the increase from the proposed change.

Under the final PSD regulations, the phrase "actual emissions" means the rate at which an emissions unit actually emits a particular pollutant. *See* §§ 51.24(b)(21) and 52.21(b)(21). In general, that rate as of a particular date equals the average rate in tons per year at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and is representative of normal source operation. The reviewing authority may presume that any "source-specific allowable emissions" for the unit is equivalent to the actual emissions of the unit. For any unit which has yet to begin normal operations on the date in question, its actual emissions equal its "potential to emit" on that date. For a fuller discussion of the concept of "actual emissions" and in particular of what constitutes "source-specific allowable emissions," see the section on Increment Consumption.

The final PSD regulations also describe in detail the concept of "allowable emissions." *See* §§ 51.24(b)(16) and 52.21(b)(16). That phrase means in essence the maximum rate at which an emissions unit under the most stringent of certain legal constraints may emit a particular pollutant. The legal constraints are (1) any applicable standards in 40 CFR Parts 60 and 61, (2) any applicable SIP limitations, including any with a future compliance date, and (3) any applicable condition in a permit issued under the SIP that is federally enforceable, also including any condition with a future compliance date.

The final amendments to the Offset Ruling, 40 CFR 51.18 and 40 CFR 52.24 which are announced here also include new definitions of "major modification," "significant," "net emissions increase," "actual emissions," and "allowable emissions." In general those definitions follow the pattern of the PSD definitions. Only the definitions of "net emissions increase" in those nonattainment provisions vary significantly. They add that a decrease in "actual emissions" which is contemporaneous with the increase in question may be credited only if and only to the extent that the relevant permitting authority has not already accepted it as a satisfactory "offset" in issuing a preconstruction permit under the SIP.

B. No Net Increase

The *Alabama Power* decision rejected EPA's regulatory approach of requiring PSD review of potential emissions increases at existing stationary sources only when such increases would equal or exceed the 100/250 ton threshold used in the review of new sources. It held instead that a change in a major stationary source is subject to review only if it would result in any significant net increase. In response, EPA proposed on September 5, 1979, an approach that would subject to new source review (NSR) under the relevant PSD or nonattainment provisions only each significant net increase that would occur in the potential to emit of a major stationary source. Under the proposal, a significant net increase was to be an overall increase in the potential to emit of the source equal to or greater than a pollutant-specific emissions cutoff (*see De Minimis* Exemptions), taking into account contemporaneous emissions increases and decreases at the same source. An exception to this general rule of netting contemporaneous increases and decreases was to be the case of construction restrictions under sections 110(a)(2)(I) and 173(4). There, accumulated increases would count toward triggering the growth prohibitions, without regard to any contemporaneous reductions occurring at the same source.

Public comment supported this proposal (except with respect to the construction restrictions) as the clear and proper interpretation of the *Alabama Power* decision. Sixty-two of sixty-three commenters endorsed the general netting approach to modification taken in the proposal, although several took issue with certain of the specific rules relating to the concept (see discussion below). Several commenters felt that requiring any significant net increase to undergo review was too strict on existing sources as compared with new sources, since new sources can emit up to 100/250 tons per year and still not be subject to review. The terms of the Act and the court decision preclude allowing such a general exemption for existing sources. Pursuant to *Alabama Power*, the Administrator is today promulgating the netting concept for determining the review applicability of changes at existing major stationary sources (consistent with each program's definition of source). This promulgation affects regulations for PSD (40 CFR 52.21 and 40 CFR 51.24), nonattainment NSR (Emissions Offset Interpretative Ruling and 40 CFR 51.18(j), Review of New Stationary Sources and Modifications), and the construction restrictions under sections 110(a)(2)(I) and 173(4), (40 CFR 52.24, Statutory Restriction on new Stationary Sources). Allowance of netting for determining the applicability of 40 CFR 52.24 is a change from the proposal and is discussed below.

C. Pollutant Applicability

EPA proposed to require preconstruction review only if the increase in potential to emit would be for a pollutant which the source emits in major amounts. Once an increase in the major pollutant triggered PSD review then review would be required for all regulated pullutants emitted in greater than *de minimis* amounts as a result of the modification. Review would also be required if the emissions change itself were equivalent to a major stationary source.

Only limited comment was received on EPA's proposal to require review where major changes in emissions of minor pollutants or greater than *de minimis* changes in emissions of a major pollutant would occur. While a few groups endorsed the September 5 proposal, one group argued that *Alabama Power* did not restrict PSD applicability to just modifications involving the pollutant(s) which the source emits in major amounts. That group pointed out that section 111(a)(4) of the Act defines "modification" as "any physical change in, or change in the method of operation of, a stationary

source which increases the amount of *any* air pollutant emitted by such source or which results in the emissions of *any air pollutant not previously emitted.*" (Emphasis added.)

The Administrator agrees that requiring review for a net emissions increase in any pollutant subject to regulation under the Act is consistent with the *Alabama Power* decision. Consequently, EPA is promulgating a final rule that requires PSD preconstruction review for net emissions increases in greater than *de minimis* amounts at a major stationary source for any pollutant subject to regulation under the Act emitted by the source, regardless of whether the source is major for that pollutant.

The Administrator is not changing the September 5 proposal with respect to pollutant applicability in nonattainment areas. *See* Geographic and Pollutant Applicability. The source must be major for the nonattainment pollutant(s) and must make a greater than *de minimis* emissions change in such a pollutant in order to trigger nonattainment review for that pollutant(s). A PSD review, however, would be triggered if a greater than *de minimis* change occurs at that major source for any regulated pollutant emitted by the source other than the nonattainment pollutant(s).

D. Netting of Actual Emissions

EPA proposed on September 5 that an activity be deemed a major modification when the "potential to emit" of the major stationary source experiences a net increase greater than a *de minimis* amount, taking into account all contemporaneous changes. EPA also proposed that a reduction would be creditable only if the physical capability of the source to emit a pollutant were actually reduced. In addition, where "allowable emissions" for a source, as defined in the 1978 PSD regulations and the Offset Ruling would be less than its "potential to emit," no credit would be given for reducing potential emissions to "allowable emissions." "Allowable emissions," as defined in those regulations, meant the emissions rate calculated using the maximum rated capacity of the source and is represented by the most stringent than any of the following: (1) any applicable standards in 40 CFR Parts 60 and 61; (2) any applicable SIP emissions limitations; and (3) any emissions rate specified as a permit condition under the SIP. The applicable SIP limitation in the case of designated nonattainment areas included the emissions rate that was assumed for the source in the attainment demonstration and in the schedule for making reasonable further progress.

Forty of forty-two commenters favored an allowable emissions baseline, for determining whether a net emissions increase would occur, instead of one using "potential to emit." The other two commenters endorsed EPA's proposal. Many also complained of the different criteria for determining "potential to emit" from new and existing sources. (Under the proposal, "allowable emissions" and physical incapability could have constrained the "potential to emit" of existing but not new stationary sources.)

There are problems with using a baseline for netting that is based on the existing source's "potential to emit." A computation of an existing source's potential emissions could give a figure considerably higher than what it is actually emitting. This would be especially true if the source operated only a small part of the time or used considerably cleaner fuels than it is allowed to burn. Such an approach would therefore create a "paper offset" that could permit actual air quality to deteriorate seriously, while the change which increased actual emissions avoided NSR. Similar problems would arise if offsets were based on allowable emissions, as recommended by most commenters.

In the June 1979 opinion in *Alabama Power*, the court held that the definition of "modification" in section 111(a)(4) governs the definition of that term for PSD purposes. Section 111(a) provides that a "modification" is "any physical change in, or change in the method of operation of, a stationary source which increases *the amount* of any air pollutant *emitted* by such source or which results in *the emissions* of any air pollutant not previously *emitted.*" (Emphasis added.) Although the *underlined* words in the definition appear to refer to what the source is actually emitting at a particular time, the court in the June opinion described the concept of "modification" in terms of changes in the "potential to emit" of a source. As a result, EPA proposed definitions which also referred to changes in "potential to emit."

In its December 1979 opinion, however, the court used an entirely different set of terms to describe "modification." Instead of using "potential to emit," it used language which, like the section 111(a)(4) definition, suggest changes in actual emissions. For example, at one point the court states: "If these plants *increase* pollution, they will generally need a permit. Exceptions to this rule will occur when the *increases* are *de minimis*, and when the *increases* are offset by contemporaneous decreases of * * *" pollutants, as we discuss below (Emphasis added.)

Following the lead of the court, EPA has also shifted the focus of its regulatory definitions from "potential to emit" to "actual emissions." For both PSD and nonattainment purposes, a "major modification" is now any significant "net emissions increase" at a major stationary source that results from certain changes. "Net emissions increase" is, in turn, roughly any net increase in "actual emissions." Not only are those definitions consistent with the court's view of section 111(a)(4), but they also avoid the "paper offset" problem described above, thereby better serving PSD and nonattainment purposes.

E. Contemporaneous Increases and Decreases

Under *Alabama Power*, a modification is any net increase in emissions that would result form "contemporaneous" changes at a major stationary source. The court decision left to EPA the task of defining what changes should be considered "contemporaneous."

A narrow interpretation of the term "contemporaneous" would restrict creditable decreases in emissions to those occurring at the same time as the emissions increases to be offset. The administrator decided against proposing such an interpretation, since it might promote the continued operation of old or obsolete equipment in order to preserve offset credit. Instead, EPA proposed a system that would grant credit for *any* post-promulgation emissions reduction and for certain pre-promulgation emissions reductions involving recent shutdowns or production curtailments. In order to be creditable, the reductions were to be enforceable before operation of the emissions unit(s) that would result in the emissions increases (except that a 180-day shakedown period could be granted for replacements). A preconstruction notice was also proposed as a mandatory means to record any reduction credit. (For a discussion of that proposed notice requirement, see the section entitled Notification.)

On January 30, 1980 (45 FR 6802), EPA solicited additional comment on its proposal for "contemporaneous." In particular, the Administrator asked whether a three-year time limit should be imposed for qualifying reductions as "contemporaneous." The proposed three-year time cap would have run from the time of the emissions reduction to the time that the source would have filed any necessary permit application

for the prospective emissions increase(s). Where a permit would have not been required, the reference time would instead be the date on which construction commenced on the change resulting in the emissions increase.

Several comments were received on the September 5 proposal. Many confused the dates for accumulation at minor stationary sources (see discussion below) with the time limits for "contemporaneous" changes at major stationary sources. The majority of commenters on the January 30 Federal Register notice were from the industrial sector and they urged EPA to treat *any* emissions decrease which occurs before a proposed increase as being "Contemporaneous" with that increase. EPA however, has rejected those urgings. To credit any decrease that occurs before a proposed increase would violate any common sense notion of what is "contemporaneous," since a period of contemporaneity must have some definite boundaries.

EPA agrees with those industry commenters, however, to the extent that they contended that the period of contemporaneity should be fairly large. In particular, EPA believes that the period should be wide enough so as to minimize any incentive for keeping old or obsolete equipment in operation beyond its usefulness. As a result, EPA has set five years, plus time for construction, as the period of contemporaneity for the purposes of the Part 52 PSD regulations, the Offset Ruling and the construction moratorium. Specifically, the definition of "net emissions increase" in each of those regulations provides that a decrease in "actual emissions" may be credited only if it occurs between the date five years before construction "commences" on a proposed physical or operational change and the date the increase in "actual emissions" from that change occurs. A five-year limit was selected for those regulations rather than a three-year value, since five years is frequently used as the time duration over which corporate expansion planning is conducted.

For the purposes of the Part 51 PSD and nonattainment regulations, EPA has established that each state may set the period of contemporaneity for its own NSR regulations. The state may not, however, set a period of unreasonable or undefined length.

F. Otherwise Creditable Increases and Decreases

Whether an increase or decrease in "actual emissions" is creditable for PSD or nonattainment purposes depends, not only on whether it is contemporaneous with the increase in question, but also on certain other factors. First, under each of the PSD and nonattainment definitions, a prior increase or decrease is creditable only if the relevant reviewing authority has not relied upon it in issuing a permit under the relevant NSR program. As stated earlier, a reviewing authority "relies" on an increase or decrease when, after taking the increase or decrease into account, it concludes that the proposed project would not cause or contribute to a violation of an increment or ambient standard. The purpose of that rule is to "wipe the slate clean." Once the reviewing authority has evaluated a significant net increase in issuing an NSR permit the net increase should not be a factor in deciding whether subsequent events should undergo scrutiny, too.

Second, under the PSD definition of "net emissions increase," an increase or decrease in actual emissions of sulfur dioxide or particulate matter which occurs before the baseline date is creditable only if it would be considered in calculating how much of an increment remains available. In formulating that definition, EPA sought to establish as close a correspondence as possible between what consumed increment and what must undergo NSR for PSD. Without that rule, some changes that *would* consume increment could escape review because of a prior decrease that was subsumed in the baseline concentration. In addition, without that rule, some changes that *would not* consume increment could have to undergo review because of a prior increase that was also subsumed in the baseline concentration.

G. The Extent to Which Increases and Decreases are Creditable

Each of the definitions of "net emissions increase" in the PSD and nonattainment regulations contains provisions which govern the extent to which a creditable increase or decrease in "actual emissions" may be credited.

The rules in each of those definitions relating to increases are simple. An increase is creditable to the extent that the new level of "actual emissions" at the emissions unit in question exceeds the old level. The old level of "actual emissions" is that which prevailed just prior to the physical or operational change which caused the increase. The new level is that which prevails just after the change.

The rules relating to decreases that are common to each of the definitions are more complex. First, a decrease is creditable only to the extent that "the old level of actual emissions or *the old level of allowable emissions, whichever is lower*, exceeds the new level of actual emissions." (Emphasis added.) Since "allowable emissions" encompasses any federally enforceable requirement, including any with a future compliance date, the underlined language prevents a company from taking credit for decreases that it has had to make or will have to make in the future. EPA concluded that to give credit for a decrease a company has had to make in order to bring an emissions unit into compliance was unwise, since together with the five-year "contemporaneous" period it would create an incentive to stay out of compliance. Furthermore, it would be contrary to the purposes of the Act and good sense to provide what is in essence a benefit for recalcitrance. Similarly, EPA concluded that to give credit for a decrease a company will ultimately have to make anyway in order to meet a requirement by a certain date would also be unwise, since it would encourage procrastination. Further, allowing decreases which fulfill preexisting requirements to be used to avoid review would undermine the purposes of the PSD and nonattainment programs by interfering with efforts to preserve or achieve attainment.

Second, a decrease is creditable only to the extent that it is "federally enforceable" from the moment that actual construction begins on the physical or operational change which causes the "actual emissions" increase in question. The purpose of that rule is to ensure that the decrease is real and that it remains in effect. The term "federally enforceable" is defined in the regulations as any limitation or conditions which EPA can enforce, such as any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved under 40 CFR 51.1 and 40 CFR 51.24.

Finally, a decrease is creditable only to the extent that it has the same health and welfare significance as the increases in question. By this provision, EPA seeks mainly to prevent an increase in emissions with considerable health and welfare significance from escaping review merely because of a contemporaneous decrease in less harmful emissions. The basic health and welfare protection purposes of the Act mandate this provision.

The definitions of "net emissions increase" in the nonattainment regulations contain a restriction on crediting decreases that the PSD regulations do not contain. Specifically, they provide that a permitting authority may not credit a decrease to the extent that any permitting authority has

already accepted the decrease in satisfaction of the offset requirements of the applicable nonattainment regulations and consequently has issued a preconstruction permit to any source or modification, including the source at which the decrease occurred. The purpose of that rule is to prevent any "double crediting" of decreases in "actual emissions." Double crediting would allow air quality to deteriorate without prior review.

EPA is considering whether to introduce a provision to prevent double crediting in the PSD context. A discussion of the problem appears in the section on Increment Consumption.

H. Accumulation

On September 5, 1979, EPA proposed to continue the current policy of requiring PSD and nonattainment NSR when aggregate new emissions from individually minor units at the same stationary source, which itself was minor as of a certain date, are sufficient to require the series of changes to be treated as a major stationary source. In addition, the Administrator proposed to make the current policy consistent with the *Alabama Power* decision by applying NSR when the aggregate *net* increase in potential to emit after the applicable date qualifies it as a major stationary source (the existing rules accumulate only emissions increases and do not take decreases in account). For PSD review, the date from which emissions increases were to be aggregated was August 7, 1977, the date found in the 1978 PSD regulations. The proposed December 21, 1976 date for each of the nonattainment regulations, including the construction moratorium, marks the time when sources constructing in nonattainment areas were placed on notice that accumulation could later subject them to review.

EPA also proposed that, once a series of individually minor changes or one major change at a minor stationary source had qualified for review, the control technology assessment would focus on the last changed unit triggering review while the air quality assessment would consider all aggregated emissions.

Finally, the Administrator proposed on September 5 that accumulation would also govern the review of individual *de minimis* changes at major stationary sources. Once a source had aggregated enough emissions to make it major, a subsequent emissions increase of any size at the source would have to undergo review, unless the increase together with any contemporaneous increases or decreases of any size would qualify as a *de minimis* increase.

Twenty of the twenty-three comments received did not favor retaining the accumulation concept, even with the addition of netting. Two other commenters endorsed accumulation, but with different starting dates. Two industrial commenters claimed that accumulation cannot be legally required, since section 111(a)(4) defines modification in terms of *any change* and not a *series of changes* at a stationary source. Most other commenters agreed that neither the court nor the Act takes a position on accumulation, but they requested that the Agency not adopt or maintain such a concept. These commenters claimed that both major and minor source accumulation complicates the regulations and could eventually subject the most minor of emissions changes to review. The increase in paperwork, and the administrative strain of trying to document and report *de minimis* emissions changes, were claimed to be overwhelming, costly, and counterproductive.

These concerns might have had merit if the proposed *de minimis* emission levels had not been raised in the final regulations and the accumulation of *de minimis* changes was to continue even after a preconstruction permit had been issued. It was suggested that the general NSR procedures found in all SIPs be relied upon to effect good control for the *de minimis* or minor emissions changes, instead of accumulation. Commenters stressed that, in any event, accumulation of *de minimis* increases should run over the same time period for crediting contemporaneous reductions.

The Administrator has reconsidered the need for an accumulation rule and has decided to retain accumulation to determine if a greater than *de minimis* increase would occur at a major stationary source and to delete accumulation for aggregating changes at minor stationary sources. The primary reason for proposing accumulation at minor sources was to prevent circumvention of the regulations by the systematic construction of carefully sized emissions units which only in the aggregate would trigger review. Even though all signficant changes at a source would face reveiw once the source became major, a significant loophole was thought to exist. For example, absent an accumulation rule, a company could construct a 498-ton source without having to get a PSD permit by constructing first one-half of it and then subsequently the other half. The Administrator, however, does not find adequate support in the Act for applying PSD review to the change at a minor source which would make the source major. Section 165 applies only to major emitting facilities on which "construction" commences after a specified date, where the term "construction" includes "modification." Similarly, section 172(b)(6) requires permits for the construction of new or modified major stationary sources. EPA believes that, in general, PSD and nonattainment review cannot be applied to a modification unless it would occur at a source that is already major. The one exception to this rule is where a proposed addition to an existing minor stationary source would be major in its own right. Such construction is equivalent to a new major stationary source and should therefore be subject to PSD and nonattainment review. A new subsection in each of the PSD and nonattainment regulations embodies that view.

In general, under the promulgation announced here a series of minor changes at the same minor stationary source will not be accumulated. On the other hand, a series of individually *de minimis* changes at a major stationary source would be accumulated within a contemporaneous time frame to see if a review would be required. This is reflected in the definitions of "net emissions increase" in the PSD and nonattainment regulations. Plainly, a series of individually *de minimis* increases in emissions in the aggregate deteriorate air quality significantly.

I. Restrictions on Construction

EPA proposed that the netting of emissions changes would not be permitted in areas subject to construction restrictions under section 110(a)(2)(I) or 173(4). EPA based this proposal on an interpretation that Congress intended all forms of offsets to cease after June 30, 1979, in the absence of an approved Part D plan. This policy would also have promoted the timely submittal of attainment plans and prevented the nonattainment problem from growing worse while the plan was being developed. The Administrator believed that sources might convert reductions later needed for attainment into offsets before the plan requiring those reductions could be adopted and approved.

Thirty-two of thirty-five commenters said that the proposed "increase only" approach was unacceptable. No substantial support was given by the three that favored it. Several questioned the legality of the proposed interpretation and claimed that *Alabama Power* authorized only a netting approach, despite any programmatic sense that another

approach might have. Several asserted that EPA's proposal would discourage early cleanup and actually perpetuate the existing air quality problem.

The Administrator has reconsidered the interpretation that led to the proposal of the "increase only" approach for carrying out the growth restrictions and concluded that the *Alabama Power* decision does not support it. Thus, in the final rules promulgated today, a major stationary source can construct in a growth restricted area, if sufficient contemporaneous, creditable net reductions are found (subject to the limitations on reconstruction described below).

J. Reconstruction

In the September 5, 1979 proposal, a reconstruction (roughly, improvements at an existing source which equal 50% or more of the capital cost for replacing the source) was to be treated as if it were a new source for purposes of NSR under both PSD and nonattainment rules. Under the proposal, a reconstructed major stationary source would be subject to review regardless of any contemporaneous emissions reductions that would occur at the same source. The Administrator proposed this approach in accordance with Congressional intent to subject new construction in nonattainment areas to requirements such as meeting the lowest achievable emission rate (LAER), even though a replacement of an older unit would result in a net reduction from previous emission levels (*see* 123 CONG. REC. 13702, col. 2 (daily ed. August 4, 1977) (statement of Senator Muskie)). In the agency's view nonattainment areas require very stringent NSR Procedures to overcome the inertia of the nonattainment problem. Having a reconstruction provision would promote maximum air quality improvements from an area's limited reduction capability by requiring more construction projects to meet LAER and bring other sources in the State under common control into compliance with the SIP.

The reconstruction rule was also proposed for PSD in an effort to be consistent with nonattainment NSR. Although the Administrator recognized that the air quality rationale for having reconstruction in nonattainment areas was considerably stronger than that for PSD inclusion, it was believed that less confusion would result with a parallel application of the reconstruction rule.

All ten commenters on the reconstruction topic voiced general disapproval for the proposal. Eight of the ten favored dropping the concept entirely from both sets of regulations, with the remaining two requesting that its applicability be restricted. They advised that EPA should rely instead on the reconstruction provisions of NSPS and NESHAP to ensure such construction would apply adequate control technology. Commenters complained that review criteria based solely on the replacement cost of equipment regardless of air quality improvements make little sense for NSR rules charged with safeguarding air quality. They further argued that the added regulatory complexity inherent to the inclusion of a reconstruction provision was not warranted and its addition to NSR would not be consistent with the "no net increase" exemption under *Alabama Power*.

The Administrator agrees that the reconstruction requirement makes only limited air quality sense for PSD and has reconsidered the need to retain this concept for the program. It is true that a reconstructed source not otherwise subjected to PSD review as a major modification (i.e., such source would not cause a significant net emissions increase) would not interfere with the PSD air quality objective of allowing only limited deterioration of existing air quality. On the other hand, the PSD objective of maximizing future use of the allowable increments through application of best available control technology (BACT) would not be strictly met. Nevertheless, the Administrator believes that the general PSD objective of safeguarding existing air quality from significant degradation will not be undermined by deleting the requirement for review of reconstructions.

The proposal would have implemented reconstruction for PSD only on a plant wide basis. Thus, an entire plant would have to be reconstructed in order for it to be subjected to PSD review as a reconstruction. Few instances of plantwide reconstruction are expected. The limited applicability under PSD brings further doubt as to the real need for the added complexity that a reconstruction provision would bring to determining the permit applicability of construction projects. Furthermore, the deletion of reconstruction from PSD would avoid some increment tracking problems; treating reconstruction as new PSD sources could lead to increment consumption unrelated to actual air quality changes.

The Administrator does not agree with the commenters who argued that applying "reconstruction" in nonattainment areas would bring unwarranted complexity and no air quality benefits. As explained in the proposal, EPA believes that the reconstruction provision within nonattainment NSR rules is consistent with stated Congressional intent and programmatic goals to get reasonable e quality improvements from each major construction activity. Since *Alabama Power* did not strictly bind EPA in nonattainment concerns and since the reconstruction concept was not expressly precluded, the Administrator has determined that reconstruction is warranted in nonattainment areas and is today promulgating this concept as proposed for nonattainment NSR rules.

Commenters also asked that several exemptions be considered if a reconstruction rule were promulgated. Among the exemptions suggested were (1) current NSPS exemptions for modifications, (2) Fuel-Use Act exemptions, (3) involuntary replacemer of damaged equipment, and (4) voluntary fuel switches. The Administrator is not promulgating any of these exemptions into the reconstruction provision. First, the current NSPS exemptions and involuntary replacement of damaged equipment do not avoid applicability o NSPS under 40 CFR 60.15 when a unit would have been reconstructed. Therefore, it would be inconsistent to establish such a concept under nonattainment NSR. In addition, 40 CFI 60.15, which governs how the reconstruction rule will apply in the affected NSR programs (*see e.g.*, 40 CFI Part 51 Appendix S, section II. A(12)), allows the Administrator, in paragraph (f), some case-by-case discretion in determining when a reconstruction would occur. Thus, no specific exemptions such as those suggested appear warranted at this time.

K. Exclusions

In September, EPA proposed to exclude "routine maintenance, repair and replacement" from the category "physical change" which appeared in the proposed PSD and nonattainment definitions of "major modification." At the same time EPA proposed to exclude the following events from the category "change in method of operation," unless previously limited by enforceable permi conditions: (1) a fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 197 (ESECA) (or any superseding legislation or due to a natural gas curtailment plan under the Federal Power Act; (2) a voluntary switch to an alternative fuel or raw material that the source prior to January 6, 1975, was capable of accommodating; (3) a fuel switch due to an order or rule under section 125 of the

Clean Air Act; (4) a switch to "refuse derived fuel generated from municipal solid waste" (RDF), and (5) a change in the ownership of a source.

EPA received few comments on the proposed exclusions. Certain commenters expressed reservations about the legal and policy basis of the RDF exclusion. Another commenter urged EPA to expand the exclusion for voluntary switches to an alternative fuel or raw material. Specifically, the commenter urged the Agency to drop the provisions which limited the exclusion to switches that would not require a change in permit conditions and to sources that were capable of accommodating the fuel or material before January 6, 1975. The commenter agreed with the position EPA took in the preamble to the 1978 Part 52 PSD regulations that Congress in enacting section 169(2)(C) intended that voluntary switches to an alternative fuel or raw material should be treated in the same way that they were being treated under section 111. *See* 43 FR 26396 (June 19, 1978). At the time Congress enacted section 169(2)(e), the regulations promulgated under section 111 excluded any such switch if the source could accommodate the fuel or material before the relevant NSPS applied to the source type. Whether a permit condition would restrict the switch was immaterial. *See* 40 CFR 60.14(e)(4) (1979). In view of this, the commenter argued that Congress intended the exclusion in the PSD and nonattainment regulations to look only at whether the source was capable of accommodating the fuel or material before those regulations first applied to it.

After considering the comments on the RDF exclusion, EPA has decided to promulgate it. The Resource Conservation and Recovery Act of 1974, 42 U.S.C. 3251 *et seq.*, firmly supports the exclusion. In that statute, Congress expressed a strong interest in the development and use of RDF. In addition, the exclusion has a sound policy basis, in view of the importance of reducing the nation's dependence on foreign oil.

In promulgating the exclusion, however, EPA has drawn it, by way of clarification, somewhat more tightly. It now excludes only a switch to RDF by a "steam generating unit." EPA intends that term to have the same meaning for the purposes of PSD and nonattainment NSR as it does for the purposes of the new NSPS for certain electric utility "steam generating units." For the NSPS definition of that term, see 40 CFR 60.41a (1979).

In response to the comment on the voluntary fuel and raw material switch provision, EPA has retained the language which limited it to sources which were capable of accommodating the fuel or material before January 6, 1975 (or December 21, 1976, for the Offset Ruling and 40 CFR 51.18; or July 1, 1979, for the construction moratorium) and the language which limited the exclusion to those not requiring a permit alteration. First, EPA disagrees that the cutoff date in the counterpart NSPS exclusion is analogous to the date the particular preconstruction permit regulations applied to a particular source. To the contrary, the NSPS counterpart is more broadly drawn; it focuses on the date the NSPS first applied to the *source type*. Second, EPA disagrees that the counterpart governs whether the NSR exclusions must ignore permit conditions. The NSPS program does not involve assessments of the impact of a source on air quality. In EPA's view, any switch to another fuel or raw material that would distort a prior assessment of a source's air quality impact should have to undergo scrutiny.

It should be noted that EPA has added a new clause to the exclusion for voluntary fuel switches. It provides that a switch which the relevant reviewing authority has already approved is not a "physical change" or "change in the method of operation" for NSR purposes. Obviously, a second evaluation of the air quality impact of the switch would be unnecessary.

The comment relating to voluntary switches has prompted EPA to add one more exclusion. It would exclude any increase in hours or rate of operation, as long as the increase would not require a change in any preconstruction permit condition established under the SIP (including PSD permits) after the relevant date of concern.

This exclusion stems largely from EPA's decision that the definitions of "major modification" should focus on changes in "actual emissions." While EPA has concluded that as a general rule Congress intended any significant net increase in such emissions to undergo PSD or nonattainment review, it is also convinced that Congress could not have intended a company to have to get a NSR permit before it could lawfully change hours or rate of operation. Plainly, such a requirement would severely and unduly hamper the ability of any company to take advantage of favorable market conditions. The emphasis of the relevant statutory provisions on "construction" strongly supports EPA's interpretation of Congress' intent. *See, e.g.*, section 165(a), 42 U.S.C. 7475. At the same time, any change in hours or rate of operation that would disturb a prior assessment of a source's environmental impact should have to undergo scrutiny.

Because of the absence of any significant comments on the other four exclusions, EPA has promulgated them as proposed.

L. Example of How the Definitions Work

The way in which the definition of modification works is best illustrated by an example. The example also demonstrates the relationship among a source's potential to emit, its actual emissions, and its allowable emissions.

In December 1980, a new source (Source A) that will emit SO_2 and PM files a PSD application to locate in an area that is attainment for SO_2 and PM. At maximum operating capacity including application of best available control technology, and assuming year-round continuous operation, the source can emit 700 tons of SO_2 per year. Seven hundred tons per year (tpy) is the source's physical potential to emit SO_2. Its physical potential to emit PM is 15 tpy. Provided that the 15 tpy of PM emissions is made federally enforceable, PM emissions will not be significant (*i.e.*, less than 25 tpy) and are, therefore, not subject to PSD review.

In the course of review, modeling reveals the SO_2 increment will be violated in the source's area of impact if it emits 700 tons SO_2 per year. The source, therefore, decides to limit its operation so as to decrease its emissions to 600 tons SO_2 per year. This reduction proves sufficient to eliminate the predicted violation. The source is issued a PSD permit that sets an SO_2 emissions limitation of 600 tpy, which reflects the revised source operation (approximately 20 hours a day, seven days a week). This emissions rate is the source's legal potential to emit. It is also the source's allowable emissions, since it is the emissions rate specified as a federally enforceable permit condition. *See e.g.*, § 52.21(b)(15)(iii).

During the first three years of operation, from March 1982 to March 1985, the demand for the source's product is less than anticipated. As a result, the source's actual emissions are 250 tpy during the first year and 300 tpy during the next two years.

In April 1985, another new source of SO_2 (Source B) proposes to locate in the area of impact of Source A. Consequently, in calculating its impact on ambient standards and its increment consumption, Source B is required to model the emissions of Source A. Under EPA's increment consumption policy (*see* Increment Consumption), Source

A's actual emissions should be modeled. Because Source A has an individually-tailored PSD permit, the definition of actual emissions allows the reviewing authority to presume that the allowable emissions in Source A's PSD permit reflects its actual emissions, unless the reviewing authority or source applicant has reason to believe that allowable emissions are not representative of actual source emissions.

In the case of Source A, allowable emissions, in fact, differ from actual emissions. Assuming that the reviewing authority is aware of this difference as a result of its periodic assessment or because Source B has presented this information in its application, Source A is modeled at its actual emissions rate representative of normal source operation during a two-year period preceding the date of concern. In this case, the date of concern would be approximately the date Source B submits its application. The reviewing authority should, therefore, look to the two-year period preceding that date unless that period of time was atypical of normal source operation. For Source A, the two-year period preceding Source B's application can be considered representative of normal source operation. Source A's actual emissions during that period, on an average annual basis, are approximately 300 tpy. The modeling of increment consumption for Source B should assume that emissions rate for Source A.

Unless Source A's permit is revised at this point to reflect its actual emissions rate of 300 tpy, Source A could attempt to use the decrease in its actual emissions in the future to offset a future emissions increase of its own. This would result in a large net increase in actual emissions for the area which could violate the applicable PSD increment. The potential problem of double counting of emissions decreases is discussed in more detail in Increment Consumption.

Assume that in June 1987, Source A decides to modify its facility. Demand for its product has increased and Source A wants to add a new emissions unit that will emit 60 tpy SO_2. In addition, Source A plans to increase the hours of operation at the units which began production in March 1982, to result in an actual emissions increase of 75 tpy at those units. If no contemporaneous decreases have occurred, both changes will result in significant net increases in actual emissions. Both changes then qualify as modifications. The addition of a new unit is a physical change. The increase in hours of operation is a change in the method of operation, assuming that the reviewing authority revised Source A's permit to reflect its actual emissions of 300 tpy at the time Source A's actual emissions were used by Source B in modeling increment consumption.

If Source A was able to decrease sufficiently its actual emissions at another unit at the source, it would be able to avoid PSD review for one or both modifications. Assume, for example, that in April 1986, Source A applied additional control equipment and decreased actual SO_2 emissions across the facility by 100 tpy. In June 1987, Source A can use those decreases to offset its proposed contemporaneous increases provided the decreases are made federally enforceable. If Source A's proposed increase in hours of operation for the units which began operation in March 1982 would result in an emissions increase of 75 tpy and the emissions from the proposed new unit are 60 tpy, Source A can use its 100 tpy decrease to avoid PSD review for both changes. Seventy-five tons of the decrease can be used to offset the increase in hours of operation and 25 tons of the decrease can offset 25 tons of the increase due to the new unit. Since the net emissions increase of 35 tons is not significant, it would not be a major modification requiring PSD review.[12]

Suppose Source A then plans to increase its emissions by 150 tpy in November 1990 and to decrease emissions by 80 tpy in February 1989. The increases and decreases since April 1986 are all contemporaneous because they occurred within the same five-year period. Now, assume Source A revises its permit to reflect only 50 tons of the 80-ton decrease in February 1989. Source A can receive credit for only 50 tons of the 80-ton decrease, since only this amount was made federally enforceable. However, Source A does receive credit for the April 1986 decrease of 100 tpy, assuming that decrease was made federally enforceable at the time of the June 1987 increase, or is made federally enforceable prior to commencement of construction on the November 1990 increase. Source A's total creditable decreases are then 150 tpy. Its increases are 135 tpy in June 1987 and 150 tpy in November 1990, for a total increase of 285 tpy. The net emissions increase is 135 tpy, which is significant for SO_2. Source A must get a PSD permit for the change leading to the 150 tpy increase in November 1990. However, it is not required to get a PSD permit for the June 1987 increases.

If, from March 1982 to March 1985, Source A had exceeded its allowable rate of 700 tpy, Source A could not receive full credit for its April 1986 decrease. For example, assume Source A's actual emissions from March 1982 to March 1986 were 800 tpy, 100 tpy over its allowed rate. None of the 100 tpy reduction in April 1986 would then be creditable. The amount of Source A's creditable decrease could also be reduced if the designation of the area where Source A is located were changed from attainment to nonattainment in March 1985 and Source A became subject to a new, more stringent SIP requirement in March 1986. If, for example, the SIP required Source A to reduce emissions from 700 to 600 tpy by December 1988, none of the 100 tpy decrease in April 1986 would again be creditable.

XI. De Minimis Exemptions

In the *Alabama Power* decision, the court indicated that emissions from certain small modifications, and emissions of certain pollutants at new sources, could be exempted from some or all PSD review requirements on the grounds that such emissions would be *de minimis*. In other words, the Administrator may determine levels below which there is no practical value in conducting an extensive PSD review. The court also indicated that the Agency could establish exemptions based on administrative necessity (e.g., the inability of reviewing authorities to provide the necessary work force to properly review a very large number of permit applications). The September 5 proposal incorporated the *de minimis* concept and requested comments on the approach taken. At that time, the Administrator noted that because of the urgency associated with the proposal, the *de minimis* numbers published were not supported by extensive analysis, and that a more thorough analysis would be undertaken prior to promulgation.

The proposal included two tables, one for defining significant emissions changes (in tons per year) and one for defining significant air quality changes (in micrograms per cubic meter). Values lower than those in the proposed tables were recommended as being *de minimis*. These tables, with respect to criteria pollutants, were generally based on the "significance" levels published in the preamble to the June 19, 1978 PSD regulations (43 FR 26398) and in the Offset Ruling (44 FR 3283). These significance levels in turn were derived from the Class I increment values listed

[12] Under the provisions of 40 CFR Part 51 Appendix S, 40 CFR 51.18(j), and 40 CFR 52.24, the emissions increases at Source A would probably be subject to review as modifications, notwithstanding the contemporaneous decreases at the source.

in Part C of Title I of the Clean Air Act. For noncriteria pollutants, a similar approach was taken: the Agency extrapolated emissions rates from documented air quality guideline numbers, where available.

In the proposal, the tables were presented as preamble guidelines to be used in the following manner. For PSD, any new source subject to review was to be analyzed for the application of BACT for each pollutant whose emissions would exceed the value in Table 1. In addition, an air quality analysis to determine the impact of these pollutants was required. For modifications, any pollutant for which the source was major and for which there was a contemporaneous net increase equal to or greater than the applicable value(s) in Table 1 would trigger PSD review of the modification; as in the case of new sources, BACT and air quality impact analyses were required for each pollutant whose net emissions increased by greater than a *de minimis* amount. Table 2 was proposed to provide an exemption from air quality impact analysis (including monitoring) for those sources and modifications which could demonstrate that their maximum expected air quality impact would be less than the values listed. Sources, including modifications, claiming to be exempt from reviews on the basis of *de minimis* emissions would be required to so notify the Administrator. The *de minimis* requirements also would apply to nonattainment sources, but would be restricted to the pollutant(s) for which the area is nonattainment.

The Agency received extensive comments on the proposed *de minimis* approach. In all there were 121 comments addressing this issue. While there was almost universal endorsement of the concept, a large number of commenters (65) criticized the proposed values as being too low. Some of these commenters stated that there was a lack of support for the numbers presented and felt that the emissions table was more restrictive than the table of air quality concentrations; others claimed that the low *de minimis* levels made the applicability of the review process inequitable for modifications in comparison to new sources. A consistent theme was that the proposed values would necessitate unproductive review in terms of environmental benefit while consuming applicant and reviewing authority resources. Although there were suggestions concerning how big the emissions numbers should be (100 tons per year was a popular choice), little specific guidance was given on how to develop alternative numbers. Suggestions generally were limited to using various percentages of the national ambient air quality standards or the amount of existing emissions. One commenter did suggest the use of an equation that accounted for variability in stack height.

Only one commenter criticized the *de minimis* levels for being too high. This commenter also believed that exemptions from review because of emissions less than the *de minimis* rate should not be automatic, but should be allowed only after a case-by-case review of source impact. In addition, the commenter stated that in areas where the increment is almost entirely consumed, sources should be subject to PSD review for any increase in emissions.

A frequently addressed aspect was the perceived need to incorporate any *de minimis* values in the regulations, as opposed to leaving them as guidelines in the preamble. Forty-eight of fifty-six commenters favored such a change. The general concern was that since the preamble is omitted from the Code of Federal Regulations, the regulations as written would appear to be ambiguous as to the term "significant." Those that favored leaving the tables as guidelines did so generally to provide more flexibility either for sources to demonstrate that they should be exempt or for states to develop alternative *de minimis* values.

There were several other meaningful comments. Sixteen commenters recommended that *de minimis* coverage be limited to criteria pollutants. Eighteen commenters contended that the need to accumulate *de minimis* changes was burdensome, environmentally unnecessary, and should be dropped; some questioned the legislative basis for this requirement. Several commenters cited the difficulty, if not impossibility, of monitoring for all regulated pollutants. These commenters were especially concerned regarding monitoring for noncriteria pollutants, indicating that the requisite technology was not available in some cases. Other commenters questioned how the term "no impact," which is used in the regulations to protect Class I areas, relates to the Table 2 *de minimis* values.

Mindful of the comments received, the Administrator has undertaken a reassessment of the *de minimis* issue. This reassessment is decribed in two documents. One is a report entitled "Impact of Proposed and Alternative *De Minimis* Levels for Criteria Pollutants," EPA–450/2–80–072, and the other is a staff paper entitled "Approach to Developing *De Minimis* Values for Noncriteria Air Pollutants." These are available for examination in the rulemaking docket. In addition, copies may be obtained by writing to the Air Information Center, U.S. EPA Library Services, MD–35, Research Triangle Park, NC 27711.

Obviously, a significant part of the reassessment involved the use of reasonable judgment. The task requires consideration of an area in which not only is data limited, but criteria for decision making is almost non-existent. The first task of the reevaluation was to identify the basic objectives to be met in selecting *de minimis* values. The primary objectives identified were: (1) provide effective Class I area protection; (2) guard against excessive "unreviewed" consumption of the Class II or III increments; and (3) assure meaningful permit reviews. "Meaningful" in this context implies that there would be a possibility of obtaining useful air quality information or obtaining greater emission reductions as a result of BACT analysis than would be expected from normal state permit or NSPS/NESHAP processing.

The proposed *de minimis* air quality values, which stemmed from the legislated Class I increments, caused concern for two reasons. First, if a modification occurs near enough to a Class I area, almost any *de minimis* emissions level could impact the area. Thus, proximity rather than emissions level appears to be more important in Class I area protection. Second, the general imposition of Class I criteria on the review process for Class II and III areas may be overly stringent. These concerns were examined as part of the *de minimis* reassessment.

As a result of this examination, the Administrator has decided that higher *de minimis* emissions rates than those used in the proposal could apply to review of sources which would not construct within a specified distance of a Class I area. However, a proposed source or modification that would construct close to a Class I area must be prepared to demonstrate for each regulated pollutant that it would emit that it would not have a significant impact on such area (defined as one microgram per cubic meter ($\mu g/m3$) or more, 24-hour average), even if the proposed emissions increases are below the applicable *de minimis* threshold. The effect of this change is to require less review for many sources through higher *de minimis* values (compared to the proposal), while adding a limited air quality analysis requirement for only a few sources. Such a change is consistent with the objectives of protecting Class I

areas while limiting PSD review to projects with significant impact.

There were three basic alternatives available for specifying *de minimis* cutoffs—one based solely on air quality impact, one based solely on emissions rate, and one based on a combination of these, such as was proposed on September 5. The Administrator has chosen to specify *de minimis* cutoffs in terms of emissions rate for applicability, BACT and air quality analysis purposes, with no provisions for case-by-case demonstration of a source's air quality impact. This is a departure from the proposal in that, as proposed, a source could avoid air quality analysis requirements for a given pollutant by demonstrating that it would produce a maximum impact less than the air quality concentrations listed for that pollutant. An air quality concentration *de minimis* level for each pollutant for which measurement methods are available is included in the regulations only for the purpose of providing a possible exemption from monitoring requirements.

This approach has been adopted for several reasons. First, the Congress specified emissions rates, not projected air quality impacts, in the Clean Air Act as the criteria for determining which sources are major and therefore subject to PSD review. Moreover, the court, in the *Alabama Power* decision, continually refers to emissions rate rather than air quality concentration in its discussion of the *de minimis* issue. Therefore, it would be inconsistent with the existing guidance to abandon the emissions rate concept.

Second, if applicability decisions depended on confirming a demonstration by the source that its impact would be less than a given air quality level, it is the Administrator's opinion that the review process would become excessively complex and greatly increase the resources needed by reviewing authorities to carry out the program. In addition, such an approval would create and atmosphere of uncertainty as to whether individual sources needed to apply for a permit or not, and could lead to uneven application of the regulations from state to state. Third, the task of establishing *de minimis* air quality levels for noncriteria pollutants, with proper consideration of threshold levels and factors of safety (if any), is very complex and could not be done in the time available.

Finally, given the inclusion of a *de minimis* exclusion for monitoring, it serves little purpose to have a separate table to permit an exclusion from the remaining air quality impact analysis requirement. (A separate table would be required because monitoring capability and concern for potential effects are unlikely to be associated with the same air quality concentrations.) Besides making the regulations more complicated, this resultant demonstration necessary to earn an exemption from air quality impact analysis would in itself *be* an air quality impact analysis.

In analyzing the basis for *de minimis* emissions rates, it was apparent that two distinct classes of pollutants were involved. The first consists of the criteria pollutants for which extensive health and welfare information has been developed and documented in the respective criteria documents. The other class consists of the noncriteria pollutants for which, as the name implies, no criteria on ambient effects exist. Rather, these pollutants are covered by either New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP), both of which are based on a national emissions standard, rather than an air quality management approach. That is, the regulations developed pursuant to both these legislative requirements generally specify emissions limitations and/or equipment performance standards as opposed to threshold air quality levels that must be achieved as for the criteria pollutants. Thus, it appeared reasonable to develop *de minimis* cutoffs from separate perspectives—to base criteria pollutant *de minimis* emissions cutoffs on air quality "design values" and to base the noncriteria pollutant *de minimis* values on the emissions rates embodied in the NSPS and NESHAP.

The first step in developing *de minimis* emissions rates for the criteria pollutants, therefore, w[illegible] the establishment of air quality "design values." Such design values were then converted to emission rates in accordance with EPA modeling procedures,[18] using data on sources permitted under the PSD program. The latter provided modeling parameters associated with sources of the type expected to be most affected by the *de minimis* requirements. Ambient concentations repreaenting percentages of the primary 24-hour air quality standard, as well as percentages of the Class II increment, were evaluated for particulate matter (PM) and sulfur dioxide (SO_2). Similarly, various percentages of the primary standard for the other criteria pollutants were examined.

The primary standard was chosen as the basis for design values because, except for PM and SO_2, none of the criteria pollutants have a secondary standard that is different than the primary standard. The 24-hour standard instead of the annual standard was used for PM and SO_2 since short term rather than the long term impact tends to be the controlling factor in determining whether air quality increments are exceeded. In addition, levels higher than five percent of the primary standard were not seriously considered because that percentage equates to approximately 35 percent of the TSP Class II increment. The Administrator does not believe that a source which, due to its own emissions, could potentially consume more than that amount of increment should be exempt from review.

Two factors had an important influence on the choice of *de minimis* emissions levels within the resulting range of annual emissions rates. The primary one was the cumulative effect on increment consumption of multiple sources in an area each making the maximum *de minimis* emissions increase (thereby going unreviewed under PSD at the time of the change). The other, and secondary one, was the projected consequence of a given *de minimis* level on administrative burden. To determine the cumulative effect on increment consumption expected from several sources, all making maximum *de minimis* increases (a rather unlikely event) in the same area, actual source distributions in the Dayton, Ohio, area were used. Dayton was chosen because it is a fairly representative industrialized community, and source data suitable for modeling was readily available. To check the impact of the various *de minimis* levels on administrative burden, data from past permitting experience were again used, in this case to prepare curves showing the number of sources expected to require review at various *de minimis* emissions levels. A description of these analyses is found in the *de minimis* report on criteria pollutants cited earlier.

As a result of the reevaluation, the Administrator has decided to use four percent of the 24-hour primary standard as a design value for both PM and SO_2. These ambient levels correspond to emissions rates of 25 tons per year for PM and 40 tons per year for SO_2 (except for lead, all emissions rates predicted from the modeling for criteria pollutants were rounded to the nearest five tons).

[18] Guidelines for Air Quality Maintenance Planning and Analysis, Volume 10 (Revised): Procedures for Evaluating Air Quality Impact of New Stationary Sources, OAQPS No. 1.2-022R, October 1977.

Four percent of the lead standard was also used, yielding an emissions rate of 0.6 tons per year. The emissions rate for carbon monoxide (CO) in all cases was greater than 100 tons per year, the limit set in the Clean Air Act to define major for many source categories. Therefore, as proposed, the *de minimis* emissions rate for CO is established at 100 tons per year.

Because the nitrogen dioxide standard is expressed only as an annual average, a factor of two percent was used to determine the design value. There were two reasons for this decision. First, for a given level of emissions, a predicted annual concentration will be smaller than a short-term value. Conversely, therefore, a lower percentage for the annual standard than for a shorter term standard is indicated if one is to maintain a reasonably consistent rationale for emissions rates. Second, the emissions rate corresponding to two percent of the standard is 40 tons per year, which is comparable to the rate established for SO_2. Both these pollutants are frequently emitted from the same source, in roughly equivalent amounts; for example, a typical power plant meeting the NSPS with low sulfur coal would emit about 1300 tons per year of nitrogen oxides and about 1500 tons per year of SO_2.

Finally, models for use in establishing a relationship between individual source hydrocarbon (VOC) emissions and ozone concentrations are not presently available. Thus, it was not possible to model an emissions rate from an air quality design value. However, in view of the link between VOC and NO_x emissions in the formation of ozone, the emissions rate for VOC was also set at 40 tons per year.

It should be recognized that several sources or modifications can be allowed in the same area even though each might consume up to four percent of the standard (about 16 percent of the Class II increment for SO_2 and about 28 percent for PM). This is because the source specific concentration occurs in only a limited area (often one point) and the temporal and spatial conditions which lead to maximum consumption by one source are seldom the same for other sources that may be making similar *de minimis* changes. To reinforce this understanding, a modeling analysis of 37 sources in the Dayton area was conducted. The maximum aggregate increment consumption projected to occur as a result of all major sources each making a *de minimis* emissions increase equal to 40 tons per year (*e.g.*, that for SO_2) was less than 1.5 $\mu g/m3$ on a 24-hour basis. While representative of only one set of conditions, this result could probably be expected in most industrialized areas.

Excessive increment consumption is unlikely, given the safeguards existing in the regulations. Although such sources would not get PSD permits, they do not go unreviewed. Most, if not all, will be permitted under ongoing state NSR programs pursuant to 40 CFR 51.18. Moreover, their contribution to increment consumption will be evaluated either by the next major source undergoing PSD review, or during the periodic assessment of source growth. Nevertheless, in atypical situations there might still be concern with the *de minimis* levels causing accelerated increment consumption. This can be controlled by a state, upon taking the program, through the establishment of smaller *de minimis* levels.

To determine a proximity cutoff that gives assurance of protection of Class I areas, a modeling analysis was performed to identify the effect of the *de minimis* emissions levels on such areas using Volume 10 screening procedures. For the purpose of this analysis, the effect of varying stack height and meteorology, as well as the influence of terrain features, was considered. Significant impact was taken to be one $\mu g/m^3$, 24-hour average. The results indicate that sources locating more than 10 kilometers from a Class I area would not have such an impact as a result of making *de minimis* changes. Therefore, the regulations promulgated here require that any new or modified major stationary source within that distance from a Class I area will be subject to review if the source would have an impact on the area equal to or greater than one $\mu g/m^3$, 24-hour average. It must be pointed out that while the preceding responds to those commenters concerned about how to judge whether a source has "no impact" on a Class I area, the analysis of impact on such an area from major sources subject to PSD review must be done on a case-by-case basis. Further, such sources may be subject to an evaluation by the appropriate Federal Land Manager as described in the regulations.

Noncriteria pollutant emissions rates were developed from the existing emission standards (NSPS and NESHAP). In general, a fraction of the applicable standard was used. In the Administrator's judgment, since the NSPS represents the best adequately demonstrated control technology on a nationwide basis, and the NESHAPs are established with an ample margin of safety to prevent unreasonable risk to the public health from hazardous pollutants, a small percentage of these standards would, for PSD purposes, prevent a significant change from escaping review.

Levels generally representing 20 percent of a NSPS emissions standard and, because of their greater impact on health, ten percent of a NESHAP emissions standard, were evaluated. The air quality impacts of the resulting NSPS emissions rates were then calculated in a manner similar to that used for the criteria pollutants. These concentrations were compared to available health and welfare data to assure that significant adverse effects were avoided. In the case of fluorides, this check resulted in a reduction of the emissions rate originally indicated. No adjustment based on resultant effect was made for the hazardous pollutants since the NESHAP emissions rate, as noted above, is itself intended to protect the public health with an ample margin of safety; therefore, ten percent of such a value is in the Administrator's judgment sufficiently stringent for use as a *de minimis* level.

A brief discussion of the rationale for each noncriteria pollutant emissions rate is given below. For more information, see the staff paper cited earlier.

Hazardous Pollutants (NESHAP):

Asbestos—Reevaluation of existing data indicates that trying to establish a quantitative link between emissions and potential effects is not possible. No level of exposure can be presumed *de minimis*. Therefore, a theoretical *de minimis* emissions rate of zero was considered. Such a value is not practical, however, since changes of any kind at sources using materials containing even traces of asbestos could trigger review regardless of the amount of asbestos emitted. Therefore, an estimate was made of the emissions from well controlled sources from which asbestos can be emitted. Although data is very limited, rough estimates of emissions from four source categories were developed. Three categories are covered by the NESHAP regulations: asbestos milling, manufacturing using asbestos in the process (e.g., textiles, asbestos tile), and asbestos asphalt manufacture. Rock crushing, a fourth category not covered by the NESHAP, was also examined. Emissions rates from these four categories, using available data, were respectively 0.2 tons per year (TPY), 0.07 TPY, 0.04 TPY, and 0.06 TPY. Because asbestos is carcinogenic, a conservative approach to establishing the *de minimis* emissions rate has been taken. The *de minimis* level is based on a source category

which has relatively small asbestos emissions, and which includes the majority of asbestos emitting sources—manufacturing operations using asbestos. Therefore, the promulgated asbestos *de minimis* rate is 0.007 TPY, based on ten percent of the emissions estimated from asbestos manufacturing sources.

Beryllium—The NESHAP emissions rate is ten grams per day or 0.004 tons per year. Ten percent of this yields a *de minimis* emission rate of 0.0004 tons per year.

Mercury—The NESHAP emissions rate is 2300 grams per day which equates to approximately one ton per year. At ten percent, the promulgated *de minimis* emissions rate is 0.1 tons per year.

Vinyl chloride—The NESHAP standard is expressed in parts per million of the effluent stream. It was therefore necessary to assume model plant characteristics in order to develop expected emissions from a well controlled plant. As in the case of asbestos, the Administrator believes that it is prudent to base these calculations on a small model plant considering the suspected carcinogenicity of this pollutant. Such plants, well controlled, emit about 10 tons per year. Based on this value, the promulgated *de minimis* emissions rate is one ton per year.

NSPS Pollutants:

Fluorides—The proposed *de minimis* emissions rate for fluorides was extremely conservative, and was strongly criticized as being too low by several commenters. Upon reevaluation, the Administrator agrees with the comments. A *de minimis* emissions rate based on the NSPS for aluminum plants is 30 tons per year—a well controlled, moderate sized, plant emits about 150 tons per year of fluorides. At a rate of 30 tons per year, the predicted maximum 24-hour ambient concentration is approximately ten micrograms per cubic meter. That concentration is about ten times the level that has been observed to produce effects on vegetation (about one microgram). In order to limit the potential for such damage, a *de minimis* emissions rate of three tons per year, corresponding to a one microgram impact, is promulgated.

An alternative would have been to base the emissions rate on the NSPS for phosphate fertilizer plants. Fertilizer plants typically emit much less than aluminum plants (i.e., about two tons per year controlled). A 20 percent *de minimis* value would then be less than 0.5 tons, which is unrealistic in view of other sources such as aluminum plants. Moreover, changes at a fertilizer plant that resulted in a fluoride emissions increase of 0.5 tons per year would probably get reviewed under state new source review and/or NSPS requirements.

Sulfuric Acid—A model plant of 1300 tons per day of production was used. The NSPS emissions limit is 0.15 pounds of sulfuric acid per ton of product processed. Thus, the model plant would emit about 35 tons per year. This yielded a *de minimis* emissions rate of seven tons per year using the 20 percent factor.

Total Reduced Sulfur, Reduced Sulfur—These pollutant classes include hydrogen sulfide (H_2S) and are regulated primarily to avoid nuisance (odor) problems. Total reduced sulfur (TRS) emissions are based on a representative kraft pulp mill (900 tons of pulp per day) which at 20 percent yields a *de minimis* emissions rate of 10 tons per year. Similarly, using a model refinery of about 100 long tons per day, the reduced sulfur (RS) compound emissions rate is 10 tons per year.

(The emissions rates calculated on the above model plants were 8.3 tons per year for TRS and 9.4 tons per year for RS. Both values were rounded to 10 tons per year for administrative purposes.)

Hydrogen Sulfide—Regulated under the refinery NSPS only. Specified as one thirtieth of reduced sulfur emissions, in major part as a check on control efficiency. Since concern, at the NSPS emissions levels, for TRS, RS, and H_2S is the same (nuisance rather than health impact) the *de minimis* emissions rate for H_2S alone is set at ten tons per year.

Methyl Mercaptan, Dimethyl Sulfide, Dimethyl Disulfide, Carbon Disulfide, Carbonyl Sulfide—*De minimis* emissions rates were proposed for these compounds. However, none of them are individually regulated under the Act. Rather, they are described as constituents of either TRS or RS. Therefore, since *de minimis* emissions rates are promulgated for TRS and RS, individual *de minimis* for the five compounds have been dropped.

The complete list of the emissions levels promulgated today, and where applicable, the *de minimis* air quality design values from which they are derived, is given below in Table A:

Table A.—*De Minimis Values*

Pollutant	De Minimis emissions rate (TPY)	Design air quality value (average time) (μg/m³)
Carbon monoxide	100	
Nitrogen oxides	40	2 (annual).
Sulfur dioxide	40	14.6 (24-hour).
Total suspended particulates.	25	10.4 (24-hour).
Ozone (volatile organic compounds).	40	
Lead	0.6	0.06 (3 month).
Asbestos	0.007	
Beryllium	0.0004	
Mercury	0.1	
Vinyl chloride	1.0	
Fluorides	3	
Sulfuric acid mist	7	
Total reduced sulfur (including H_2S).	10	
Reduced sulfur (including H_2S).	10	
Hydrogen sulfide	10	

The air quality design values are not included in the regulations. *De minimis* emissions levels are included for use in defining the term "significant." As in the proposal, these values determine the need to review modifications and determine which pollutants require BACT and air quality impact analyses for any new source or modification requiring review.

The Administrator does not believe that the promugated *de minimis* levels will produce an extraordinary administrative burden on reviewing authorities. Based on the data available, it is estimated that approximately 700 more sources will be subject to PSD review annually, all for small modifications not heretofore reviewed.

The regulations also include a list of air quality concentrations for each pollutant as criteria for exempting sources from the monitoring requirements at the discretion of the reviewing authority. Table B summarizes the applicable air quality values by pollutant type.

Table B.—*Monitoring Exemption*

Pollutant	Air quality value (averaging time) (μg/m³)
Carbon monoxide	575 (8-hour).
Nitrogen dioxide	14 (24-hour).
Sulfur dioxide	13 (24-hour).
Total suspended particulates	10 (24-hour).
Ozone	(1)
Lead	0.1 (24-hour).
Asbestos	(2)
Beryllium	0.0005 (24-hour).
Mercury	0.25 (24-hour).
Vinyl chloride	15 (24-hour).
Fluorides	0.25 (24-hour).
Sulfuric acid mist	(2)
Total reduced sulfur (including H_2S).	10 (1-hour).
Reduced sulfur (including H_2S)	10 (1-hour).
Hydrogen sulfide	0.023 (1-hour).

[1] All cases where emissions of VOC are less than 100 tons per year.

[2] No satisfactory monitoring technique available at this time.

Several Table B values are somewhat different from the design air quality numbers shown in Table A. This is because the Table B values are based on the current capability to provide a

meaningful measurement of the pollutants. The values promulgated represent five times the lowest detectable concentration in-ambient air that can be measured by the instruments available for monitoring each pollutant. The factor of five was chosen after reviewing test data for the various methods considered reasonably available. The decision was based in part on considerations of instrument sensitivity, potential for sampling error, problems with instrument variability (*e.g.*, zero drift) and the capability to read recorded data. For a more thorough discussion of this determination, see the memorandum from K. Rehme to W. Peters dated May 20, 1980, which is available in the rulemaking docket and from the address given for the other reports.

There also are several changes in the use of Table B from the Table 2 proposed on September 5. First, a source deemed subject to review may claim the *de minimis* air quality impact exemption from only the monitoring requirement for the reasons noted earlier. Next, under the proposal, a source had to demonstrate that its ambient impact would be *de minimis* to obtain an exemption from monitoring. As promulgated, the regulation allows a source to be exempted from the preapplication monitoring requirement if it shows either that existing air pollution in the source impact area or its projected impact in the affected area is *de minimis*. In most cases, little is to be gained from preconstruction monitoring in situations where either condition applies.

Finally, because there will be situations where monitoring will be necessary even if modeling predicts *de minimis* conditions, the exemption is not automatic but rather must be with the approval of the reviewing authority. For example, Table B values should not be used when (1) there is an apparent threat to an applicable PSD increment or NAAQS based on modeling alone or (2) when there is a question of adverse impact on a Class I area. Questions of adverse impact on a Class I area are to be decided on a case-by-case basis with the objectives of the affected Federal Land Manager in mind.

Some of the suggestions made in the comments have not been adopted. For the reasons stated earlier, many of the *de minimis* values have been increased. The automatic exemption on the basis of emissions rate is retained, although the exemption from monitoring has been made discretionary. The Administrator believes that a clear indication of applicability is necessary. It is not reasonable to expect a potential applicant to have continuous knowledge of the status of increment consumption and thus know when an application is required and when it is not. Nor have the *de minimis* values been promulgated as a guide only, with a screening review of all sources made mandatory as suggested by one commenter. The Administrator does not believe that there is a substantial programmatic benefit to be derived from such a stringent requirement.

Accumulation of *de minimis* values has not been dropped, because for most pollutants the promulgated *de minimis* emissions levels are now substantially higher than those proposed. The suggestion to allow sources with greater than *de minimis* emissions to make a showing that their air quality impact was *de minimis* and escape review was considered and then rejected. The higher emissions levels promulgated will offer much of the requested relief. Moreover, such an approach would not streamline the review process (*i.e.*, a detailed air quality analysis would still be necessary), and several sources with taller stacks might avoid review and the BACT requirement. Variations in actual impact because of stack height can be a factor in the BACT review. Similarly, an equation considering stack height to determine the *de minimis* emissions rate cutoff has not been promulgated. It is questionable whether such an equation could be developed for application nationwide that would be any less judgmental than the fixed *de minimis* emissions rates promulgated. Moreover, that approach would be little more than a case-by-case applicability assessment which the Administrator believes is inadvisable for reasons already described.

Other suggestions not accepted were to raise the *de minimis* emissions levels to 100/250 tons per year for the criteria pollutants, and to limit the *de minimis* concept to only the criteria pollutants. In developing an approach to defining *de minimis* for PSD purposes and consequently calculating the specific *de minimis* values under the guidance given within the Act and *Alabama Power*, emissions levels as high as 100 tons per year could not be justified for most criteria pollutants. Use of the *de minimis* concept with respect to only the criteria pollutants suggests that any increase (i.e., a zero *de minimis* value) would be significant for noncriteria pollutants and must be reviewed. As mentioned earlier, a zero *de minimis* is not practical for this program.

XII. Geographic and Pollutant Applicability

A. Background

Alabama Power held that in determining the applicability of PSD review, EPA must look to whether a source locates in an area to which Part C of the Act applies, rather than to the impact the source would have upon such an area. Accordingly, EPA proposed on September 5 to apply PSD review to a source if the source locates in an area designated attainment or unclassifiable for a pollutant which the source emits in major amounts. Each pollutant emitted by the source would be subject to PSD review, unless the pollutant was one for which an area is designated nonattainment and the source emitted that pollutant in major amounts. A modification to a source would be subject to PSD review under the September 5 proposal if it would result in a significant net increase in the emissions of any regulated pollutant for which the source is major and for which the area is designated attainment or unclassifiable. In addition, EPA proposed on September 5 to apply PSD review to a source or modification that would significantly affect an area in another state designated as attainment or unclassifiable for a pollutant for which the source or modification would be major. *See* 44 FR 5190–41, 51949 (§ 51.24(i)(2)), 5193–54 (§ 52.21(i)(8)).

On January 30, 1980, EPA stated that it intended not to apply PSD review based solely on interstate impact, because the court's final interpretation of the Act in *Alabama Power* suggested that PSD review was not appropriate in such circumstances. EPA also noted that under its September 5 proposal, a source or modification would be exempt from PSD review if it emitted in major amounts only pollutants for which an area had been designated nonattainment. EPA solicited comments on whether this exclusion should be retained, as well as on its proposal to delete PSD review based solely on interstate impacts. *See* 45 FR 6803 (January 30, 1980).

B. PSD Applicability

After further evaluation of its proposed approach, and consideration of the comments submitted in response to the September 5, 1979, and January 30, 1980, notices (see discussion below), EPA has decided to modify the September 5 proposal somewhat. Under today's action, except with respect to nonattainment pollutants, PSD review will apply to any source that emits any pollutant in major amounts, if the source would locate in an area designated

attainment or unclassifiable for *any* criteria pollutant. If the source is subject to PSD review, then PSD review will be applied to each pollutant the source emits in greater than *de minimis* amounts, unless the area is designated as nonattainment under section 107(d)(1) for the particular pollutant. It should be noted that in order for PSD review to apply to a source, the source need not be major for a pollutant for which an area is designated attainment or unclassifiable; the source need only emit *any* pollutant in major amounts (i.e., the amounts specified in section 169(1) of the Act) and be located in an area designated attainment or unclassifiable for that or any other pollutant. Therefore, sources that are major only for pollutants for which an area is designated nonattainment will not be exempt from PSD review unless the source is located in an area which is designated nonattainment for all criteria pollutants or unless all of the regulated pollutants emitted by the source in greater than *de minimis* amounts are nonattainment pollutants.

The applicability of the PSD regulations to modifications mirrors that for new sources (*see* Modification). PSD review will apply to any modification to a source which emits any pollutant subject to regulation under the Act in major amounts, if the modification would result in a significant net increase in the emissions of *any* pollutant, and if the source is located in an area designated attainment or unclassifiable for any criteria pollutant. PSD review would not apply to any nonattainment pollutant. Unlike the approach proposed on September 5, in order for PSD review to apply, the modification need not increase emissions of a pollutant for which the source is major, nor need the source be major for a pollutant for which the area is designated attainment or unclassifiable.

EPA believes that this approach is required by *Alabama Power* and sections 165(a) and 169(1) of the Act. Section 165(a) states that "[n]o major emitting facility on which construction is commenced after the date of the enactment of [Part C of the Act], may be constructed in any area to which this part applies unless" the conditions set out in section 165(a) are met. *Alabama Power* held that this provision must be interpreted literally and that, in particular, EPA should focus on the *location* of the source, not its impact. *See* 13 ERC at 2012–2016. Today's action provides the necessary literal interpretation. A "major emitting facility" is defined in section 169(1) as a source which would emit at least 100 or 250 tons per year (tpy) (depending on the type of source) of "any" pollutant. This would cover both critiera pollutants, for which national ambient air quality standards have been promulgated, and non-criteria pollutants subject to regulation under the Act. Section 165 refers to an "area to which this part [part C] applies," which the Court in *Alabama Power* interpreted to mean "clean air areas," *i.e.* areas designated pursuant to section 107 as attainment or unclassifiable for a particular air pollutant 13 ERC at 2013. *See also* sections 161, 162, and 167 of the Clean Air Act. But neither section 165 nor section 169(1) links the pollutant for which the source is major and the pollutant for which an area is designated attainment or unclassifiable. Read literally, section 165(a) applies PSD preconstruction review to all sources that are major for any pollutant subject to regulation under the Act and locate in an area designated attainment or unclassified for any pollutant.

Section 165(a) also does not link review of a particular pollutant to the attainment status for that pollutant or limit review to pollutants for which a source is major. Rather, read literally, section 165(a) applies PSD review to *all* pollutants subject to regulation under the Act emitted by the source provided that the source is major for *some* pollutant and is located in a clean air area for some pollutant. However, implicit in *Alabama Power* and the structure of the Act is a recognition that where nonattainment pollutants are emitted in major amounts (i.e., where a source emits in major amounts a pollutant for which the area in which the source would locate is designated nonattainment), Part D NSR rather than Part C PSD review should apply to these pollutants (see below). PSD review does not apply to the nonattainment pollutants emitted by the source otherwise subject to review.

C. Nonattainment Applicability

On May 13, 1980, 45 FR 31307, EPA promulgated a final rule setting out the applicability of nonattainment review of new and modified sources. In brief, EPA clarified that the construction moratorium under section 110(a)(2)(I) and NSR under the Offset Ruling and section 173 apply to all major construction proposed in such areas. This applicability is unaffected by the particular air quality levels within the designated nonattainment area which would be caused or impacted by the proposed major source or major modification. States still are required under section 110(a)(2)(D) to review new or modified sources locating outside of nonattainment areas, but causing or contributing to a violation of an ambient air quality standard; however, review need not meet all of the nonattainment requirements under section 173 and the offset policy.

The current regulations concerning pollutant applicability in nonattainment areas have not been changed. These rules are different from the PSD pollutant applicability rules. Major sources are subject to review under the Offset Ruling, section 173, and the construction moratorium only if they emit in major amounts the pollutant(s) for which the area is designated nonattainment. In addition, only those nonattainment pollutants which the source emits in major amounts are subject to review or the construction moratorium. Similarly, only if a modification increases emissions of a pollutant for which the source is major and for which the area is designated nonattainment do nonattainment requirements apply. The basic rationale for these restrictions is that section 110(a)(2)(I), which contains the construction moratorium, restricts the construction moratorium to pollutants for which the source is major and for which the area is designated nonattainment. Since there is no requirement similar to the one in section 165(a) that subjects a source to review for all regulated pollutants it emits once it is subject to review for one pollutant, preconstruction review under the Offset Ruling and section 173 is restricted in the same manner as the construction moratorium.

For example, construction of a new plant with potential emissions of 500 tpy PM and 50 tpy SO_2 in an area designated nonattainment for both PM and SO_2 would be subject to nonattainment requirements for PM only, since the source is minor for SO_2. Similarly, modification of this plant resulting in a net increase in emissions of 50 tpy in SO_2 would not be subject to nonattainment requirements. See also examples (3), (4), and (7).

D. Case Examples

The following additional examples illustrate how applicability of PSD requirements will work under today's final regulations:

(1) Construction of a new plant with potential emissions of 500 tpy PM and 5(tpy SO_2 in an area designated attainment for both PM and SO_2 would be subject to PSD review for both PM and SO_2.

(2) Construction of the same plant as in example (1), but in an area designatec attainment for SO_2 and nonattainment for PM, would be subject to PSD review

for SO_2 and nonattainment requirements for PM.

(3) Construction of the same plant as in example (1), but in an area designated attainment for PM and nonattainment for SO_2, would be subject to PSD review for PM only. PSD review would not apply for SO_2, since SO_2 is a nonattainment pollutant.

(4) Construction of the same plant as in example (1), but in an area designated nonattainment for both PM and SO_2 would be subject to no PSD review and to nonattainment requirements for PM. This would be the case even if the SO_2 emissions would have an impact on a nearby Class I area for SO_2 or on an area located in another state which is designated attainment or unclassifiable for PM.

(5) Modification to the plant in example (1), where the plant is located in an area designated attainment for both PM and SO_2 resulting in a 30 tpy net increase in PM emissions, would be subject to PSD review for PM.

(6) Modification to the plant in example (1), where the plant is located in an area designated attainment for SO_2 and nonattainment for PM, resulting in increased emissions of 50 tpy in SO_2, would be subject to PSD review for SO_2. (It is a significant increase at a major source located in an attainment area.) But if the modification only were to increase the emissions of PM by 30 tpy, only nonattainment requirements would apply, since this is a modification of a major source for a nonattainment pollutant.

(7) Modification to the plant in example (1), where the plant is located in an area designated attainment for PM and nonattainment for SO_2, resulting in increased emissions of 50 tpy SO_2, would be subject to neither PSD review, nor the nonattainment NSR requirements. Nonattainment NSR would not apply since the 50 tpy increase in the nonattainment pollutant does not occur at an existing major stationary source for that pollutant. PSD does not apply since the only change is to a nonattainment pollutant. Instead, the general NSR under the SIP would typically apply to this pollutant, and the new emissions of SO_2 would be accommodated in the SIP's allowance for area and minor source growth.

(8) Construction of a new plant with potential emissions of 500 tpy hydrogen sulfide (H_2S) in an area designated attainment for PM would be subject to PSD review for H_2S. If, in addition, the plant had potential emissions of 50 tpy PM, PSD review would be applied to both H_2S and PM.

(9) Construction of a new plant with potential emissions of 500 tpy CO and 50 tpy H_2S in an area designated nonattainment for CO and attainment for SO_2 would be subject to PSD review for H_2S and to nonattainment requirements for CO. If this plant were later modified, resulting in a net increase in emissions of 30 tpy in H_2S, PSD review would apply for H_2S.

(10) Construction of a new plant with potential emissions of 500 tpy H_2S in an area designated nonattainment for all criteria pollutants would not be subject to either PSD review or nonattainment requirements. Part D applies only to criteria pollutants, and the area here is not subject to Part C, since it is not designated attainment or unclassifiable for any criteria pollutant.

E. Interstate Pollution

The September 5 proposal, in response to the *per curiam Alabama Power* decision issued on June 18, 1979, would have required PSD review for a major source locating or modifying in a designated nonattainment area only if such construction would substantially impact a clean air area in another state. In its final opinion issued on December 14, 1979, the court reversed its earlier position regarding the need for a PSD review of all interstate impacts to a neighboring state's clean air area. Under both rulings, PSD review would apply in all cases where the construction would take place in a clean area. Pursuant to the court's revised ruling in *Alabama Power*, EPA will not apply PSD review to a pollutant emitted by a source locating in an area designated nonattainment for that pollutant, even where the source would impact a PSD area in another state. Sixteen of the nineteen comments received by EPA supported this decision. Three commenters requested EPA to propose regulations to control interstate pollution pursuant to sections 110(a)(2)(E) and 161. EPA is now evaluating how best to control interstate pollution, and may propose regulations some time in the future.

F. Geographic Applicability for VOC Sources

On September 5, EPA proposed to delete the "36 hour rule," which subjected a source of volatile organic compounds (VOC) to review, if the source proposed construction within 36 hours pollutant travel time of an ozone nonattainment area. Pollutant travel time was to be calculated using wind conditions associated with concentrations exceeding the ambient standard for ozone. Most commenters agreed with the proposal to delete this requirement. One commenter who disagreed focused on the need for the rule as a means of determining which sources locating outside a designated nonattainment area should be subject to nonattainment review. Another argued that without the rule EPA will end up unnecessarily reviewing sources in remote rural areas whose impact on the ozone nonattainmnent problem is insignificant, since ozone is a regional problem.

For the reasons expressed on September 5 (44 FR 51940), EPA has decided to delete the 36 hour rule. The commenters' concerns are taken care of by the rules on geographic applicability for nonattainment areas, as set out at 45 FR 31307 (May 13, 1980). Thus, all major VOC sources locating in a designated ozone nonattainment area will be subject to review under section 173. Major VOC sources locating outside a designated nonattainment area will be subject to PSD review and will be required to monitor for ozone. If the monitoring indicates that the area of source location is nonattainment, then the provisions of the Offset Ruling or State plans adopted pursuant to section 110(a)(2)(D) of the Act shall apply until the area is redesiginated as nonattainment and a SIP revision has been approved. Of course, a source of VOC may choose to accept nonattainment review requirements immediately (i.e., LAER, offsets, statewide compliance of other sources under the same ownership) and conduct post-approval monitoring as presently permitted under the PSD regulations.

G. Response to Comments

Additional responses to comments regarding applicability of nonattainment requirements can be found at 45 FR 31307. Comments concerning interstate pollution and the geographic applicability of VOC sources, are responded to above.

With regard to PSD review, several commenters argued that EPA's approach would be overly complex and would impose great administrative burdens with few corresponding benefits to air quality. EPA does not agree. Applicability of PSD review as outlined above is required by the Act. Congress believed that such broad applicability was needed to adequately guard against significant deterioration in existing clean areas. EPA cannot restrict applicability and override Congressional intent simply because of an added administrative burden such applicability might impose. For similar reasons, EPA disagrees with the suggestion that it should restrict PSD review to only those pollutants that a source emits in major amounts.

Fourteen commenters argued that EPA should not apply PSD review to noncriteria pollutants, because the lack of NAAQS and increments for noncriteria pollutants indicates that Congress did not consider these pollutants to be able to cause significant deterioration and felt that the extent of harm by these pollutants has yet to be demonstrated. They claimed noncriteria pollutant sources are already subject to NSPS and NESHAP regulation. However, as other commenters have correctly noted, section 169(1) refers to sources with the potential to emit "any" pollutant above certain amounts. Moreover, section 165(a)(4) states that BACT must apply to "each polluant subject to regulation under this Act" emitted by a source. Neither of these provisions is limited to criteria pollutants. *See also Alabama Power*, 13 ERC at 2045.

Two commenters urged that if EPA decides to regulate sources with minor but significant emissions of criteria pollutants and sources of noncriteria pollutants, it should do so only if there already exists a SIP emission limit for the "minor" pollutants or only if section 111 or 112 (NSPS and NESHAP, respectively) has been made applicable after appropriate rulemaking to such sources of noncriteria pollutants. The difficulty with this approach is that the Act requires PSD review, regardless of whether another rule already applies to the source except in the case of nonattainment pollutants (see above). Moreover, the suggested approach could allow an unacceptably large number of sources to escape review, since many sources may not have an applicable SIP emissions limit or NSPS or NESHAP limit.

While most commenters endorsed the September 5 proposal that PSD permitting should be limited to instances where greater than *de minimis* changes in a major pollutant would occur, one commenter argued that *Alabama Power* did not restrict PSD applicability to modifications involving the pollutant(s) which the source emits in major amounts. This commenter claimed that section 111(a)(4) of the Act defines "modfication" as *"any* physical change in , or change in the method of operation of a stationary source which increases the amount of *any* air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." (Emphasis added.) As mentioned above in the Modification section, the Administrator agrees with this interpretation. Thus, today's final rule, with the exception of nonattainment pollutants, requires a PSD preconstruction review for greater than *de minimis* net increases in the potential to emit of a major stationary source for any pollutant subject to regulation under the Act.

Twenty-three commenters supported exempting nonattainment pollutants from PSD review. However, three commenters argued that PSD review should apply to nonattainment pollutants emitted in minor amounts, claiming that review in nonattainment areas should be as broad as that in PSD areas. EPA agrees with the former comments. As noted earlier, sections 165(a) and 169(1) apply to "any" pollutant regulated under the Act. The only restraint on PSD review, then, is section 173 in Part D, which governs the specific review of sources emitting nonattainment pollutant(s) in major amounts. In addition, sources emitting the nonattainment pollutants in minor amounts are subject to the general NSR contained in SIPs, and the impacts of such sources are accounted for in demonstrations of reasonable further progress and within the growth allowance provisions of the SIP. Thus, there is no need to apply PSD review to either type of nonattainment pollutant which already faces adequate review.

Twenty-three commenters also supported exempting from PSD review sources which emit only nonattainment pollutants in major amounts, but PSD pollutants in minor amounts, citing *Alabama Power* for support. Neither *Alabama Power* nor the Act support such an exemption. *Alabama Power* held that, at a minimum, PSD review does not apply to major sources which locate in an area designated nonattainment for all criteria pollutants. But the court did not take into account the fact that the same source may emit both PSD and nonattainment pollutants. Since, as noted above, section 165(a) does not link the pollutant for which the source is major and the pollutant for which an area is designated attainment or unclassifiable, EPA interprets section 165(a) as requiring PSD review for each source that is major for some pollutant and locates in an area designated attainment or unclassifiable for that or any other pollutant and that this review encompasses PSD pollutants whether or not emitted in major amounts.

Finally, some commenters perceived an inconsistency in requiring broader pollutant applicability for PSD review than for nonattainment review, yet using a broader definition of "source" for nonattainment areas than for PSD areas. However, EPA's actions are consistent with the Act. The scope of PSD review applicability and the nonattainment definition of source are separate issues and there is no basis for requiring that they be resolved in such a way as to in some manner equalize their effects.

XIII. Baseline Concentration, Baseline Area, and Baseline Date

EPA's June 1978 PSD regulations generally define baseline concentration as the ambient concentration level reflecting actual air quality as of August 7, 1977, including projected emissions of major sources commencing construction or modification before January 6, 1975, but not in operation by August 7, 1977, and excluding emissions from major sources commencing construction (including modification) after January 6, 1975. (40 CFR 51.24(b)(11), 52.21(b)(11) (1979).) Emissions from major source construction commencing after January 6, 1975, as well as most emissions increases occurring from existing sources after the baseline date are counted against the applicable PSD increments. (A more detailed discussion of the relationship between baseline concentration and increment consumption is provided in Increment Consumption.) Actual air quality includes emissions increases after the baseline date at existing sources whose emissions are counted in the baseline concentration, if the increases are due to increased hours of operation or capacity utilization authorized under the SIP and reasonably anticipated to occur on the baseline date. The baseline concentration also includes emissions increases allowed under a SIP relaxation pending final EPA approval on the baseline date, if the allowable emissions under the revision were higher than the source's actual emissions on the baseline date. The June 1978 regulations established a uniform baseline date of August 7, 1977 for all clean air areas. A definition of baseline area was unnecessary since all PSD areas were covered by the August 7, 1977 baseline date.

The *Alabama Power* decision held that a uniform baseline date was not authorized by section 169(4). It required the baseline date to be established at the time of the first application for a permit in an area subject to PSD requirements. EPA's regulations were consequently remanded for change.

The *Alabama Power* decision, however, supports EPA's definition of baseline concentration. In holding that monitoring data is required under section 165(e)(2), the court confirmed that actual air quality data should be used to determine baseline concentrations. *See* 13 ERC 2022. Since monitoring data provide information on actual air quality concentrations from

existing sources and since section 169(4) explicitly states that required monitoring data should be used in establishing baseline concentrations, the court's decision supports EPA's requirement that baseline concentrations reflect actual air quality. In addition, the court implicitly affirmed EPA's approach in ruling that EPA correctly excluded from baseline concentrations emissions increases due to voluntary fuel switches after the baseline date. Since actual air quality on the baseline date would not reflect these increases, their exclusion from baseline concentrations is consistent with EPA's actual air quality approach to baseline concentrations. Finally, the court noted Congress' rejection of a House bill that would have allowed certain source emissions to be included in baseline concentrations, even though the emissions have not occurred by the baseline date. *See* 13 ERC 2026. The court concluded that Congress considered and rejected an approach that would depart from actual air quality in calculating baseline concentrations, except in the limited circumstances set forth in section 169(4).

In its September 5, 1979 response to the court's decision, EPA proposed to delete the uniform August 7, 1977 baseline date and to define baseline date as the date of the first complete application, after August 7, 1977, for a PSD permit to construct or modify a major stationary source in an area subject to PSD requirements. As part of that definition, EPA proposed to define baseline area as all parts of an Air Quality Control Region (AQCR) designated as attainment or unclassifiable under section 107(d) of the Act. Under that definition, an application of a major stationary source to construct in any part of an AQCR designated as attainment or unclassifiable would trigger the baseline date for both SO_2 and PM in all portions of the AQCR.

EPA's proposed definition of baseline area was based in part on its consistency with the term "area" as used in section 107, which requires air quality designations for AQCRs or portions thereof. The definition was also intended to avoid implementation problems that might result from having different baseline areas and dates within the same AQCR. EPA proposed, however, to allow states some flexibility in defining baseline area. *See* discussion at 44 FR 51942.

EPA further proposed to retain its current definition of baseline concentration but asked for comment on a particular problem specific to the Gulf Coast areas (*see* 44 FR 57107, October 4, 1979 and discussion in Increment Consumption). EPA's September 5 proposal specifically asked for comment on two aspects of its proposal: (1) whether baseline area should be defined as clean portions of the AQCR in which a source applies for a permit, and (2) whether a permit application should trigger the baseline date only in the clean portions of the AQCR in which the source would locate or also in clean areas of any AQCR which would be impacted by the source.

After issuance of the court's full opinion in December, EPA proposed and asked for comment on three changes to its September 5 proposal (45 FR 6802, January 30, 1980). First, EPA stated it was considering defining baseline area as any area designated attainment or unclassifiable under section 107(d) in which a source subject to PSD requirements would locate or impact, rather than all clean portions of an AQCR in which a source would locate or impact. Second, EPA's solicited comment on whether states should be allowed to redefine the boundaries of areas designated as attainment or unclassifiable. EPA suggested, however, that states should be limited to redesignations no smaller than the source's area of impact. Third, EPA indicated it was considering adoption of a pollutant-specific baseline date and area. Under that approach, a source would trigger the baseline only for the pollutants it emitted. Thus, if the source would emit neither SO_2 nor PM, it would not trigger any baseline. EPA also requested comment on whether a source which would be major for SO_2 and minor for PM would trigger a baseline date only for SO_2 or for both pollutants.

EPA's final action and response to comments on each of the issues is discussed below. For simplification, the discussion focuses on the four basic issues of baseline concentration, baseline area, baseline date, and pollutant-specific baseline. Issues related to increment consumption are discussed in the next section.

A. Baseline Concentration

As proposed, EPA is continuing its current definition of baseline concentration as the ambient concentration levels at the time of the first permit application in an area subject to PSD requirements. Baseline concentration generally includes actual source emissions from existing sources but excludes emissions from major sources commencing construction after January 6, 1975. Actual source emissions are generally estimated from source records and any other information reflecting actual source operation over the two-year time period preceding the baseline date. The baseline concentration also includes projected emissions from major sources commencing construction (including modification) before January 6, 1975, but not in operation by August 7, 1977.

Unlike the June 1978 policy, baseline concentration will no longer routinely include those emissions increases after the baseline date from sources contributing to the baseline concentration, which are due to increased hours of operation or capacity utilization. Existing policy permitted this grandfathering, provided such increases were allowed under the SIP and reasonably anticipated to occur as of the baseline date. Today's policy which normally excludes such increases is consistent with using actual source emissions to calculate baseline concentrations. An actual emissions policy, however, does allow air quality impacts due to production rate increases to sometimes be considered as part of the baseline concentration. If a source can demonstrate that its operation after the baseline date is more representative of normal source operation than its operation preceding the baseline date, the definition of actual emissions allows the reviewing authority to use the more representative period to calculate the source's actual emissions contribution to the baseline concentration. EPA thus believes that sufficient flexibility exists within the definition of actual emissions to allow any reasonably anticipated increases or decreases genuinely reflecting normal source operation to be included in the baseline concentration.

EPA is also promulgating a change in its current policy on SIP relaxations. Under that policy, emissions allowed under SIP relaxations pending on August 7, 1977 are included in the baseline concentration if the allowed source emissions were higher than actual source emissions. EPA adopted that policy in June 1978 in recognition of the fact that some states with SIP revisions pending on August 7, 1977 had allowed sources to increase emissions prior to final EPA approval of the relaxations, while other states with pending relaxations had required sources to comply with the lower emissions limitations in the existing SIP until final approval occurred. *See* 43 FR 26401 col. 3. To avoid penalizing sources in states that did not allow increases prior to approval, EPA provided that baseline concentrations include the allowable emissions under revised SIPs, if the relaxation was pending on August 7, 1977 and the allowed emissions exceeded the source's actual emissions.

The effect was to allow sources to avoid increment consumption analyses for the emissions increase allowed in the revision. EPA considered the exemption justified because states and sources were unaware that EPA would establish a uniform baseline date of August 7, 1977, and those emissions increases after that date would consume increment.

EPA believes this exemption from increment consumption analyses is no longer necessary. States and sources have been on notice since June 1978 that emissions increases at existing sources due to SIP relaxations must be evaluated for possible increment consumption. No state or source has been uncertain as to the applicable baseline date, or been placed in an inequitable position as to other states or sources. Therefore, today's regulations do not exempt from increment consumption analyses those SIP relaxations not finally approved by EPA prior to the baseline date in the affected area.

One commenter suggested that EPA extend the transition provision within the June 1978 regulations for assessing increment consumption. 43 FR 26401 col. 2. This provided that increased emissions from plan relaxations received after the August 7, 1977 baseline date but before the June 19, 1978 promulgation would consume the applicable increment but could be reviewed as part of the periodic assessment rather than assessed individually for increment consumption prior to plan approval.

EPA does not believe that a similar exception is required under today's regulations. EPA considered the exception necessary in June 1978 due to uncertainty as to how the 1977 Amendments would affect pending SIP relaxations. Such uncertainty no longer exists, since sources have been on notice since June 1978 that SIP relaxations after that date must be individually reviewed for increment consumption. Therefore, emissions increases due to plan relaxations received after June 19, 1978 must be individually evaluated for increment consumption prior to EPA approval.

EPA is concerned, however, that the new definition of baseline concentration may work a hardship on states with SIP relaxations pending when a PSD application is filed in an area. A state may submit a SIP relaxation affecting a source, or group of sources, located in an area where the baseline date has not been set, and would not be required to provide an increment consumption analysis. If prior to final EPA approval, a source filed a PSD application in the area, the application would establish a baseline date and the state would have to withdraw the revision until it has conducted the necessary increment analysis. To prevent such burdensome delays, EPA is exempting from individual increment analyses SIP relaxations pending at the time a baseline date is established in the area affected by the revision. However, increment consumption due to emissions from these relaxations must be evaluated as part of a state's periodic assessment. Exemptions from individual analyses is analogous to the previous relief provided for sources subject to SIP relaxations submitted after August 7, 1977, but before EPA's June 1978 promulgation. The exemption is therefore consistent with prior EPA policy.

B. Baseline Area.

In response to the September 5, 1979 proposal, fifty-three commenters felt that an AQCR definition of baseline area would not produce a great deal of administrative relief and would, simultaneously, limit an area's growth options. These commenters favored defining baseline area as the area of significant source impact, based on required modeling and monitoring analysis. Such an approach was claimed to provide just as much administrative relief, more growth options, and elimination of the problem of a small PSD source triggering the baseline date for a large area. Seventeen commenters favored a baseline area definition geared to areas designated as clean or unclassified under section 107. Those favoring this alternative strongly preferred a "redesignation" procedure to accompany this option. Other commenters objecting to the AQCR approach suggested: county boundary lines (three), and the entire state (one).

In response to EPA's January 30 notice, fourteen of sixteen commenters favored a source impact area definition of baseline area. One of the remaining two commenters favored retention of the AQCR approach while the other commenter desired a county or some other legal boundary approach. All eighteen comments received favored triggering a baseline only in the area in which a source would locate, and not in those other areas which it would impact. Nineteen of twenty-nine commenters favored permitting state redesignation but to areas no smaller than a source impact area. Seven other commenters favored no limitations on the redesignation procedure. The remaining three commenters opposed allowing states to redefine baseline areas through redesignation.

EPA has determined that baseline area should be defined as the area designated as attainment or unclassifiable under section 107(d) in which a source or modification subject to PSD review would construct or on which it would have an impact equal to or greater than 1 $\mu g/m^3$ on an annual basis. EPA has concluded that "an area subject to this part," as used in section 169(4), refers to areas designated attainment or unclassifiable under section 107(d).

This view is strongly suggested by Judge Robinson's opinion on baseline concentration in the December 1979 *Alabama Power* ruling. Referring to Congress' intent to use actual air quality data to establish baseline concentrations, Judge Robinson states that "the task of monitoring existing ambient pollution levels *in attainment areas* is assigned to the first permit applicant, who will provide the information essential to calculation of the baseline." (Emphasis added) 13 ERC 1993, 2022. The footnote which follows that sentence discusses a state's obligation under section 107(d)(1) to submit area designations to EPA and the fact that section 107 lists submitted to date by the states indicate that many areas lack acceptable air quality information. *Id.* The references to attainment areas and section 107(d) designated areas indicate that the court interprets the statute as requiring that baseline concentrations be calculated for each clean area designated under section 107(d)(1).

EPA thus believes that neither the statute nor the court opinion support the proposed AQCR approach. The majority of comments also opposed defining baseline area as AQCR. Opposition was based on the view that it would do little to alleviate administrative problems, offered no flexibility in states, and would often limit an area's growth options by encompassing too large an area.

EPA has also determined that a PSD source should trigger the baseline in all intrastate clean areas that it impacts as well as the area it locates in. One objective of PSD is to track air quality changes in clean air areas. If a major source significantly affects any clean air area in the same state the purposes of PSD will be served if air quality deterioration from minor/area source growth and actual changes in baseline source emissions are tracked from the time significant SO_2 or PM emissions from a new or modified major source impact a clean area. Such a policy is also consistent with the language of section 165(e)(1) of the Act which

requires an air quality analysis of the affected area, not just the area of immediate location. The Administrator does not believe that such a policy should transcend state boundaries. Since triggering baseline dates is an important factor in managing growth, EPA has concluded that states should have jurisdiction over their own baseline dates. On the other hand, establishment of baseline dates does not affect increment consumption across state borders by major source construction commencing after January 6, 1975.

EPA has concluded that baseline areas may be redefined by the states through area redesignations. Section 107(d) specifically authorizes states to submit redesignations to the Administrator. Consequently, states may submit redefinitions of the boundaries of attainment or unclassifiable areas at any time. If EPA agrees that the available data support the change, it will redefine the areas as requested. As long as no PSD source has located in, or significantly impacted on a clean area being considered for redesignation, the area can be redesignated as a new attainment or unclassifiable area, even if the area were previously part of a larger clean area in which the baseline date had been set.

Area redesignations are subject to certain restrictions. The boundaries of any area redesignated by a state cannot intersect the area of impact of any major stationary source or major modification that established or would have established a baseline date for the area proposed for redesignation or that is otherwise required to obtain a PSD permit. In addition, area redesignations can be no smaller than the area of impact of such sources. These restrictions comport with the PSD objective of tracking air quality effects in an area once a major source or modification has affected an area. By setting the baseline date at the time a major source or modification impacts an area and preventing the date from being changed by subsequent area redesignations, the system ensures that future growth in the area will be assessed for its air quality effects from that date forward. Moreover, if states could define baseline areas as small as the immediate area in which a source is located and not include the source impact area, air quality could deteriorate or increments could be violated in a nearby area impacted by the source, but neither the state nor EPA would review the air quality impact. The source could therefore affect air quality but the reviewing authority would be unaware of the deterioration. In addition to jeopardizing air quality, "postage stamp" baseline areas would be difficult to administer.

A source will be considered to impact an area if it has an impact of 1 $\mu g/m^3$ or more of SO_2 or PM on an annual basis. This figure has been selected because it corresponds to levels of significance used in previous Agency determinations for SO_2 and PM. The annual average was selected over the short term value due to its ease of implementation. That is, the shape of source impact areas is less complex and the 1 $\mu g/m^3$ annual average provides ample area coverage of the source impact area.

The Administrator believes that defining baseline area as section 107 areas and allowing state redesignation will satisfy most of the commenters who objected to the proposed AQCR definition and favored state flexibility in designations. The redesignation process partially meets the concerns of commenters who preferred defining baseline area as source impact area. Where a baseline date is established for an area that is large relative to the impact area of the triggering source, the state has the option of redefining the area to reflect more accurately the area affected by the source.

C. Baseline Date

Consistent with the Agency's proposal, today's promulgation defines baseline date as the date after August 7, 1977 on which the first complete application for a PSD permit is filed with the appropriate reviewing authority. Section 51.24(b)(14), 52.21(b)(14). As discussed in the September 5 notice, EPA has determined that this definition is mandated by the court's interpretation of section 169(4), which requires a baseline concentration to be set on the date, after August 7, 1977, "of the first application for a permit in an area subject to this part." *See* 44 FR 51941 col. 3. Consequently, the first complete PSD permit application by a major source to construct in a baseline area, as that term is defined in § 51.24(b)(15) and 52.21(b)(15), and explained above, will trigger a baseline date.

As discussed below, under *Pollutant-Specific Baseline*, the regulation further requires that a baseline date be set for each pollutant emitted by the applicant source in greater than *de minimis* amounts, if increments or other equivalent measures under section 166 have been established for the pollutant. At present, increments are established only for SO_2 and PM, and no increments or equivalent measures for other pollutants have been established. Section 166 requires EPA to adopt regulations establishing increments or other equivalent measures for other criteria pollutants. Section 166 does not by its terms require EPA to apply section 169(4) in determining baseline dates for criteria pollutants other than SO_2 and PM. EPA is now conducting rulemaking under section 166 to develop increments or equivalent measures for the other criteria pollutants. As part of that rulemaking, EPA is considering how to establish baseline dates for those pollutants.

While comments supported EPA's proposal to establish the time of the first complete application in an area as the baseline date, eight commenters suggested that the date be set at the time of the first application after August 7, 1978, rather than August 7, 1977. This review is consistent with other comments noting that section 165(e)(2) requires permit applicants after August 7, 1978 to provide one year's monitoring or other equivalent air quality analysis to determine a baseline concentration for the area. These commenters claimed that since baseline concentration is to be established through actual ambient air quality data and no applicant can gather the necessary monitoring data before one year after the effective date of the part, the baseline date should not be triggered by applications filed before that date.

EPA understands the commenter's concerns. However, EPA believes Congress was aware that prior to August 7, 1978, applicants could not provide a full year of monitoring data, as evidenced by the fact that the monitoring requirement in section 165(e)(2) is not effective until August 7, 1978. Congress nonetheless provided that baseline concentrations be established by the first permit application, an event which could occur at any time after August 7, 1977. Congress therefore considered that baseline concentrations and increment consumption could be determined with less than a full year's monitoring data. The need to accept less data is reflected in the provision of section 169(4) that baseline concentrations be based on available air quality data and on such monitoring data as the applicant is required to submit. The provision suggests that calculations of baseline and increment use may have to be made with limited data, if available data, such as that from the state agencies, is not appropriate. EPA interprets the requirements for monitoring data after August 7, 1978, and not August 7, 1977, as intended to provide a grace period for sources, rather than evidencing intent to

postpone the establishment of baseline dates.

One commenter questioned whether baseline dates would be triggered by permit applications previously filed by sources that were major under the June 1978 PSD regulations, but no longer major under the regulations promulgated today, even if the permit applicant failed to apply for a permit rescission. EPA concurs in the commenter's suggestion that a subsequent permit applicant in any area may inform the permitting authority that the baseline date was not triggered on the date that a source which no longer qualifies as major applied for a PSD permit. As the commenter points out, this eliminates the need for an immediate rescission of all past permits affecting sources no longer subject to PSD review. It also avoids penalizing permit applicants if a source that is no longer major fails to apply for a permit rescission.

The Administration wishes to clarify another point related to a change in review status for the source which has triggered the baseline date. If the applicant that established the baseline date is later denied a PSD permit or voluntarily withdraws its PSD application, a question arises as to whether the baseline date has been triggered. In the Administrator's judgment the applicable baseline date remains in place, since no change in date is authorized under the Act. Section 169(4) establishes source application as the baseline triggering mechanism and does not qualify this by the later issuance of a permit. This policy is consistent with the establishment of a baseline concentration which is based on the available monitoring data, typically that gathered by the source applicant. The data to establish the baseline concentration would be available regardless of the eventual permit status of the baseline triggering application. Using source application also stabilizes the NSR permitting process. Later applicants can determine whether a baseline date has been set in an area by looking to whether a previous application has been filed, rather than needing to determine if the permit has been or will be issued.

Finally, the Administrator wishes to point out that it is the first PSD application submitted under either 40 CFR 52.21 or state PSD regulations developed pursuant to 40 CFR 51.24 which triggers a baseline date. When states assume responsibility for implementing the PSD program, several PSD baseline dates may well have been triggered. However, as mentioned above, states can minimize the impact of early baseline dates by redesignating the size of the baseline area which is affected by a previously established baseline date.

D. Pollutant-Specific Baseline

The Agency has concluded that a pollutant-specific baseline is consistent with section 169(4) and the statutory structure. Section 169(4) requires that a baseline concentration be established "with respect to a pollutant * * * in an area subject to (Part C)." Therefore, by the terms of the statute, a baseline concentration is established for individual pollutants. Moreover, such concentrations are established for areas subject to PSD. Section 107(d), which provides that areas designated attainment or unclassifiable are subject to PSD, requires designations to be made on a pollutant-specific basis. Section 107(d)(1)(D) and (E). To be consistent, both baseline date and baseline area (and any subsequent redesignations under section 107 of the Act) must also be pollutant-specific.

The comments that favored a pollutant-specific baseline generally did so on two grounds: the reference to "pollutant" in section 169(4) and the statutory requirement to use monitoring data to establish baseline concentration. Since monitoring and increment consumption are pollutant-specific, baseline concentrations must be as well. The Administrator agrees that the monitoring requirement supports pollutant-specific baselines. Four of the thirty-eight commenters that opposed pollutant-specific baselines did so primarily for implementation reasons. Although pollutant-specific baselines may add some complexity to the PSD program, EPA has concluded that the statutory structure contemplates pollutant-specific area designations.

The following example illustrates the concept of pollutant-specific baseline dates. If a major source of NO_x that would also emit SO_2 in significant amounts and PM in less than significant amounts submits a complete application for a permit to construct in an area designated under section 107(d)(1) as attainment for all pollutants, and no previous source has triggered any baseline dates, the source would establish the baseline date for SO_2 but not PM. If a later modification to the source results in a significant net increase in PM emissions and no other application previously triggered the PM baseline date, the proposed PSD application for the modification would then establish the PM baseline date.

XIV. Increment Consumption

There are two basic issues in the area of increment consumption: (1) which source emissions consume increment and (2) how to calculate the amount of increment consumed by those emissions. The *Alabama Power* decision addressed neither question. EPA, therefore, proposed in September to continue its current approach. Under the approach, four categories of source emissions affect increment: (1) as provided by section 169(4), emissions from major source construction (including modification) commencing after January 6, 1975. This group includes emissions from sources issued PSD permits and state new source review (NSR) permits (including those issued in accordance with section 51.18(j) and the Offset Ruling) as well as emissions from non-permitted sources; (2) emissions changes occurring after the baseline date at sources whose previous emissions on the baseline date are included in the baseline concentration; (3) emissions changes due to SIP revisions that are approved after the baseline date; and (4) minor and area source growth occurring after the baseline date. EPA's current regulations provide that the first and third category of sources affect increment on the basis of emissions allowed under the permit and emissions allowed under the SIP as revised, respectively. The second and fourth categories affect increment on the basis of actual emissions changes from the emissions included in the baseline concentration.

Since its proposal, EPA has reevaluated its current policy in light of both the December opinion of the court and the Gulf Coast problem (discussed below). EPA has concluded that increment consumption and expansion should be based primarily on actual emissions increases and decreases, which can be presumed to be allowable emissions for sources subject to source-specific emissions limitations. This change principally affects increment calculations for major source construction not subject to source-specific permits or SIP requirements and for sources whose allowable limits are demonstrated not to reflect actual emissions. PSD applications pending today before EPA or a state agency authorized to review or issue PSD permits will be reviewed for increment consumption on the basis of the revised policy.

A. Use of Actual Emissions

1. Rationale for Use of Actual Emissions.

As discussed in the *Baseline Concentration* section, the *Alabama Power* decision supported EPA's requirements that baseline concentrations reflect actual air quality in an area. Increment consumption or expansion is directly related to baseline concentration. Any emissions not included in the baseline are counted against the increment. The complementary relationship between the concepts supports using the same approach for calculating emissions contributions to each. Since the *Alabama Power* decision and the statute both provide that actual air quality be used to determine baseline concentrations, but provide no guidance on increment consumption calculations, EPA has concluded that the most reasonable approach, consistent with the statute, is to use actual source emissions, to the extent possible, to calculate increment consumption or expansion.

EPA's decision is also based on concerns raised by the Gulf Coast problem, discussed below. In that area, and possibly others, source emissions allowed under permits and SIP provisions in many cases are higher than actual source emissions. Sources could therefore increase their emissions without being subject to PSD review or the SIP revision process. However, if increment calculations were based on allowable emissions, EPA believes increment violations would be inappropriately predicted and proposed source construction would be delayed or halted. In practice, EPA expects that few, if any, sources will increase their emissions to allowable levels.

EPA believes it is unwise to restrict source growth based only on emissions a source is permitted to emit but which, in many instances, have not been and are not likely to ever be emitted. Increment calculations based on the best prediction of actual emissions links PSD permitting more closely to actual air quality deterioration than calculations based on allowable "paper" emissions. In addition, use of actual emissions for increment consumption is consistent with using an actual emissions baseline for defining a major modification and for calculating emissions offset baselines.

2. Calculation of Increment Consumption Using Actual Emissions.

To determine how much increment remains available to a proposed major source or modification, the source owner or operator must analyze several types of emissions changes as of its application date. These changes generally include: (1) emissions changes that have occurred at baseline sources and emissions from new minor and area sources since the baseline date; (2) emissions that have occurred or will occur at sources which have submitted complete PSD applications as of thirty days prior to the date that the proposed source files its application; and (3) emissions changes reflected in SIP relaxations submitted after August 7, 1977, and pending as of thirty days prior to the date the source files its application, or emissions changes reflected in SIP relaxations which have been approved since August 7, 1977, but which have not yet occurred. (*See*, discussion below on calculation of increment consumption for SIP relaxations.) The thirty-day cutoffs are specified to stabilize the review process by preventing new applications and SIP relaxation proposals from invalidating otherwise adequate increment consumption analyses without warning.

Increment calculations will generally be based on actual emissions as reflected by normal source operation for a period of two years. EPA has selected two years based on its recent experience in reviewing state NSR programs for nonattainment areas. The state submittals use periods of between one and three years to evaluate source emissions. In EPA's judgment, two years represents a reasonable period for assessing actual source operation. Since the framework for nonattainment NSR programs will generally form the basis for a state's PSD plan, EPA believes it is appropriate to use the same time period for evaluating actual source emissions in the PSD program. Two years is also being used to calculate the emissions offset baseline for modifications in nonattainment areas.

The two-year period of concern should generally be the two years preceding the date as of which increment consumption is being calculated, provided that the two-year period is representative of normal source operation. The reviewing authority has discretion to use another two-year period, if the authority determines that some other period of time is more typical of normal source operation than the two years immediately preceding the date of concern. In general, actual emissions estimates will be derived from source records. Actual emissions may also be determined by source tests or other methods approved by the reviewing authority. Best engineering judgments may be used in the absence of acceptable test data.

EPA believes that, in calculating actual emissions, emissions allowed under federally enforceable source-specific requirements should be presumed to represent actual emission levels. Source-specific requirements include permits that specify operating conditions for an individual source, such as PSD permits, state NSR permits issued in accordance with § 51.18(j) and other § 51.18 programs, including Appendix S (the Offset Ruling), and SIP emissions limitations established for individual sources. The presumption that federally enforceable source-specific requirements correctly reflect actual operating conditions should be rejected by EPA or a state, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or the permit.

EPA believes two factors support the presumption that source-specific requirements represent actual source emissions. First, since the requirements are tailored to the design and operation of the source which are agreed on by the source and the reviewing authority, EPA believes it is generally appropriate to presume the source will operate and emit at the allowed levels. Second, the presumption maintains the integrity of the PSD and NSR systems and the SIP process. When EPA or a state devotes the resources necessary to develop source-specific emissions limitations, EPA believes it is reasonable to presume those limitations closely reflect actual source operation. EPA, states, and sources should then be able to rely on those emissions limitations when modeling increment consumption. In addition, the reviewing authority must at least initially rely on the allowed levels contained in source-specific permits for new or modified units, since these units are not yet operational at a normal level of operation. EPA, a state, or source remains free to rebut the presumption by demonstrating that the source-specific requirement is not representative of actual emissions. If this occurs, however, EPA would encourage states to revise the permits or the SIP to reflect actual source emissions. Such revisions will reduce uncertainty and complexity in the increment tracking system, since it will allow reviewing authorities and sources to rely on permits and SIP emissions limitations to model increment consumption.

Review of increment usage due to SIP relaxations will also be based initially on emissions allowed under the SIP as revised (provided this allowed level is higher than the source emissions contributing to the baseline concentration). Calculations will generally be made on the difference between the source emissions included in the baseline concentration and the

emissions allowed under the revised SIP. Initial use of allowable emissions is necessary because the increment calculation generally occurs before the source has actually increased its emissions. Therefore, at the time the revision is reviewed, increment consumption must be based on the predicted source operation under the revision. In addition, since SIP revisions are commonly based on source requests, it is reasonable to assume such sources will actually emit at levels permitted by the relaxation.

Subsequent to the initial review process, increment calculations for SIP relaxations may depart from allowable emissions under the SIP, if the source has not actually increased its emissions. For example, three years after approval of a SIP relaxation, if it is found that the source has not increased its emissions to levels allowed in the SIP, estimates of increment usage should be revised to reflect actual source emissions. If this occurs, EPA would also encourage states to revise the emissions levels allowed in the SIP to represent the source's actual emissions.

Finally, the required increment consumption analysis can be amended by the applicant after the PSD review process has begun. For example, an applicant would normally revise its analysis to reflect increment made available by the withdrawal of PSD applications previously considered in the applicant's calculation of increment consumption. In no event, however, will the source be required to take account of emissions changes or changes due to pending PSD applications or SIP relaxations that could increase the amount of increment consumed by other sources.

B. Exclusions From Increment Consumption

1. *Exclusions Requested by Governors.*

Section 163(c) authorizes four exclusions from increment consumption upon the request of a governor. Exemptions are available for federally-ordered fuel switches under the Energy Supply and Environmental Coordination Act of 1974 or superseding legislation, fuel switches due to natural gas curtailment plans under the Federal Power Act, temporary emissions of particulate matter due to construction and related activities, and new sources constructing outside the United States. In the cases of the federally-ordered switches and natural gas curtailment plans, the exclusion is limited to a maximum of five years after the effective date of the order or plan.

The statute provides that these exclusions are available only if the state has an EPA-approved PSD plan. Section 163(c). In its June 1978 regulations, however, EPA permitted governors to use the exclusions during the nine-month period between promulgation of the regulations and the date plan revisions were required to be submitted. *See* § 52.21(f)(3) (1979). As discussed in the preamble to the June 1978 regulations, EPA concluded that prohibiting use of the exclusions after the nine-month period would be an adequate incentive to states to submit PSD plans. *See* 43 FR 26402 (Col. 1).

EPA has decided to extend this policy to today's regulations. In view of the many changes in the regulations resulting from the court's decision, states which have already submitted plans will have to submit revised provisions and states which have not yet submitted plans will have to develop plans based on the new regulations. As with the June 1978 requirements, EPA believes that disallowing the exclusions nine months from today will provide sufficient encouragement to states to submit plans, and will offer states more flexibility for growth in this interim period. Therefore, governors may request the exclusions until nine months from today's promulgation, even if no PSD plan has been submitted to or approved by EPA. Thereafter, the exclusions will be unavailable unless the state has submitted an approvable PSD plan to EPA.

2. Temporary Emissions

EPA's June 1978 regulations and the September 1979 proposal provided that temporary emissions from new sources or modifications would be exempt from impact analysis requirements §§ 51.24(k)(iii), 52.21(k)(iii) (1979); 51.24(k)(1), 52.21(k)(1) (proposed). Temporary emissions typically include, but are not limited to, emissions from a pilot plant, a portable facility, construction or exploration activities. Similarly, EPA proposed to exempt from increment analyses the impacts on the PSD increments from the temporary emissions associated with the development of an approved innovative control technology system, provided the applicable ambient standards were not jeopardized. The regulations, however, did not provide a comparable exemption for temporary emissions resulting from short-term SIP relaxations.

Only three commenters addressed the concern of temporary emissions and increment consumption. These commenters offered suggestions in light of the proposed position on innovative control systems. These commenters supported the existing policy of exempting temporary emissions from increment air quality analyses when no Class I areas or areas with known increment violations would be impacted.

Temporary SIP relaxations are comparable to temporary emissions from new and modified major stationary sources since both affect air quality for a limited period of time. Therefore, the Administrator has decided that the existing policy of exempting temporary emissions should be extended to those associated with certain SIP relaxations. A SIP relaxation will be eligible for such relief if it meets the following five conditions. These conditions are intended to ensure that the emissions increase associated with the SIP relaxation will be limited in duration and that no residual harm will occur to the environment as a result of the relaxation. (1) The SIP revision allows an emissions increase for a temporary period only. As stated in the preamble to the June 1978 regulations, temporary emissions generally would last no more than two years at one location, although emissions for a longer period of time may be considered temporary if an appropriate demonstration is made. *See* 43 FR 26394 col. 2. (2) The revision is nonrenewable. This condition is intended to prevent sources from indefinitely postponing compliance with emissions limitations necessary to prevent PSD increment violations. (3) The temporary emissions will not cause or contribute to the violation of any applicable NAAQS. (4) At the expiration of the temporary SIP relaxation, the source must be required to comply with an emissions limitation that ensures the post-exemption emissions will be equal to or less than the emissions existing before the exemption was granted. (5) The temporary emissions from the revision do not impact any Class I area and any area where an increment is known to be violated. Restricting the exemption to sources impacting Class II or III areas conforms to Congress' intent to provide maximum protection of air quality values in Class I areas and meets the commenter's concerns.

In addition to SIP relaxations for individual sources, the exemption will be available for temporary emissions due to SIP relaxations that apply to several sources, if the state provides adequate assurances that no standards will be violated.

C. Increment Expansion Due to Emissions Reductions Prior to the Baseline Date

EPA's policy under the June 1978 regulations is unclear as to whether emissions reductions prior to the

baseline date increase the amount of available increments. The policy allows decreases after January 6, 1975, and prior to the baseline date, to be used by sources to offset subsequent increases and exempt the increases from the requirement for an ambient air quality assessment. In effect, EPA treats such decrease as expanding available increments, since the decreases permit later emissions increases at the same source to avoid the otherwise required air quality assessment. The policy did not state, however, whether isolated decreases not made in conjunction with intrasource increases were considered to expand available increments. In contrast, the policy is clear that emissions reductions after the baseline date increase available increments.

As a result of the revised definition of modification which permits offset credit for emissions reductions occurring within a moving five-year period, EPA has decided to clarify its existing policy. All emissions reductions prior to the baseline date at major stationary sources will now be considered to expand available increments. Since contemporaneous emissions reductions accomplished before the baseline date can be used by a source to offset a contemporaneous post-baseline emissions increase, and thereby avoid PSD review, it is also reasonable to allow these contemporaneous pre-baseline date reductions to expand the increment. Without this change, source owners that reduce emissions by retiring or controlling old equipment before the baseline date will be penalized by having increases after the baseline date count against increments even though the pre-baseline decrease might offset the later increase and eliminate the need for PSD review. In contrast, source owners that postpone the reductions and increases until after the baseline date is set would both secure contemporaneous offsets and avoid increment consumption.

EPA believes that this inequity should be eliminated to encourage early retirement of old equipment. Section 169(4) provides that emissions from major emitting facilities that commenced construction after January 6, 1975, shall be counted against available increments. The provision implies that both emissions increases and decreases should be considered for their impact on available increments. In view of the statutory language and policy considerations, EPA has determined that decreases made prior to a baseline date can expand available increments in the same manner as decreases made after a baseline date. However, to ensure that the emissions reductions remain effective, reductions will add to available increments only if the lower emissions limitations are federally enforceable.

The changed policy is reflected in a new definition of "construction" which is any physical change or change in the method of operation of a stationary source resulting in a change in the actual emissions of the source (including fabrication, erection, installation, demolition, or modification). Any construction commencing at a major source since January 6, 1975, may result in an increase or decrease in actual source emissions. If an actual decrease involving construction at a major stationary source occurs before the baseline date, the reduction will expand the available increment if it is included in a federally enforceable permit or SIP provision. An actual increase associated with construction activities at a major stationary source will consume increment.

The Administrator would also like to clarify that changes in fugitive emissions levels (to the extent quantifiable) at major stationary sources, resulting from construction commenced since January 6, 1975, will consume or expand the available increment. This is true even if such changes occurred prior to the baseline date.

D. Gulf Coast Problem.

In the September 5 proposal, and in an October 4, 1979 correction notice, EPA solicited comments on how to calculate increment consumption by gas-fired boilers in the Gulf Coast area that had received state approval to burn oil in the event of a future natural gas shortage. *See* 44 FR 51942 (September 5, 1979), and 44 FR 57107 (October 4, 1979). The affected units include both boilers that could accommodate such a fuel-switch before January 6, 1975 and boilers that were altered to accommodate the fuel-switch after that date. All affected units were permitted to switch fuel before August 7, 1977, the earliest possible baseline date. Assuming the baseline date is set in the area where these sources are located, which EPA believes is the case for most of the sources, each group of sources may cause increment violations.

For sources that could burn alternative fuels prior to January 6, 1975, the problem is posed by the fact that if all sources made the switch to oil allowed under their permits, SO_2 increment violations would occur. Since neither a SIP revision nor a PSD Permit would be required for the sources to make the fuel switches, EPA and the state could be unaware of the violations until another source applied for a PSD permit or until a periodic assessment was made. If actual increment violations were discovered during the PSD review process for the proposed source, the source would not be permitted to build or modify until the violations were corrected. If violations were found during a periodic assessment, the state would have to suspend further growth until its plan was revised to correct the violations. Consquently, the inadequacy of the exiting permits to prevent increment violations could result in increment violations which would delay, and possibly prevent, additional growth in the area.

A similar problem is posed by sources that could not accommodate oil before January 6, 1975. Since these sources increased their potential to emit after January 6, 1975, under EPA's June 1978 policy, this change would have constituted "construction" at a major stationary source after January 6, 1975. Therefore, under section 169(4), any emissions increases caused by the "construction" would have consumed increment. As noted above, EPA's June 1978 policy required increment calculations to be based on emissions allowed under a permit or SIP and not on actual source emissions. If a PSD source applied to locate in an area and these Gulf Coast sources were modeled based on emissions increases due to fuel switches allowed by their permits, EPA believes several SO_2 increment violations would be predicted. Under existing policy, the proposed PSD source would then be required to correct the violations prior to receiving construction approval. Future growth in the area could, therefore, be delayed or prevented.

The problem posed by the second group of sources is reduced to some extent by the increment consumption policy promulgated today. Since increment usage will now be based on changes in actual source emissions, increment violations will not occur in the area unless the sources actually switch to oil from natural gas. Because natural gas is expected to remain less expensive and more available than oil, EPA believes few, if any, switches are likely. Therefore, while the increments may still be jeopardized due to inadequate permit conditions, PSD review can proceed as long as actual emissions increases at existing sources and actual emissions from sources with PSD or NSR permits are not predicted to cause increment violations.

If an actual increment violation has occurred, EPA's June 1978 policy imposes a PSD permit moratorium until

the violation is corrected. 43 FR 26401 (col. 1), June 19, 1978. This policy is continued in today's regulations. Therefore, if an increment violation is predicted to occur within the significant impact area of a proposed source (1 $\mu g/m^3$ on an annual average), a PSD permit cannot be issued to the source, unless the state or source obtains sufficient emissions reductions to restore the increment. The issue of how to deal with potential increment violations due to inadequate permit conditions is addressed in the next discussion.

Several comments were received in response to EPA's request for comments on the Gulf Coast problem. Although EPA believes its revised policy of using actual emissions to calculate increment consumption resolves the immediate Gulf Coast dilemma, and similar potential problems in other states, EPA is responding below to suggestions made by commenters.

EPA's notices questioned whether the Agency should or may include in the baseline concentration emissions increases due to fuel switches. Twelve of thirteen commenters on the issue supported including increases due to fuel switches in the baseline concentration and the majority of the commenters favored including in the baseline concentration other emissions increases approved prior to the baseline date but not occurring by that date. Commenters also proposed using allowable emissions in all cases to calculate baseline concentrations.

As discussed above and in Baseline Concentration, EPA has determined that both baseline concentrations and increment consumption should be based on actual air quality impacts. This decision is consistent with the suggestion of some commenters that EPA consider increment consumption to occur only when actual emissions increase and not when the permit or SIP allowing the increase is approved. As a result of EPA's revised policy, emissions increases due to fuel switches cannot be included in the baseline concentration unless the increase occurred prior to the baseline date and at a source which could accommodate this switch prior to January 6, 1975 without physical change or received approval under a PSD permit to make the switch.

One commenter was particularly concerned that unless allowable emissions were included in the baseline concentration, utilities with SIP relaxations approved shortly before the baseline date would be penalized if the utilities were unable to make the allowed increase by the baseline date. The commenter argued that some utilities would be unable to make the technical changes necessary to accommodate the fuel switch prior to the baseline date. Such utilities would, therefore, be required to do an increment consumption analysis, in contrast to other sources that made the switch before the baseline date. The commenter suggested that accounting for the allowed emissions increase in the baseline concentration would resolve this inequity and would be consistent with EPA's June 1978 policy of including in the baseline concentration emissions allowed under SIP relaxations pending before EPA on the baseline date.

While appreciating the commenter's concerns, EPA has concluded that no exemption from increment consumption analyses is appropriate in these cases. First, as discussed in Baseline Concentration, EPA has changed its June 1978 policy to provide that increment is consumed by emissions increases due to SIP relaxations pending EPA approval on the baseline date. Therefore, the exemption cited by the commenter no longer applies. Second, the June 1978 exemption was provided for sources whose emissions increases were delayed by the administrative process and not by physical limitations at the source. Therefore, the June 1978 exemption would not have applied to these utilities. Third, under the regulations promulgated today, if significant construction is necessary to make the allowed emissions increase, the change is a modification and would be subject to PSD review, including increment consumption analysis, in any case.

Other commenters suggested that prospective application of the definitions of major emitting facility and modification promulgated today would resolve the Gulf Coast problem. Under this approach, emissions increases that occurred after January 6, 1975, and would otherwise be considered modifications that consume increment under today's regulations, would not be evaluated under the new definitions. These commenters argued that the Gulf Coast problem is due to increment consumption from emissions increases not subject to the PSD permitting process at the time the increases were approved. The commenters stated that EPA has flexibility in deciding the effective date of the definitions.

EPA believes that section 169(4) requires emissions from all major emitting facilities (as defined in the Act and not as defined in the old PSD regulations) commencing construction after January 6, 1975 to count against increment. The statute provides no discretion to exempt these emissions from increment consumption. EPA also notes that under the PSD regulations effective from January 6, 1975 to August 7, 1977, emissions increases at such sources would have consumed increment to the extent the fuel switches occurred. (*See* 39 FR 42510).

E. Potential Increment Violations

1. Inadequate SIP and Permit Provisions. While the use of actual emissions to calculate increment consumption partially resolves the Gulf Coast problem, the potential for increment violations remains, due to inadequate SIP and permit provisions. As stated in the preceding discussion, many sources in the Gulf Coast area, and in other states as well, have permits or SIP requirements that allow actual emissions increases without subjecting the source to PSD review or the SIP revision process. For example, sources may be allowed to burn fuels with higher sulfur contents, as in the Gulf Coast area, or may have high allowable limits that would permit sources to relax existing pollution controls. If all sources in an area increased actual emissions to levels allowed under the SIP or permits, EPA believes increment violations would occur. Because no PSD review or SIP revision would be required, neither the state nor EPA would know of the violations until a PSD application was filed or a periodic assessment occurred. Growth would be halted until the violation was corrected.

At present, increment violations due to allowed but unreviewed emissions increases, and consequent construction delays, are only potential problems. EPA has therefore concluded that it is premature to promulgate remedial regulations to prevent such theoretical violations. EPA, however, encourages states to be alert to emissions increases that affect the increment. EPA urges states to closely monitor emissions increases from baseline sources and from new or modified sources not subject to PSD review which affect the available increment. States should consider requiring sources to report any emissions increases after the baseline date, including increases reflecting changed operating conditions that will continue for an extended period of time, perhaps six months. States would then learn of increases that consume increments and could take those increases into account in PSD permit reviews and periodic increment assessments. In addition, states are encouraged to revise SIPs and/or issue operating permits so that SIP requirements and permits reflect actual

source operating conditions. This will protect against large unreviewed emissions increases. While EPA is not promulgating a reporting requirement today, it will reconsider the need for a notification system if it finds that unreviewed emissions increases are causing or contributing to increment violations.

2. Double Counting of Emissions Decreases.

EPA is concerned about another potential problem: double counting of emissions decreases. The problem could arise if an existing source (Source A) reduces its actual emissions and a new source (Source B) seeking to locate in the area proposes to use the decrease when modeling increment consumption. Source B would do this by including the emissions decrease in its modeling of actual emissions from Source A. If the reviewing authority does not require Source B to ensure that the decrease at Source A is federally enforceable and does not record Source B's use of the decrease at the time Source B conducts its modeling, Source A may well use the same decrease to offset a future contemporaneous increase at Source A and thereby avoid PSD review for the increase. The use of one emissions decrease to offset two emissions increases could lead to air quality deterioration, and possible increment violations that would require correction before more PSD permits could be issued.

While EPA believes double counting of decreases should not be permitted, it is not promulgating regulations today to address the problem. EPA is uncertain how often, if ever, the problem will arise. Certainly it will be difficult for a new source to prove to the satisfaction of the reviewing authority the value of an emissions decrease accomplished at another source. Moreover, while EPA believes double counting of decreases should not occur, it is uncertain what solution is equitable for affected sources. In the absence of a formal increment banking system, or other provisions regulating increment allocation, the reviewing authority would have no basis for denying Source B use of any available increment. This could result in hardship to Source A if it deprives Source A of use of its decrease as an offset for future increases.

The issue of double counting is part of the broader question of increment management and allocation of air quality rights. EPA intends to develop banking regulations, which will include guidance to states on methods of increment allocation and regulating use of emissions decreases. To this end, EPA solicits suggestions on how to prevent double counting of decreases and on methods of increment allocation and management.

XV. Best Available Control Technology

Section 165 of the Act provides in part that any "major emitting facility" constructed in a PSD area must apply best available control technology (BACT) "for each pollutant subject to regulation under this Act emitted from, or which results from, such facility." Section 169(3) of the Act defines BACT and specifically requires that it not be applied in a manner so as to result in emissions in excess of those that are allowed by standards established pursuant to sections 111 or 112 of the Act. 42 U.S.C. 7479(3). The Agency's existing regulations required BACT only for each pollutant for which a source or modification would be "major." 40 CFR 51.24(i)(1), 52.21(i)(1)(1978).

The *Alabama Power* decision held that the Act requires that BACT be applied to all pollutants subject to regulation under the Act, not only those for which the source is major, and that EPA is without authority to circumscribe the requirement in this manner. 13 ERC 1993, 2046. The court did conclude, however, that EPA has authority to set *de minimis* thresholds for BACT applicability, in order to alleviate economic and administrative burdens. *Id.*

In response to the court's decision, EPA proposed and is now promulgating regulations regarding application of BACT. 40 CFR 51.24(k)(1), 52.21(k)(1). With respect to new major stationary sources, BACT will be required for each regulated pollutant emitted in excess of specified *de minimis* amounts. Application of BACT is also required, in the case of major modifications, for each regulated pollutant emitted for which there is a significant net emission increase (greater than *de minimis* amounts) at the source. The BACT requirement applies to only the modified units and added units at the source whose construction results in a source-wide significant net increase in the emissions of the regulated pollutant. The new BACT requirements apply only to the owner or operator of a PSD source or modification whose application for a PSD permit was not complete before today's promulgation. (*See* Transition).

The *de minimis* emissions rates promulgated by the Administrator (*see De Minimis* Exemption) will apply to both BACT and LAER requirements. The Agency specifically solicited comments on the need to specify *de minimis* levels for BACT, since the case-by-case BACT determinations would presumably take *de minimis* levels and such related issues as cost into account. Twenty-six commenters addressed this issue. Seventeen agreed in principle but generally considered the proposed levels too low and requested special consideration for pollutants emitted in less than major amounts. Eight of nine dissenters preferred case-by-case BACT determinations, with no *de minimis* values.

The Administrator is implementing the proposed *de minimis* approach for determining BACT applicability, although several values have been increased. (*See De Minimis* Exemptions.) This action should alleviate the concerns of those commenting about the need for BACT review of those pollutants emitted in small amounts. The Agency also solicited comments on the potential problem of a source obtaining lenient BACT determinations and later applying better controls to offset additional expansion plans. Twelve of thirteen commenters addressing this issue concluded that no such problem would arise. They claimed that it would be implausible to suppose that state programs and EPA regional offices would evade such responsibility, especially since loose BACT determinations would result in accelerated consumption of increment. The Administrator agrees that there appears to be adequate protection against loose BACT determinations.

Each of the three comments that addressed a need to phase in the BACT requirement favored a six month to one year grace period because of the complexity of the program. However, the Administrator believes that the case-by-case flexibility of BACT determinations is sufficient to phase in these regulations. Moreover, sources have effectively had a one year notice, in that the original *Alabama Power* decision, published June 18, 1979, informed them of the new BACT requirements. (*See* Transition.)

An additional issue, regarding the pollutant applicability of the BACT requirement, arose during the comment period. The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source. However, the proposal could be interpreted as requiring BACT for certain pollutants where the

Administrator did not intend to require BACT. For example, the proposal could be interpreted as requiring BACT review for any pollutant emitted from a source that was modified, regardless of whether the emissions of the pollutant increased. However, that was not the Agency's intent.

If a new unit were added or if a modification were made to a unit at a source, but there are contemporaneous decreases in emissions elsewhere at the source, BACT is required only for the pollutants for which there is a net significant plant-wide increase. For example, consider the addition of a boiler whose emissions of PM, SO_2, and NO_x each exceed *de minimis* levels. If, at the same time, an emission unit of SO_2 elsewhere at the source were shut down, such that plant-wide emissions of SO_2 either do not increase or increase by less than a *de minimis* amount, BACT is required for the new boiler only for PM and NO_x. Of course, BACT will not be required if there is no significant plant-wide increase in emissions of any pollutant. Similarly, if an existing emissions unit of a source were modified such that there is an emissions increase for one or more pollutants, but not all, BACT is required only for the pollutants for which there is both a net increase at the unit and a net significant plant-wide increase.

The above final policy governing the applicability of BACT to modifications is also consistent with existing policy under section 111, which the court said should govern modification concerns. The applicable regulation, 40 CFR 60.14(a), states that "any physical or operational change to an existing facility which results in an increase in the emissions rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility *for each pollutant to which a standard applies and for which there is an increase in the emissions rate* to the atmosphere." (Emphasis added.)

The regulation cited above makes two important statements about the applicability requirements. First, the BACT requirements apply only with regard to those pollutants for which there has been a net significant increase. This was emphasized by the Alabama Power decision: "Congress wished to apply the permit process, then only where industrial changes might increase pollution in an area, not where an existing plant changed its operations in ways that produced no pollution increase * * *. The interpretation of 'modification' as requiring a net increase is thus consistent with the purpose of the Act * * *. The EPA has properly exempted from best available control technology (BACT) and ambient air quality review those 'modifications' of a source that do not produce a net increase in any pollutant." 13 ERC at 2043.

Second, BACT is required for net significant increases of *any* pollutant regulated under the Act, regardless of the category of source involved or the emissions standards generally applicable to it. Section 165(a)(4) of the Act requires application of BACT "for each pollutant subject to regulation under this Act" emitted from a subject facility. 42 U.S.C. 7475(a)(4). This includes not only criteria pollutants but also all pollutants regulated under NSPS or NESHAP. In this manner, BACT can complement the NSPS process by extending coverage to additional source types and units and perhaps identifying candidates for future NSPS and NESHAP regulations.

XVI. Monitoring

In *Alabama Power*, the court held that section 165(e)(1) of the Act requires an ambient air quality analysis for each pollutant subject to regulation under the Act that a proposed source or modification would emit, prior to applying for a PSD permit. Since existing PSD regulations require monitoring only for criteria pollutants emitted in major amounts, EPA responded to the June 18, 1979 *per curiam* opinion by proposing to require, for criteria and noncriteria pollutants, an air quality analysis that would generally include monitoring data. In order to gather and analyze the appropriate data necessary to apply for a PSD permit, a proposed source would have to establish an appropriate monitoring network or would have to gather and analyze representative air monitoring data resulting from ongoing monitoring activities.

As proposed, preconstruction monitoring data was required as part of the air quality analysis when: (1) the estimated ambient impact of any new pollutant emissions from the stationary source or modification would be larger than the pollutant specific *de minimis* air quality concentration (Table B); or (2) the new emissions or net emissions increases for the pollutant would be major (100/250 tons per year). In addition to this rule, EPA proposed that a case-by-case analysis of the proposed stationary source or modification which would impact on a Class I area be conducted even though the anticipated impact would fall below the *de minimis* level. Later, in October 1979, EPA provided further guidance for applying these requirements in the draft revision of the *Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)*, OAQPS 1.2-096, U.S. EPA, Office of Air Quality Planning and Standards and Office of Research and Development, RTP, NC 27711.

The proposal stated that certain noncriteria pollutants (sulfuric acid mist, carbon disulfide, carbonyl sulfide, methyl mercaptan, dimethyl disulfide, and dimethyl sulfide) were lacking measurement methods approved by EPA. Until such time as approved techniques would become available, the Agency proposed to use mathematical modeling to estimate the air quality resulting from the emissions of these pollutants. Considering these limitations and the general lack of experience in monitoring on a routine basis, the Administrator proposed to implement noncriteria pollutant monitoring requirements on a case-by-case basis.

In addition to the pre-application monitoring requirements already described, EPA's proposal included discretionary authority for requiring post-construction monitoring to determine the effects of the new emissions on existing air quality. For cases in which larger pollutant emission impacts are anticipated, post-construction monitoring can be a particularly useful aid in adjusting modeling results used to predict concentrations resulting from the source's operation. The approach was thought to be responsive to the *Alabama Power* decision which required EPA to use monitors to help refine modeling techniques. Accordingly, EPA proposed to generally require post-construction monitoring from large sources of particulate matter and sulfur dioxide. Other sources whose emissions are estimated to result in air quality levels approaching an allowable increment or a NAAQS could also be required to submit post-construction monitoring data. The rule promulgated today is consistent with the proposal.

The Administrator believed that the required monitoring data would be most productive in checking the accuracy of models and, in some cases, could be used to calculate increment consumption. If an applicant or other party believes that a model required by EPA had either overpredicted or underpredicted the air quality impact of a source, EPA stated that monitoring data would be evaluated to the extent possible to determine whether adjustments would be necessary. EPA anticipated that the future development of more sophisticated monitoring

techniques may permit increased use of monitoring data to track increment consumption and establish ambient baselines, as well as improve the level of confidence in modeling.

Lastly, EPA considered the approach needed to smoothly usher in the new monitoring requirements. The September 5 Federal Register indicated that EPA intended to require any additional monitoring requirements, as now necessary under *Alabama Power*, to be phased in. Later, in October 1979, the draft ambient monitoring guidelines specified that a three-month allowance would be subtracted from the time interval over which the owner must monitor to allow for procuring and setting up the necessary monitoring equipment. (*See* Transition).

There was a large response to EPA's proposal and draft monitoring guidelines—nearly 100 public comments and over 800 requests for the guidance document were received. The comments indicated general agreement with EPA's interpretation of the court's preliminary opinion. But some concern was expressed over certain specific portions of the proposal: (1) the limited technology available to monitor the noncriteria pollutants in the ambient air; (2) the large cost associated with gathering all the required air quality data for all regulated pollutants; (3) the identification process for "representative" data; and (4) the need for post-construction monitoring.

Subsequent to the publication of the September 5, 1979 proposal and the receipt of the public comment, the court issued its final decision on December 14, 1979. One important change the court made upon reconsideration of the June 18 opinion was "that section 165(e)(1) requires that *an analysis* be conducted, and that it be conducted for each pollutant regulated under the Act. But * * * that section 165(e)(1), standing alone does not require monitoring as *the* method of analysis to be employed in the fulfillment of its requirements." 13 ERC 1993, 2019. This ruling gave EPA more flexibility in defining the minimum requirements for a proper analysis of the noncriteria pollutants. "EPA might * * * choose *either* monitoring or modeling as the method of analysis * * *" *Id.* In other monitoring issues the court essentially affirmed its preliminary opinions.

Today, the Administrator is promulgating the proposed monitoring requirements with the noted exceptions. (*See* 40 CFR 51.24(m), 52.21(m)). EPA will generally require one year's worth of monitoring data as part of the air quality analysis for only the criteria pollutants. For the noncriteria and hazardous pollutants, modeling, not monitoring, will be the mechanism used to perform most detailed air quality analyses. However, there may be certain circumstances where monitoring may be the only option available to perform an adequate analysis for the noncriteria pollutants (e.g., when little or no data on emission inventories for the area of concern exist). In that case, EPA will require ambient monitoring for the noncriteria pollutants if there is an acceptable method for the monitoring of that pollutant. Presently, the Administrator has acceptable methods for measuring ambient concentrations of: (1) all the criteria pollutants; (2) mercury; (3) beryllium; (4) vinyl chloride; (5) fluorides; and (6) hydrogen sulfide. A list of acceptable methods and copies of the method description are available by writing to: U.S. EPA, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD–77), Research Triangle Park, N.C. 27711. Also, techniques to measure ambient total reduced sulfur and reduced sulfur compounds have been chosen and will be added to the list within the next several months. At this time there are no acceptable methods for measuring ambient levels of asbestos and sulfuric acid mist.

As EPA gains more experience from the PSD program with respect to noncriteria pollutant analysis and as the technology develops, the Administrator will consider an increased role for ambient monitoring within the required air quality analysis.

In addition to the exemptions given in the *de minimis* section of this Federal Register publication, EPA may not always require a source owner to establish a monitoring network when the data would not validate or improve the estimates made by the mathematical models. When the existing air pollution levels are conservatively estimated to be quite small and a monitoring network could not reliably measure the predicted background concentrations, EPA will generally not require the source owner to generate preconstruction monitoring data. Also, if the source owner has submitted preconstruction data for the source site, and the post-construction monitoring network could not measure a predicted degradation in the air quality, then EPA will generally not require the source owner to collect further monitoring data. More guidance for meeting all the monitoring requirements is given in the *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (PSD), EPA–450/4–80–012, July 1980, available from the Monitoring and Data Analysis Division, OAQPS, (MD–14), U.S. EPA, Research Triangle Park, N.C. 27711.

In the September 5, 1979 proposed regulations and the October 1979 draft of *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (PSD), EPA solicited comments on the use of representative air quality data to satisfy PSD monitoring requirements. Thirty-nine comments were received on the various aspects of the use of representative air quality data. The major responses were as follows: twenty-four commenters supported the use of existing representative air quality data, especially for remote areas. Five commenters wanted EPA to allow the use of bubbler data in lieu of continuous monitoring data, seven respondents believed that data older than two years should be allowed, and three objected to the quality assurance requirements for the representative data.

EPA has considered all of the comments and has taken the following actions:

(1) The use of existing representative air quality data will be permitted in lieu of monitoring, provided that the data meet the criteria in the above reference guideline.

(2) No bubbler data will be permitted because the data should be of the same quality as that obtained if the applicant monitored according to the requirements in the above referenced guideline. This guideline specifies monitoring must be done with continuous instruments to eliminate measurement biases associated with bubbler data. Continuous measurements are also more suitable for routine monitoring purposes in checking for compliance with short-term standards.

(3) EPA will allow the use of data, for preconstruction purposes only, collected in the three-year period preceding the permit application provided reference/equivalent quality assurance procedures were followed during the measurement period. The draft guideline has previously specified a two-year requirement.

(4) EPA reaffirms the intent that all monitoring data collected must have been collected in accordance with acceptable quality assurance procedures. The specifics of the minimum quality assurance program needed for collecting air quality data are contained in the referenced guideline.

Finally, the court held that EPA had failed to provide concrete guidance to the states for designating when less than one year of monitoring data would meet the required air quality analysis, as specifically allowed under section 165(e)(2). Such guidance is given under

PSD SIP Revisions located elsewhere in today's Federal Register publication.

XVII. Notification

The proposal contained a requirement that certain construction projects exempt from PSD permit rules file a report at least 90 days in advance of the time that the exempted construction would commence. Notification requirements similar to those in the PSD proposal were also included in the proposed nonattainment rules, under 40 CFR 51.18(j) and 52.24, and Appendix S of Part 51 (the Emission Offset Interpretative Ruling). These notice requirements would apply to source construction which would not be subject to NSR solely because (1) the increase in emissions was offset by a contemporaneous decrease so as not to cause a significant net increase at the source (*see* Modification), or (2) the application of air pollution controls not generally required by the applicable SIP or 40 CFR 60 or 61, would lower the "potential to emit" of the source below the applicable threshold for permitting. The proposal would have required the submittal of comprehensive data for both new and existing emissions units at the stationary source and all other information needed by the reviewing authority to determine if the exemption reported by the source was proper. No formal applicability determination, however, was to be made and no major delays in the construction program of any such source were intended.

The Administrator believed such reporting was necessary because of the additional complexity of such determinations and the decreased number of sources subject to PSD due to changes in applicability rules. A need was apparent to record unreviewed emission increases and reductions occurring years apart at the same plant, in order to assess their impacts on air quality as well as to simply register in advance claims for reduction credits. For these reasons the Administrator proposed to use his authority under section 114 to monitor these determinations of offsetting emissions reductions and increased control efficiency. Section 114 authorizes the Administrator to require a source owner to provide such information as he may reasonably require in order to carry out Part C of the Act or to determine if a source owner is in violation of a SIP requirement.

Fifty-nine comments were received on the notification requirements. Only two comments completely supported the Agency proposal. Thirty-eight of the commenters felt that the requirements were unnecessary and not authorized by the Clean Air Act. Many stated that the requirements were burdensome and equivalent to a preconstruction permit process. Twenty-four commenters specifically stated that section 114 does not allow such a comprehensive data gathering requirement, although reasonable data gathering is allowed.

Those who thought the requirements unnecessary cited the adequacy of existing state permitting programs to deal with these problems and the possibility of post-construction recordkeeping to accomplish the same objectives. EPA was advised to take enforcement action against the few source owners who would incorrectly exempt a source from review and then construct the source without obtaining a permit, rather than risk pervasive construction delays of properly exempted sources. Many commenters felt that the administrative burden to both the reviewing agency and the source outweighed its benefits. Seventeen commenters specifically stated that the extra cost to source owners would remove the real incentives for early cleanup and would act to perpetuate the operation of older units with high air pollutant emissions.

The Administrator maintains that reporting similar to the preconstruction notice is needed and can be required under section 114. However, the comments, particularly those concerning the potential of existing state programs to accomplish this function, have caused EPA to reconsider the need at this time for a preconstruction notification requirement. State comments and meetings with several state representatives in Atlanta (*see* Docket account of III–D–4) indicate that all states currently learn of all proposed emission units and changes before such would commence construction. Most states acquire such knowledge through their existing general NSR procedures, approved under 40 CFR 51.18, even if a net decrease would occur at the source. Other states learn of proposed emission increases through notification letters filed by the source pursuant to a formal applicability determination.

Many states do not routinely require sources to record emission decreases, especially when such would occur well in advance of related emission increases. While a preconstruction notice would be desirable to document these decreases, the requirements for contemporaneous emission reduction credit (*see* Modification) are sufficient to fulfill this need. That is, emission reductions, in order to be creditable in offsetting any contemporaneous increase at the same stationary source, must be enforceable before the associated unit(s) with the emissions increase(s) commence construction. Such reductions, to be enforceable, must generally be made part of an enforceable operating or construction permit or be processed as a formal SIP revision. Although the Administrator is still concerned that sufficient information may not be available when a source owner wishes to document previous emissions reductions, he is opting for a "wait-and-see" approach in order to alleviate the concerns of the majority of the commenters who felt the notification requirements were unjustified and burdensome.

Also, since states will soon be administering the PSD program, it is best to allow them the flexibility to integrate notification requirements into their existing permit programs. The notification requirements in each state will be different, depending upon whether the state has an emission banking system and how it operates, the type of emission inventory system, and the information available from operating and construction permits. PSD increment tracking systems will also be set up by states, which can tailor informational requirements to their own tracking systems.

While today's regulations do not contain a formal preconstruction notice requirement, owners and operators are hereby put on notice for the following: (1) Sufficient records regarding the details of contemporaneous emission increases and decreases or applicable source determinations of "potential to emit" should be maintained so as to verify that no permit was required should the Administrator so require under section 114; (2) If experience in implementing the "no net increase" provisions of PSD applicability indicates that a more comprehensive notification system is required, the Administrator will promulgate an amendment to PSD and nonattainment regulations similar to the deleted provisions of the September 5 proposal; and (3) Any source which improperly avoids review and commences construction will be considered in violation of the applicable SIP and will be retroactively reviewed under the applicable NSR regulation.

XVIII. PSD SIP Revisions

Comments have been solicited on three aspects of the development of acceptable PSD plans by states. The issues are: (1) the authority of states to submit different but equally effective PSD programs, (2) state flexibility in defining baseline areas, and (3) state flexibility in allowing monitoring exemptions.

A. *Equivalent State Programs.* Under existing regulations, the Administrator cannot approve proposed state PSD regulations unless the state requirements are identical to or individually more stringent than the corresponding 40 CFR 51.24 regulations. While the Act does contain specific requirements for several major aspects of PSD programs, it does not prohibit states from using, in other areas, approaches equivalent to those of the federal regulations in order to meet the statutory objectives. Accordingly, the Administrator proposed on September 5, 1979 that states be given some flexibility in preparing PSD plans. The Administrator requested comment on such an approach and suggested portions of the PSD requirements for which equivalent approaches might be acceptable, and others for which alternative regulations would not be approvable. Where SIPs were allowed to differ, a test of overall equivalence was to be used based on the ability of the state system to capture as many emissions as would the 40 CFR 51.24 regulations.

All forty-nine comments on this topic strongly endorsed the general approach of giving states flexibility in developing PSD programs, although several commenters expressed the desire for a more extended area for SIP flexibility. Among those areas are: (1) the entire PSD program, (2) fugitive dust applicability, (3) modeling techniques, and (4) treatment of minor modifications and exempted sources. Another commenter asserted that EPA could hold the states responsible only for plans that addressed minimal requirements, such as maximum increment consumption.

After consideration of the comments, the Administrator has decided to treat PSD SIP revisions generally in the manner proposed. This means that states will be permitted to meet the following requirements of 40 CFR 51.24 with different but equivalent regulations, or implement the federal regulations with considerable discretion:

a. Baseline area.

b. Type and amount of data needed for monitoring purposes.

c. Temporary exclusions from increment consumption.

d. Defining "contemporaneous" as a reasonable period that may be greater or shorter than 5 years.

e. Banking of emissions reductions for future offsets.

f. Source information and analysis required of the applicant.

g. Public participation after providing the opportunity for public hearing.

h. Alternatives to first-come-first-served permit processing.

State PSD programs must follow the federal regulations in other matters. This includes, but is not limited to the following:

a. Maximum allowable increments.

b. Modeling techniques.

c. Class I area protection.

d. Notice to the Administrator or the applicable Federal Land Manager for prospective permit actions.

e. New (grass roots) major stationary source applicability.

f. NSPS, NESHAP minimum requirements for BACT determinations.

g. Definitions generally as contained in 40 CFR 51.24(b). (State definitions need not be verbatim translations, but must have the same effect).

The Agency is not expanding the area of state program flexibility to those four areas, noted earlier, that were suggested by the commenters. First, the Administrator does not believe that complete program flexibility is allowable under the Act, nor does he find a basis for the comment that EPA is without authority to require that SIPs include more than skeletal program components. The second suggestion, regarding fugitive dust, is not feasible at this time for reasons detailed elsewhere (*see* Fugitive Dust Exemption). With regard to the third comment, the Act specifically directs the Administrator to specify air quality models. Section 165(e)(3), 42 U.S.C. 7475(e)(3). In addition, national consistency is important for such air quality impact analysis in order to standardize how increment would be consumed or enhanced across the country.

With regard to the degree of state flexibility in exempting additional types of new and modified sources, EPA believes that adequate exemptions have been provided in today's regulations and no further ones are authorized under the Act. The Administrator wishes to note that today's rules allow a state the opportunity to change the time period defining contemporaneous emissions increases. This change affects the definition of major modification and thereby affects the number of PSD reviews.

The opportunity for states to change the time period within which emissions changes would be considered contemporaneous is not constrained by a test of equivalency. Rather, it should be considered by states in developing PSD SIPs in conjunction with their deliberations on alternatives to first-come-first-served permitting and emission offset banking. The Administrator believes these issues are related to the state's inherent flexibility under the Act to manage increment consumption.

B. Baseline Area

This aspect of the equivalent state program issue deals with the definition of the area for which the baseline date is triggered by a PSD permit application and, specifically, with whether this definition must be the same under a PSD SIP as it is in 40 CFR 52.21. The proposal defined baseline area for both 40 CFR 51 and 52 as every part of an affected AQCR designated attainment or unclassified on the baseline date. Comments were solicited concerning the desirability of allowing states to define "area" as any *portion* of an AQCR that had been designated as attainment or unclassifiable, or, conversely, to allow states to define "area" as the entire state.

All commenters specifically addressing the issue of allowing states to have flexibility in defining baseline area were in favor of that approach. Many were more specific, suggesting that 107 designated areas or source impact areas be used.

The Administrator has decided to allow flexibility to states, not by accepting alternative definitions in SIPs, but by defining baseline area in such manner as to allow flexibility. This change in definition arises from a revised legal interpretation of what meaning "area" may be given under the Act. (*see* Baseline Concentration). Baseline area is now defined as all areas (and every part therein) within the state that are designated attainment or unclassified under section 107(d)(1) (D) or (E) of the Act in which the source establishing the baseline date would locate or would have an air quality impact equal to or greater than 1 $\mu g/m^3$ (annual average) for the pollutant (SO_2 and/or TSP) for which the baseline date is established. Flexibility is inherent in state authority to redesignate areas under section 107. Thus, large tracts of land belonging to one clean or unclassified PSD area can later be divided into several smaller PSD baseline areas with potentially different baseline dates. Other than the limitations associated with processing 107 area redesignations as SIP revisions, EPA requires that area redesignations under section 107 cannot intersect or be smaller than the area of impact of any major stationary source or major modification which establishes a baseline date or is subject to PSD and would be constructed in the same state as the state proposing the redesignation. A baseline date will, therefore, be triggered for the entire designated section 107 area unless nonimpacted portions are redesignated to smaller areas.

This approach allows the flexibility requested by the commenters, but precludes "postage-stamp" designations designed to trigger baseline only in the immediate vicinity of the source. It also avoids the difficult area boundary problems which would arise from defining area as the PSD source impact area. States are cautioned to carefully weigh any inclination to postpone baseline dates through area redesignations against increased difficulties associated with tracking increment consumption.

C. State Monitoring Exemption

Alabama Power remanded to EPA that portion of the monitoring requirements which allowed states to accept less than one year of preconstruction monitoring data for cases in which a shorter period would be sufficient to perform a complete and adequate analysis. The court ruled that EPA had not provided adequate guidance to the states for making this determination. 13 ERC 1993, 2020.

The proposal contained concrete guidance for use by states in determining if less than one year of monitoring data is sufficient. That guidance provided that as little as four months of monitoring data for the criteria pollutants was acceptable if the applicant demonstrated that the maximum pollutant concentrations would occur within that time.

Fourteen comments were received on various aspects of this proposal. Thirteen commenters supported the flexibility of requiring less than one year of monitoring data under specified circumstances. Two commenters addressed ozone monitoring requirements where there were more than four months with average daily maximum temperatures greater than 20°C (68°F).

The Administrator has decided to promulgate the proposed regulations except for the following:

(1) Less than one year of monitoring data will be permitted for all regulated pollutants, rather than for just the criteria pollutants. However, it must be demonstrated through historical data or dispersion models that the data for such shorter periods of time, but not less than four months, will be obtained during a time period when maximum air quality levels can be expected.

(2) Guidance for monitoring ozone during the warmest four months of the year has been deleted. Monitoring for ozone, as well as other pollutants, will still be required during the time period when maximum air quality levels can be expected. Ozone concentrations will generally be higher during the warmest four months of the year. However, ozone monitoring must also be conducted when the yearly maximum ozone concentrations are likely to occur during months other than the warmest four months of the year. This will ensure that ozone monitoring will cover the expected maximum concentrations.

XIX. Additional Issues

A. Innovative Technology

In the September 5, 1979, Federal Register the Agency proposed a new paragraph (u) which sets out specific requirements for reviewing sources that wish to utilize innovative control technologies. The new paragraph sets out criteria to be used by the Administrator in determining whether a proposed control technology is innovative, in addition to establishing specific provisions for implementing the BACT and modeling requirements.

All of the commenters recognized the need to encourage the development of technology and generally approved of EPA's approach. One large environmental group commented that while it approved of the added flexibility in specifying BACT for innovative technologies, it was concerned that Class I areas might be compromised if increment violations were allowed to occur during the period of testing. We share this concern of the environmental group and are today promulgating a regulation which ensures full protection of Class I areas.

Today's amendments provide that, for a source whose technology has been designated as "innovative" by the Administrator, the BACT requirement should insure the installation of the innovative system and the adoption of a compliance schedule for meeting a final emission limitation. This final emission limitation must at least represent the BACT level that would have been initially defined under § 52.21(j), assuming the use of proven state-of-the-art technology. The compliance schedule may extend no more than 7 years after permit issuance or 4 years after startup of the source. The regulations also provide that the Administrator may withdraw his approval if a source: (1) fails to meet the final emissions limitation by the specified date, (2) fails to protect the public health, welfare, or safety, or (3) shows an indication that the innovative control system will not be successful. The source will then be given a period of no more than 3 years to come into compliance with the BACT level determined with the use of the demonstrated system of control.

The September 5 Federal Register proposed that with the consent of the governor an "innovative technology" source could conduct the increment impact analysis using the final emission limitation specified in the permit, provided that no interference with applicable NAAQS would result during the interim period. EPA reasoned that any increased level of emissions which might occur during the interim period would be temporary and would not significantly impact the increments. However, one of the commenters pointed out that Class I areas require protection even from temporary violations. We agree with the concerns of this commenter and cite § 52.21(i)(7) in their support. That section exempts temporary sources from the modeling requirements except when they impact Class I areas or areas where the increment is known to be violated. Today's regulations allow an "innovative" source to use its final emission limitation for increment modeling purposes, but only if there is no impact on any Class I area or any area with a known increment violation. As in the proposal, the final rules requiring modeling for the purpose of evaluating the impact on NAAQS must take into account interim emission projections. Under no condition may a source be approved if it would cause a violation of the NAAQS, even a temporary violation.

B. Modified Permits

In the September 5, 1979 Federal Register, EPA proposed to add a new paragraph (t) entitled "Modified Permits." The new paragraph provided a simplified approval procedure for sources that make minor changes in design capacity or in the nature of process equipment between the time they obtain a PSD permit and the time they complete construction. It also required prior approval, through permit modifications, of increases in hours of operation.

The comments on this section were mixed. Some commenters felt that the new paragraph was redundant and superfluous, while others generally approved of it but asked for clarification. Upon further consideration, the Agency believes that there is a need to distinguish between situations in which permits would be changed for primarily administrative reasons, such as a change to reflect a revised construction schedule, and situations in which the permit change involves a significant increase in emissions. In the latter case a new permit must be issued; in the former, however, an abbreviated procedure involving modification of the permit might be preferable. There are numerous issues to be considered in implementing

such an approach. These include the means to differentiate between significant and nonsignificant changes, and the specific procedural requirements for modifying a permit. Those issues were not adequately addressed in the proposal and for that reason the Agency has decided that it does not have a sufficient basis for completing rulemaking at this time. However, further rulemaking is being considered for future proposal and comment will be requested on the issues at that time.

C. Nonprofit Institutions

EPA proposed on September 5 to exempt modifications of nonprofit institutions from PSD review requirements as is already done for new construction of this type. This would mean that, upon written request by the governor of the state, a PSD permit would not be required of a major stationary source or major modification that qualifies as a nonprofit health or educational institution. Today the Administrator promulgates this exemption as proposed since no signficant public comment was received. It should be noted that although such major new or modified sources would not require a PSD permit, the emissions from these sources would consume the applicable PSD increment(s) after January 6, 1975.

D. Portable Sources

With regard to portable sources, EPA proposed to change the 30 day notice to a 10 day notice for previously permitted PSD sources wishing to relocate. Based on experience in implementing the PSD regulations, and having received no adverse public comments on this proposal, the Administrator is adopting this proposal with one exception. Sources with PSD permits must provide a notice to the reviewing authority not less than ten days before relocation activities would commence, unless the Administrator has previously approved a different minimum time for relocation notice.

The Administrator would also like to clarify that a source is portable only if it would have temporary location and temporary emissions. Existing EPA policy defines temporary emissions as emissions from a stationary source that would be less than two years in duration, unless the Administrator determines that a longer time period would be appropriate. Thus, for a portable source to qualify for the above exemption, it must typically be located at the new location less than two years.

E. Secondary Emissions

Desiring to make the PSD review requirements similar to nonattainment requirements wherever possible, the Administrator proposed to add the definition of secondary emissions found in the offset ruling (44 FR 3274) to the PSD regulations. *See* 43 FR 26403. Secondary emissions would mean emissions from new or existings sources which occur as a result of the construction and/or operation of a major source or major modification, but do not necessarily come from the source itself. Secondary emissions would include:

(a) emissions from ships or trains coming to or from a source or modification; or

(b) emissions from offsite support sources which would otherwise increase emissions as a result of construction or operation of a major source. Although reasonably quantifiable secondary emissions would be reviewed in the air quality anaylsis, such emissions would not be included in determining "potential" emissions.

Public reaction to the September 5, 1979 proposal and the final *Alabama Power* opinion regarding EPA's treatment of secondary emissions was small. Generally the commenters favored the exclusion of secondary emissions from the PSD permit process altogether. Their objections centered on the availability and reliability of the emission factor data to "reasonably" quantify secondary emissions. Also the possibility of redundant reviews was highlighted by several commenters. The Administrator, in weighing these comments, has decided to promulgate the regulations addressing secondary emissions as proposed on September 5, 1979. *See* 40 CFR 51.24(b)(3), 52.21(b)(3), 51.24(b)(20), and 52.21(b)(20).

The Clean Air Act clearly calls for a detailed and extensive air quality impact assessment. For instance, each permit application must include impacts from the growth projected in the area that would occur as a result of the proposed source's construction. *See* section 165(a)(6). Also, once the baseline date is set, such emissions would consume the maximum allowable increments, so each permit decision must give consideration to all the possible ramifications of allowing a source or modification to construct. *See* section 165(a)(3) ("cause or *contribute*"). Secondary emissions must be considered when those emissions are specific, well defined, reasonably quantifiable, and impact the same general area.

F. Baseline for Calculating Offsets Under Section 173(1)(A)

The Offset Ruling sets out rules and guidance for determining the baseline for calculating emissions offset credit, as well as guidance on the location of offsetting emissions. *See* 40 CFR Part 51, Appendix S, Sections IV.C. and D. To aid the states in developing their NSR regulations for nonattainment areas, or in revising those regulations, EPA has decided to promulgate those rules and guidance in § 51.18(j)(3).[14] The langauge promulgated today is identical to that used in the Offset Ruling, except as explained below.

On January 16, 1979, EPA modified the Offset Ruling to conform to section 129(a)(1) of the Act by setting the baseline for determining emissions offset credit at the emissions level specified for the source in the applicable SIP. EPA is retaining this baseline level for the Offset Ruling. However, the approach for NSR programs adopted pursuant to section 173 is slightly different. Section 173(1)(A) sets the baseline as the "allowable" emissions of the source, but it further specifies that the offsets obtained by the source must be sufficient to represent reasonable further progress (RFP). Some Part D SIP revisions approved by EPA have demonstrated attainment and RFP based on the allowable emissions of sources in a nonattainment area. However, many Part D SIP revisions have based their demonstrations on the *actual* emissions of the sources in a nonattainment area, rather than the sources' allowable emissions. This means that to be consistent with RFP, sources must reduce their actual, rather than their allowable, emissions. Otherwise, sources could claim credit for offsets in situations where the offset would actually interfere with RFP.[15]

To accommodate the different approaches to RFP, EPA has provided that the baseline for determining emissions offset credit shall be the

[14] On January 16, 1979, EPA solicited comments on certain aspects of the Offset Ruling, none of which directly concerned the matters published today. EPA will respond to those comments after today's promulgation.

[15] For example, suppose a source's allowable emissions are 1,000 tpy, and its actual emissions are 500 tpy. Now suppose it wants to add a new emissions unit, thereby adding 100 tpy, and the SIP requires a 100 tpy reduction for RFP. The source might achieve both objectives by decreasing its total allowable emissions to 900 tpy, i.e., it adds the 100 tpy for the new facility, but makes other reductions in allowable emissions of 200 tpy. This is adequate if the RFP demonstration relies upon allowable emissions, since the source started at 1,000 tpy and now is at 900 tpy. But if RFP is based on actual emissions, then there is a *loss* of 100 tpy, because RFP assumed 500 tpy and now the source emits 600 tpy.

allowable emissions of the source, where the SIP relies upon allowable emissions to demonstrate RFP; but the baseline must be actual emissions where the demonstration is based on reductions in actual emissions. EPA believes for the reasons discussed above that this approach is necessary to assure RFP towards attainment of ambient air quality standards.

G. Economic Impact Assessment

In the September 5 proposal, it was stated that the Agency would prepare an economic impact assessment of the proposed changes after the final court opinion was issued, which took place on December 14, 1979. The Agency further indicated that it would make the report available for public comment prior to promulgation, and that any resulting comments would be taken into account in the promulgated regulations.

Although the results of the impact assessment released today have been considered in developing the regulations, primarily for understanding *de minimis* effects, it has not been possible to complete the assessment in time to get comments prior to promulgation. In fact, because of the inherent complexity of the program, it has not been possible to do a true economic impact assessment (*i.e.*, one which considers impacts on market positions, prices, closures, etc.).

The document made available today presents as assessment of the overall impact of the proposed regulations with respect to several of the major issues or changes in the proposed regulations. The assessment does not attempt to quantify the impact of every issue nor does it attempt to assess the overall impact associated with the implementation of the PSD regulations in general. It is designed to provide a relative assessment of the impact of the September 5 proposal versus the June 1978 regulations in terms of the: sources to be affected, their associated emissions, major requirements which must be met (or which are no longer required to be met), and estimated cost savings for sources no longer subject to PSD review as a result of the proposed regulations. In short, the analysis provides an estimate of differential cost impact of the 1978 versus the proposed PSD regulations and an assessment of the major issues associated with the proposed PSD regulations.

As noted, the assessment focused on the difference between the June 1978 regulations and those proposed on September 5. However, there are significant changes in the promulgated regulations compared to those proposed, especially with regard to the *de minimis* values. Since these values have a major impact on expected cost, a projection of the impact of the final regulations was also made.

It is estimated that there will be a savings as a result of the promulgation for sources which would have been subject to the old regulations but which would not be subject to the new. This would represent an annual savings of $2.2 to 6.1 million assuming the sources which have received permits from April 1978 to November 1979 are representative of those which will receive permits in the future.

Although there is an overall savings for sources which would not longer be subject to PSD review, the new regulations require more extensive review for some sources, as well as review of sources which were not previously covered; that is, modified sources with uncontrolled emissions of less than 100 or 250 tons per year but which have controlled emissions greater than *de minimis*. Since these sources are not now subject to PSD review, they would be required to prepare a PSD permit, conduct the necessary air quality impact assessments, incur some delays in construction as a result of undergoing PSD review in addition to state NSR review, and install BACT instead of just meeting the emissions limits required by the State Implementation Plan or New Source Performance Standards as applicable. As a result of the additional cost incurred because of more extensive review and by the sources not currently subject to PSD, the overall effect of the promulgated regulations (including the savings described above) is an increase of approximately $12.4 to 24.5 million per year.

The complete analysis is contained in the document entitled *Regulatory Impact Assessment for the September 5, 1979 Proposed Prevention of Significant Deterioration Regulations*, EPA-450/2-80-073. This document is available for inspection in the rulemaking docket. Copies may be obtained by writing to the Air Information Center, U.S. EPA Library Services, (MD-35), Research Triangle Park, NC 27711.

H. Consolidated Permit Regulations

As mentioned in the section on TRANSITION, EPA recently promulgated regulations, known as the Consolidated Permit Regulations, which now generally govern the processing of applications for permits under Part 52 PSD regulations. Among the regulatory amendments announced here are three minor changes to the Consolidated Permit Regulation. First, EPA has deleted the substantive language of 40 CFR 124.3(b) and put "Reserved" in its place. Section 124.3(b) related primarily to the 50-ton exemptions of the 1978 Part 52 regulations. With the deletion of those exemptions, § 124.3(b) would have become superfluous. Second, EPA has conformed 40 CFR 124.5(g)(2) to the numbering in the new Part 52 regulations. Finally, the agency has corrected 40 CFR 124.42(b) by substituting "submitted" for "requested."

Final Action

The following regulatory amendments are nationally applicable, and this action is based upon determinations of nationwide scope and effect. Therefore, under section 307(b)(1) of the Act, judicial review may be sought only in the United States Court of Appeals for the District of Columbia Circuit. Petitions for judicial review must be filed on or before October 6, 1980.

(Sections 101(b)(1), 110, 160-169, 171-178, and 301(a) of the Clean Air Act as amended (42 U.S.C. 7401(b)(1), 7410, 7470-7479, 7501-7508, and 7601(a)); Section 129(a) of the Clean Air Act Amendments of 1977 (Pub. L. No. 95-95, 91 Stat. 685 (August, 7, 1977)))

Dated: July 31, 1980.

Douglas M. Costle,

Administrator.

State Plans For New Source Review For PSD Purposes

1. Section 51.24 of Title 40 of the Code of Federal Regulations is amended by deleting paragraph (k) and redesignating paragraphs (l) through (s) as (k) through (r) and then by revising paragraphs (a)(2), (b), (f), (i)-(k), (m) and (r) and adding new paragraphs (a)(6) and (s) to read as follows:

§ 51.24 Prevention of significant deterioration of air quality.

(a)(1) *Plan Requirements*

* * * * *

(2) *Plan Revisions.* If a State Implementation Plan revision would result in increased air quality deterioration over any baseline concentration, the plan revision shall include a demonstration that it will not cause or contribute to a violation of the applicable increment(s). If a plan revision proposing less restrictive requirements was submitted after August 7, 1977 but on or before any applicable baseline date and was pending action by the Administrator on that date, no such demonstration is necessary with respect to the area for which a baseline date would be established before final action is taken on the plan revision. Instead, the assessment described in paragraph

(a)(4) shall review the expected impact to the applicable increment(s).

* * * * *

(6) *Amendments.* (i) Any state required to revise its implementation plan by reason of an amendment to this section, including any amendment adopted simultaneously with this paragraph, shall adopt and submit such plan revision to the Administrator for approval before May 7, 1981.

(ii) Any revision to an implementation plan that would amend the provisions for the prevention of significant air quality deterioration in the plan shall specify when and as to what sources and modifications the revision is to take effect.

(iii) Any revision to an implementation plan that an amendment to this section required shall take effect no later than the date of its approval and may operate prospectively.

(b) *Definitions.* All state plans shall use the following definitions for the purposes of this section. Deviations from the following wording will be approved only if the state specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects as the corresponding definitions below:

(1)(i) "Major stationary source" means:

(*a*) Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(*b*) Notwithstanding the stationary source size specified in paragraph (b)(1)(i)(*a*) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(*c*) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source if the change would constitute a major stationary source by itself.

(ii) A major source that is major for volatile organic compounds shall be considered major for ozone.

(2)(i) "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(*a*) Routine maintenance, repair, and replacement;

(*b*) Use of an alternative fuel or raw material by reason of any order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(*c*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(*d*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(*e*) Use of an alternative fuel or raw material by a stationary source which:

(*1*) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24; or

(*2*) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.24;

(*f*) An increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24.

(*g*) Any change in ownership at a stationary source.

(3)(i) "Net emissions increase" means the amount by which the sum of the following exceeds zero:

(*a*) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(*b*) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within a reasonable period (to be specified by the state) before the date that the increase from the particular change occurs.

(iii) An increase or decrease in actual emissions is creditable only if the reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs.

(iv) An increase or decrease in actual emissions of sulfur dioxide or particulate matter which occurs before the applicable baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

(v) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(vi) A decrease in actual emissions is creditable only to the extent that:

(*a*) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

(*b*) It is federally enforceable at and after the time that actual construction on the particular change begins; and

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(vii) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(4) "Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of

operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(5) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

(6) "Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(7) "Emissions unit" means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(8) "Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

(9) "Commence" as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(10) "Necessary preconstruction approvals or permits" means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(11) "Begin actual construction" means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operation this term refers to those on-site activities, other than preparatory activities, which mark the initiation of the change.

(12) "Best available control technology" means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the reviewing authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

(13)(i) "Baseline concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and shall include:

(*a*) The actual emissions representative of sources in existence on the applicable baseline date, except as provided in paragraph (b)(13)(ii);

(*b*) The allowable emissions of major stationary sources which commenced construction before January 6, 1975, but were not in operation by the applicable baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emission from any major stationary source on which construction commenced after January 6, 1975; and

(*b*) Actual emissions increases and decreases at any stationary source occurring after the baseline date.

(14)(i) "Baseline date" means the earliest date after August 7, 1977, that:

(*a*) A major stationary source or major modification subject to 40 CFR 52.21 submits a complete application under that section; or

(*b*) A major stationary source or major modificatioin subject to regulations approved pursuant to 40 CFR 51.24 submits a complete application under such regulations.

(ii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(*a*) The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i) (D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.24; and

(*b*) In the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(15)(i) "Baseline area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under section 107(d)(1) (D) or (E) of the Act in which the major source or major modification establishing the baseline date would construct or would have an air quality impact equal to or greater than 1 $\mu g/m^3$ (annual average) of the pollutant for which the baseline date is established.

(ii) Area redesignations under section 107(d)(1) (D) or (E) of the Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(*a*) Establishes a baseline date; or

(*b*) Is subject to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.24, and would be constructed in the same state as the state proposing the redesignation.

(16) "Allowable emissions" means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits

which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(i) The applicable standards as set forth in 40 CFR Parts 60 and 61;

(ii) The applicable State Implementation Plan emissions limitation, including those with a future compliance date; or

(iii) The emissions rate specified as a federally enforceable permit condition.

(17) "Federally enforceable" means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24.

(18) "Secondary emissions" means emissions which occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purposes of this section, secondary emissions must be specific, well defined, quantifiable, and impact the same general areas the stationary source modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

(i) Emissions from ships or trains coming to or from the new or modified stationary source; and

(ii) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

(19) "Innovative control technology" means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts.

(20) "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(21)(i) "Actual emissions" means the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with subparagraphs (ii)–(iv) below.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The reviewing authority may allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(22) "Complete" means, in reference to an application for a permit, that the application contains all the information necessary for processing the application. Designating an application complete for purposes of permit processing does not preclude the reviewing authority from requesting or accepting any additional information.

(23)(i) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy
Asbestos: 0.007 tpy
Beryllium: 0.0004 tpy
Mercury: 0.1 tpy
Vinyl chloride: 1 tpy
Fluorides: 3 tpy
Sulfuric acid mist: 7 tpy
Hydrogen sulfide (H_2S): 10 tpy
Total reduced sulfur (including H_2S): 10 tpy
Reduced sulfur compounds (including H_2S): 10 tpy

(ii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the Act that paragraph (b)(23)(i) does not list, any emissions rate.

(iii) Notwithstanding paragraph (b)(23)(i), "significant" means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 $\mu g/m^3$ (24-hour average).

(24) "Federal Land Manager" means, with respect to any lands in the United States, the Secretary of the department with authority over such lands.

(25) "High terrain" means any area having an elevation 900 feet or more above the base of the stack of a source.

(26) "Low terrain" means any area other than high terrain.

(27) "Indian Reservation" means any federally recognized reservation established by Treaty, Agreement, Executive Order, or Act of Congress.

(28) "Indian Governing Body" means the governing body of any tribe, band, or group of Indians subject to the jurisdiction of the United States and recognized by the United States as possessing power of self-government.

* * * * *

(f) *Exclusions from increment consumption.* (1) The plan may provide that the following concentrations shall be excluded in determining compliance with a maximum allowable increase:

(i) Concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(ii) Concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(iii) Concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(iv) The increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(v) Concentrations attributable to the temporary increase in emissions of sulfur dioxide or particulate matter from stationary sources which are affected by plan revisions approved by the Administrator as meeting the criteria specified in paragraph (f)(4).

(2) If the plan provides that the concentrations to which paragraph (f)(1)(i) or (ii) refers shall be excluded, it shall also provide that no exclusion of such concentrations shall apply more than five years after the effective date of the

order to which paragraph (f)(1)(i) refers or the plan to which paragraph (f)(1)(ii) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under paragraph (f) of this section shall occur later than 9 months after August 7, 1980, unless a State Implementation Plan revision meeting the requirements of 40 CFR 51.24 has been submitted to the Administrator.

(4) For purposes of excluding concentrations pursuant to paragraph (f)(1)(v), the Administrator may approve a plan revision that:

(i) Specifies the time over which the temporary emissions increase of sulfur dioxide or particulate matter would occur. Such time is not to exceed two years in duration unless a longer time is approved by the Administrator;

(ii) Specifies that the time period for excluding certain contributions in accordance with paragraph (f)(4)(i) is not renewable;

(iii) Allows no emissions increase from a stationary source which would:

(*a*) Impact a Class I area or an area where an applicable increment is known to be violated; or

(*b*) Cause or contribute to the violation of a national ambient air quality standard;

(iv) Requires limitations to be in effect the end of the time period specified in accordance with paragraph (f)(4)(i) which would ensure that the emissions levels from stationary sources affected by the plan revision would not exceed those levels occurring from such sources before the plan revision was approved.

* * * * *

(i) *Review of Major Stationary Sources and Major Modifications—Source Applicability and Exemptions.*

(1) The plan shall provide that no major stationary source or major modification shall begin actual construction unless, as a minimum, requirements equivalent to those contained in paragraphs (j) through (r) of this section have been met.

(2) The plan shall provide that the requirements equivalent to those contained in paragraphs (j) through (r) of this section shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the Act that it would emit, except as this section would otherwise allow.

(3) The plan shall provide that requirements equivalent to those contained in paragraphs (j) through (r) of this section apply only to any major stationary source or major modification that would be constructed in an area which is designated as attainment or unclassifiable under section 107(a)(1)(D) or (E) of the Act; and

(4) The plan may provide that requirements equivalent to those contained in paragraphs (j) through (r) of this section do not apply to a particular major stationary source or major modification if:

(i) The major stationary source would be a nonprofit health or nonprofit educational institution or a major modification that would occur at such an institution; or

(ii) The source or modification would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and such source does not belong to any following categories:

(*a*) Coal cleaning plants (with thermal dryers);

(*b*) Kraft pulp mills;

(*c*) Portland cement plants;

(*d*) Primary zinc smelters;

(*e*) Iron and steel mills;

(*f*) Primary aluminum ore reduction plants;

(*g*) Primary copper smelters;

(*h*) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(*i*) Hydrofluoric, sulfuric, or nitric acid plants;

(*j*) Petroleum refineries;

(*k*) Lime plants;

(*l*) Phosphate rock processing plants;

(*m*) Coke oven batteries;

(*n*) Sulfur recovery plants;

(*o*) Carbon black plants (furnace process);

(*p*) Primary lead smelters;

(*q*) Fuel conversion plants;

(*r*) Sintering plants;

(*s*) Secondary metal production plants;

(*t*) Chemical process plants;

(*u*) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(*v*) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(*w*) Taconite ore processing plants;

(*x*) Glass fiber processing plants;

(*y*) Charcoal production plants;

(*z*) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(*aa*) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act; or

(iii) The source or modification is a portable stationary source which has previously received a permit under requirements equivalent to those contained in paragraphs (j) through (r) of this section, if:

(*a*) The source proposes to relocate and emissions of the source at the new location would be temporary; and

(*b*) The emissions from the source would not exceed its allowable emissions; and

(*c*) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated; and

(*d*) Reasonable notice is given to the reviewing authority prior to the relocation identifying the proposed new location and the probable duration of operation at the new location. Such notice shall be given to the reviewing authority not less than 10 days in advance of the proposed relocation unless a different time duration is previously approved by the reviewing authority.

(5) The plan may provide that requirements equivalent to those contained in paragraphs (j) through (r) of this section do not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment under section 107 of the Act.

(6) The plan may provide that requirements equivalent to those contained in paragraphs (k), (m), and (o) of this section do not apply to a proposed major stationary source or major modification with respect to a particular pollutant, if the allowable emissions of that pollutant from a new source, or the net emissions increase of that pollutant from a modification, would be temporary and impact no Class I area and no area where an applicable increment is known to be violated.

(7) The plan may provide that requirements equivalent to those contained in paragraphs (k), (m), and (o) of this section as they relate to any maximum allowable increase for a Class II area do not apply to a modification of a major stationary source that was in existence on March 1, 1978, if the net increase in allowable emissions of each pollutant subject to regulation under the Act from the modification after the application of best available control technology would be less than 50 tons per year.

(8) The plan may provide that the reviewing authority may exempt a proposed major stationary source or major modification from the requirements of paragraph (m) with

respect to monitoring for a particular pollutant, if:

(i) The emissions increase of the pollutant from a new stationary source or the net emissions increase of the pollutant from a modification would cause, in any area, air quality impacts less than the following amounts:

(*a*) Carbon monoxide—575 ug/m³, 8-hour average;

(*b*) Nitrogen dioxide—14 ug/m³, annual average;

(*c*) Total suspended particulates—10 ug/m³, 24-hour average;

(*d*) Sulfur dioxide—13 ug/m³, 24-hour average;

(*e*) Ozone [1]

(*f*) Lead—0.1 ug/m³, 24-hour average;

(*g*) Mercury—0.25 ug/m³, 24-hour average;

(*h*) Beryllium—0.0005 ug/m³, 24-hour average;

(*i*) Fluorides—0.25 ug/m³, 24-hour average;

(*j*) Vinyl chloride—15 ug/m³, 24-hour average;

(*k*) Total reduced sulfur—10 ug/m³, 1-hour average;

(*l*) Hydrogen sulfide—0.04 ug/m³, 1-hour average;

(*m*) Reduced sulfur compounds—10 ug/m³, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in (i)(8)(i); or

(iii) The pollutants is not listed in paragraph (i)(8)(i).

(9) If EPA approves a plan revision under 40 CFR 51.24 as in effect before August 7, 1980, any subsequent revision which meets the requirements of this section may contain transition provisions which parallel the transition provisions of 40 CFR 52.21(i)(9), (i)(10) and (m)(1)(v) as in effect on that date, which provisions relate to requirements for best available control technology and air quality analyses. Any such subsequent revision may not contain any transition provision which in the context of the revision would operate any less stringently than would its counterpart in 40 CFR 52.21.

(j) *Control Technology Review.* The plan shall provide that:

(1) A major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emission standards and standard of performance under 40 CFR Parts 60 and 61.

(2) A new major stationary source shall apply best available control technology for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts.

(3) A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would be a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.

(4) For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the least reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

(k) *Source Impact Analysis.* The plan shall provide that the owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reduction (including secondary emissions) would not cause or contribute to air pollution in violation of:

(1) Any national ambient air quality standard in any air quality control region; or

(2) Any applicable maximum allowable increase over the baseline concentration in any area.

(l) *Air Quality Models.*

* * * * *

(m) *Air Quality Analysis.* (1) Preapplication analysis.

(i) The plan shall provide that any application for a permit under regulations approved pursuant to this section shall contain an analysis of ambient air quality in the area that the major stationary source or major modification would affect for each of the following pollutants:

(*a*) For the source, each pollutant that it would have the potential to emit in a significant amount;

(*b*) For the modification, each pollutant for which it would result in a significant net emissions increase.

(ii) The plan shall provide that, with respect to any such pollutant for which no National Ambient Air Quality Standard exists, the analysis shall contain such air quality monitoring data as the reviewing authority determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect.

(iii) The plan shall provide that with respect to any such pollutant (other than nonmethane hydrocarbons) for which such a standard does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase.

(iv) The plan shall provide that, in general, the continuous air monitoring data that is required shall have been gathered over a period of one year and shall represent the year preceding receipt of the application, except that, if the reviewing authority determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period.

(v) The plan may provide that the owner or operator of a proposed major stationary source or major modification of volatile organic compounds who satisfies all conditions of 40 CFR Part 51 Appendix S, section IV may provide postapproval monitoring data for ozone in lieu of providing preconstruction data as required under paragraph (m)(1).

(2) Post-construction monitoring. The plan shall provide that the owner or operator of a major stationary source or major modification shall, after construction of the stationary source or modification, conduct such ambient monitoring as the reviewing authority determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having, on air quality in any area.

(3) Operation of monitoring stations. The plan shall provide that the owner or operator of a major stationary source or major modification shall meet the requirements of Appendix B to Part 58 of this chapter during the operation of monitoring stations for purposes of satisfying paragraph (m) of this section.

(n) *Source Information.*

* * * * *

(o) *Additional Impact Analyses.*

* * * * *

(p) *Sources Impacting Federal Class I Areas—Additional Requirements.*

* * * * *

(q) *Public Participation.*

* * * * *

[1] No *de minimis* air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform and ambient impact analysis, including the gathering of ambient air quality data.

(r) *Source Obligation.* (1) The plan shall include enforceable procedures to provide that approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the plan and any other requirements under local, state or federal law.

(2) The plan shall provide that at such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of paragraphs (j) through (s) of this section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(s) *Innovative Control Technology.* (1) The plan may provide that an owner or operator of a proposed major stationary source or major modification may request the reviewing authority to approve a system of innovative control technology.

(2) The plan may provide that the reviewing authority may, with the consent of the governor(s) of other affected state(s), determine that the source or modification may employ a system of innovative control technology, if:

(i) The proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function;

(ii) The owner or operator agrees to achieve a level of continuous emissions reduction equivalent to that which would have been required under paragraph (j)(2) by a date specified by the reviewing authority. Such date shall not be later than 4 years from the time of startup or 7 years from permit issuance;

(iii) The source or modification would meet the requirements equivalent to those in paragraphs (j) and (k) based on the emissions rate that the stationary source employing the system of innovative control technology would be required to meet on the date specified by the reviewing authority;

(iv) The source or modification would not before the date specified by the reviewing authority:

(*a*) Cause or contribute to any violation of an applicable national ambient air quality standard; or

(*b*) Impact any Class I area; or

(*c*) Impact any area where an applicable increment is known to be violated;

(v) All other applicable requirements including those for public participation have been met.

(3) The plan shall provide that the reviewing authority shall withdraw any approval to employ a system of innovative control technology made under this section, if:

(i) The proposed system fails by the specified date to achieve the required continuous emissions reduction rate; or

(ii) The proposed system fails before the specified date so as to contribute to an unreasonable risk to public health, welfare, or safety; or

(iii) The reviewing authority decides at any time that the proposed system is unlikely to achieve the required level of control or to protect the public health, welfare, or safety.

(4) The plan may provide that if a source or modification fails to meet the required level of continuous emissions reduction within the specified time period, or if the approval is withdrawn in accordance with paragraph (s)(3), the reviewing authority may allow the source or modification up to an additional 3 years to meet the requirement for the application of best available control technology through use of a demonstrated system of control.

New Source Review For PSD Purposes

2. (a) Section 52.21 of Title 40 of the Code of Federal Regulations is amended by deleting paragraph (k) and redesignating paragraphs (l) through (v) as (k) through (u) and then by revising paragraphs (b), (f), (i), (j), (k) and (g) and adding new paragraphs (r)(4), (v) and (w) as follows:

§ 52.21. Prevention of significant deterioration of air quality.

* * * * *

(b) *Definitions.* For the purposes of this section:

(1)(i) "Major stationary source" means:

(*a*) Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(*b*) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(*c*) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source, if the changes would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone.

(2)(i) "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(*a*) Routine maintenance, repair and replacement;

(*b*) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plant pursuant to the Federal Power Act;

(*c*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(*d*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(*e*) Use of an alternative fuel or raw material by a stationary source which:

(*1*) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 CFR 52.21

or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24; or

(2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.24;

(f) An increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24.

(g) Any change in ownership at a stationary source.

(3)(i) "Net emissions increase" means the amount by which the sum of the following exceeds zero:

(a) Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and

(b) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:

(*a*) The date five years before construction on the particular change commences; and

(*b*) The date that the increase from the particular change occurs.

(iii) An increase or decrease in actual emissions is creditable only if the Administrator has not relied on it in issuing a permit for the source under this section, which permit is in effect when the increase in actual emissions from the particular change occurs.

(iv) An increase or decrease in actual emissions of sulfur dioxide or particulate matter which occurs before the applicable baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

(v) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(vi) A decrease in actual emissions is creditable only to the extent that:

(*a*) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

(*b*) It is federally enforceable at and after the time that actual construction on the particular change begins; and

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(viii) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(4) "Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(5) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

(6) "Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U. S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

(7) "Emissions unit" means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(8) "Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

(9) "Commence" as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(10) "Necessary preconstruction approvals or permits" means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(11) "Begin actual contruction" means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying underground pipework and construction of permanent storage structures. With respect to a change in method of operations, this term refers to those on-site activites other than preparatory activities which mark the initiation of the change.

(12) "Best available control technology" means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts and 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such

design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

(13)(i) "Baseline concentration" means that ambient concentration level which exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and shall include:

(*a*) The actual emissions representative of sources in existence on the applicable baseline date, except as provided in paragraph (b)(13)(ii);

(*b*) The allowable emissions of major stationary sources which commenced construction before January 6, 1975, but were not in operation by the applicable baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emissions from any major stationary source on which construction commenced after January 6, 1975; and

(*b*) Actual emissions increases and decreases at any stationary source occurring after the baseline date.

(14)(i) "Baseline date" means the earliest date after August 7, 1977, on which the first complete application under 40 CFR 52.21 is submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21.

(ii) The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

(*a*) The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under section 107(d)(i) (D) or (E) of the Act for the pollutant on the date of its complete application under 40 CFR 52.21; and

(*b*) In the case of a major stationary source, the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

(15)(i) "Baseline area" means any intrastate area (and every part thereof) designated as attainment or unclassifiable under section 107(d)(1) (D) or (E) of the Act in which the major source or major modification establishing the baseline date would construct or would have an air quality impact equal to or greater than 1 $\mu g/m^3$ (annual average) of the pollutant for which the baseline date is established.

(ii) Area redesignations under section 107(d)(1) (D) or (E) of the Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification which:

(*a*) Establishes a baseline date; or

(*b*) Is subject to 40 CFR 52.21 and would be constructed in the same state as the state proposing the redesignation.

(16) "Allowable emissions" means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(i) The applicable standards as set forth in 40 CFR Parts 60 and 61;

(ii) The applicable State Implemenation Plan emissions limitation, including those with a future compliance date; or

(iii) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(17) "Federally enforceable" means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 and 40 CFR 51.24.

(18) "Secondary emissions" means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this section, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

(i) Emissions from ships or trains coming to or from the new or modified stationary source; and

(ii) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

(19) "Innovative control technology" means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts.

(20) "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(21)(i) "Actual emissions" means the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with subparagraphs (ii)–(iv) below.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedies the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(22) "Complete" means, in reference to an application for a permit, that the application contains all of the information necessary for processing the application.

(23)(i) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy
Asbestos: 0.007 tpy
Beryllium: 0.0004 tpy
Mercury: 0.1 tpy
Vinyl chloride: 1 tpy
Fluorides: 3 tpy
Sulfuric acid mist: 7 tpy
Hydrogen sulfide (H_2S): 10 tpy
Total reduced sulfur (including H_2S): 10 tpy
Reduced sulfur compounds (including H_2S): 10 tpy

(ii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the Act that paragraph (b)(23)(i) does not list, any emissions rate.

(iii) Notwithstanding paragraph (b)(23)(i), "significant" means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 $\mu g/m^3$, (24-hour average).

(24) "Federal Land Manager" means, with respect to any lands in the United States, the Secretary of the department with authority over such lands.

(25) "High terrain" means any area having an elevation 900 feet or more above the base of the stack of a source.

(26) "Low terrain" means any area other than high terrain.

(27) "Indian Reservation" means any federally recognized reservation established by Treaty, Agreement, Executive Order, or Act of Congress.

(28) "Indian Governing Body" means the governing body of any tribe, band, or group of Indians subject to the jurisdiction of the United States and recognized by the United States as possessing power of selfgovernment.

* * * * *

(f) *Exclusions from increment consumption.* (1) Upon written request of the governor, made after notice and opportunity for at least one public hearing to be held in accordance with procedures established in 40 CFR 51.4, the Administrator shall exclude the following concentrations in determining compliance with a maximum allowable increase:

(i) Concentrations attributable to the increase in emissions from stationary sources which have converted from the use of petroleum products, natural gas, or both by reason of an order in effect under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) over the emissions from such sources before the effective date of such an order;

(ii) Concentrations attributable to the increase in emissions from sources which have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act over the emissions from such sources before the effective date of such plan;

(iii) Concentrations of particulate matter attributable to the increase in emissions from construction or other temporary emission-related activities of new or modified sources;

(iv) The increase in concentrations attributable to new sources outside the United States over the concentrations attributable to existing sources which are included in the baseline concentration; and

(v) Concentrations attributable to the temporary increase in emissions of sulfur dioxide or particulate matter from stationary sources which are affected by plan revisions approved by the Administrator as meeting the criteria specified in paragraph (f)(4).

(2) No exclusion of such concentrations shall apply more than five years after the effective date of the order to which paragraph (f)(1)(i) refers or the plan to which paragraph (f)(1)(ii) refers, whichever is applicable. If both such order and plan are applicable, no such exclusion shall apply more than five years after the later of such effective dates.

(3) No exclusion under paragraph (f) of this section shall occur later than 9 months after August 7, 1980, unless a State Implementation Plan revision meeting the requirements of 40 CFR 51.24 has been submitted to the Administrator.

(4) For purposes of excluding concentrations pursuant to paragraph (f)(1)(v), the proposed plan revision shall:

(i) Specify the time over which the temporary emissions increase of sulfur dioxide or particulate matter would occur. Such time is not to exceed two years in duration unless a longer time is approved by the Administrator;

(ii) Specify that the time period for excluding certain contributions in accordance with paragraph (f)(4)(i) is not renewable;

(iii) Allow no emissions increase from a stationary source which would:

(*a*) Impact a Class I area or an area where an applicable increment is known to be violated; or

(*b*) Cause or contribute to the violation of a national ambient air quality standard;

(iv) Require limitations to be in effect at the end of the time period specified in accordance with paragraph (f)(4)(i) which would ensure that the emissions levels from stationary sources affected by the plan revision would not exceed those levels occurring from such sources before the plan revision was approved.

* * * * *

(i) *Review of Major Stationary Sources and Major Modifications—Source Applicability and Exemptions.* (1) No stationary source or modification to which the requirements of paragraphs (j) through (r) of this section apply shall begin actual construction without a permit which states that the stationary source or modification would meet those requirements. The Administrator has authority to issue any such permit.

(2) The requirements of paragraphs (j) through (r) of this section shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the Act that it would emit, except as this section otherwise provides.

(3) The requirements of paragraphs (j) through (r) of this section apply only to any major stationary source or major modification that would be constructed in an area designated as attainment or unclassifiable under section 107(d)(1)(D) or (E) of the Act.

(4) The requirements of paragraphs (j) through (r) of this section shall not apply to a particular major stationary source or major modification, if:

(i) Construction commenced on the source or modification before August 7, 1977. The regulations at 40 CFR 52.21 as in effect before August 7, 1977, shall govern the review and permitting of any such source or modification; or

(ii) The source or modification was subject to the review requirements of 40 CFR 52.21(d)(i) as in effect before March 1, 1978, and the owner or operator:

(a) Obtained under 40 CFR 52.21 a final approval effective before March 1, 1978;

(b) Commenced construction before March 19, 1979; and

(c) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time; or

(iii) The source or modification was subject to 40 CFR 52.21 as in effect before March 1, 1978, and the review of an application for approval for the stationary source or modification under 40 CFR 52.21 would have been completed by March 1, 1978, but for an extension of the public comment period pursuant to a request for such an extension. In such a case, the application shall continue to be processed, and granted or denied, under 40 CFR 52.21 as in effect prior to March 1, 1978; or

(iv) The source or modification was not subject to 40 CFR 52.21 as in effect before March 1, 1978, and the owner or operator:

(a) Obtained all final federal, state and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before March 1, 1978;

(b) Commenced construction before March 19, 1979; and

(c) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time; or

(v) The source or modification was not subject to 40 CFR 52.21 as in effect on June 19, 1978 or under the partial stay

of regulations published on February 5, 1980 (45 FR 7800), and the owner or operator:

(a) Obtained all final federal, state and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before August 7, 1980;

(b) Commenced construction within 18 months from August 7, 1980, or any earlier time required under the applicable State Implementation Plan; and

(c) Did not discontinuue construction for a period of 18 months or more and completed construction within a reasonable time; or

(vi) The source or modification would be a nonprofit health or nonprofit educational institution, or a major modification would occur at such an institution, and the governor of the state in which the source or modification would be located requests that it be exempt from those requirements; or

(vii) The source or modification would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(a) Coal cleaning plants (with thermal dryers);

(b) Kraft pulp mills;

(c) Portland cement plants;

(d) Primary zinc smelters;

(e) Iron and steel mills;

(f) Primary aluminum ore reduction plants;

(g) Primary copper smelters;

(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(i) Hydrofluoric, sulfuric, or nitric acid plants;

(j) Petroleum refineries;

(k) Lime plants;

(l) Phosphate rock processing plants;

(m) Coke oven batteries;

(n) Sulfur recovery plants;

(o) Carbon black plants (furnace process);

(p) Primary lead smelters;

(q) Fuel conversion plants;

(r) Sintering plants;

(s) Secondary metal production plants;

(t) Chemical process plants;

(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(w) Taconite ore processing plants;

(x) Glass fiber processing plants;

(y) Charcoal production plants;

(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act; or

(viii) The source is a portable stationary source which has previously received a permit under this section, and

(*a*) The owner or operator proposes to relocate the source and emissions of the source at the new location would be temporary; and

(*b*) The emissions from the source would not exceed its allowable emissions; and

(*c*) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated; and

(*d*) Reasonable notice is given to the Administrator prior to the relocation identifying the proposed new location and the probable duration of operation at the new location. Such notice shall be given to the Administrator not less than 10 days in advance of the proposed relocation unless a different time duration is previously approved by the Administrator.

(5) The requirements of paragraphs (j) through (r) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment under section 107 of the Act.

(6) The requirements of paragraphs (k), (m) and (o) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant, if the allowable emissions of that pollutant from the source, or the net emissions increase of that pollutant from the modification:

(i) Would impact no Class I area and no area where an applicable increment is known to be violated, and

(ii) Would be temporary.

(7) The requirements of paragraphs (k), (m) and (o) of this section as they relate to any maximum allowable increase for a Class II area shall not apply to a major modification at a stationary source that was in existence on March 1, 1978, if the net increase in allowable emissions of each pollutant subject to regulation under the Act from the modification after the application of best available control technology would be less than 50 tons per year.

(8) The Administrator may exempt a stationary source or modification from the requirements of paragraph (m) with respect to monitoring for a particular pollutant if:

(i) The emissions increase of the pollutant from the new source or the net emissions increase of the pollutant from the modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide—575 $\mu g/m^3$, 8-hour average;

Nitrogen dioxide—14 $\mu g/m^3$, annual average;

Total suspended particulate—10 $\mu g/m^3$, 24-hour average;

Sulfur dioxide—13 $\mu g/m^3$, 24-hour average;

Ozone; [2]

Lead—0.1 $\mu g/m^3$, 24-hour average;

Mercury—0.25 $\mu g/m^3$, 24-hour average;

Beryllium—0.0005 $\mu g/m^3$, 24-hour average;

Fluorides—0.25 $\mu g/m^3$, 24-hour average;

Vinyl chloride—15 $\mu g/m^3$, 24-hour average;

Total reduced sulfur—10 $\mu g/m^3$, 1-hour average;

Hydrogen sulfide—0.04 $\mu g/m^3$, 1-hour average;

Reduced sulfur compounds—10 $\mu g/m^3$, 1-hour average; or

(ii) The concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in paragraph (i)(8)(i), or the pollutant is not listed in paragraph (i)(8)(i).

(9) The requirements for best available control technology in paragraph (j) of this section and the requirements for air quality analyses in paragraph (m)(1) shall not apply to a particular stationary source or modification that was subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submitted an application for a permit under those regulations before August 7, 1980, and the Administrator subsequently determines that the application as submitted before that date was complete. Instead, the requirements at 40 CFR 52.21(j) and (n) as in effect on June 19, 1978 apply to any such source or modification.

(10)(i) The requirements for air quality monitoring in paragraphs (m)(1)(ii)-(iv) of this section shall not apply to a particular source or modification that was subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submits an

[2] No *de minimis* air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data.

application for a permit under this section on or before June 8, 1981, and the Administrator subsequently determines that the application as submitted before that date was complete with respect to the requirements of this section other than those in paragraphs (m)(1)(ii)-(iv) and with respect to the requirements for such analyses at 40 CFR 52.21(m)(2) as in effect on June 19, 1978. Instead, the latter requirements shall apply to any such source or modification.

(ii) The requirements for air quality monitoring in paragraphs (m)(1)(ii)-(iv) of this section shall not apply to a particular source or modification that was not subject to 40 CFR 52.21 as in effect on June 19, 1978, if the owner or operator of the source or modification submits an application for a permit under this section on or before June 8, 1981, and the Administrator subsequently determines that the application as submitted before that date was complete, except with respect to the requirements in paragraphs (m)(1)(ii)-(iv).

(j) *Control Technology Review.* (1) A major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60 and 61.

(2) A new major stationary source shall apply best available control technology for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts.

(3) A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.

(4) For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

(k) *Source Impact Analysis.* The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:

(1) Any national ambient air quality standard in any air quality control region; or

(2) Any applicable maximum allowable increase over the baseline concentration in any area.

(l) *Air Quality Models.*

* * * * *

(m) *Air Quality Analysis.* (1) Preapplication analysis.

(i) Any application for a permit under this section shall contain an analysis of ambient air quality in the area that the major stationary source or major modification would affect for each of the following pollutants:

(*a*) For the source, each pollutant that it would have the potential to omit in a significant amount;

(*b*) For the modification, each pollutant for which it would result in a significant net emissions increase.

(ii) With respect to any such pollutant for which no National Ambient Air Quality Standard exists, the analysis shall contain such air quality monitoring data as the Administrator determines is necessary to assess ambient air quality for that pollutant in any area that the emissions of that pollutant would affect.

(iii) With respect to any such pollutant (other than nonmethane hydrocarbons) for which such a standard does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the standard or any maximum allowable increase.

(iv) In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the application, except that, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period.

(v) For any application which becomes complete, except as to the requirements of paragraph (m)(1) (iii) and (iv), between June 8, 1981, and February 9, 1982, the data that paragraph (m)(1)(iii) requires shall have been gathered over at least the period from February 9, 1981, to the date the application becomes otherwise complete, except that:

(*a*) If the source or modification would have been major for that pollutant under 40 CFR 52.21 as in effect on June 19, 1978, any monitoring data shall have been gathered over at least the period required by those regulations.

(*b*) If the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data over a shorter period (not to be less than four months), the data that paragraph (m)(1)(iii) requires shall have been gathered over at least that shorter period.

(*c*) If the monitoring data would relate exclusively to ozone and would not have been required under 40 CFR 52.21 as in effect on June 19, 1978, the Administrator may waive the otherwise applicable requirements of this paragraph (v) to the extent that the applicant shows that the monitoring data would be unrepresentative of air quality over a full year.

(vi) The owner or operator of a proposed stationary source or modification of violatile organic compounds who satisfies all conditions of 40 CFR Part 51 Appendix S, section IV may provide post-approval monitoring data for ozone in lieu of providing preconstruction data as requried under paragraph (m)(1).

(2) Post-construction monitoring. The owner or operator of a major stationary source or major modification shall, after construction of the stationary source or modification, conduct such ambient monitoring as the Administrator determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having, on air quality in any area.

(3) Operations of monitoring stations. The owner or operator of a major stationary source or major modification shall meet the requirements of Appendix B to Part 58 of this chapter during the operation of monitoring stations for purposes of satisfying paragraph (m) of this section.

(n) *Source Information.*

* * * * *

(o) *Additional Impact Analyses.*

* * * * *

(p) *Sources Impacting Federal Class I Areas—Additional Requirements.*

* * * * *

(q) *Public Participation.* The Administrator shall follow the applicable procedures of 40 CFR Part 124 in processing applications under this section. The Administrator shall follow the procedures at 40 CFR 52.21(r) as in effect on June 19, 1979, to the extent that

the procedures of 40 CFR Part 124 do not apply.

(r) *Source Obligation.*

* * * * *

(4) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements or paragraphs (j) through (s) of this section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

* * * * *

(s) *Environmental Impact Statements.*

* * * * *

(t) *Disputed Permits or Redesignations.*

* * * * *

(u) *Delegation of Authority.*

* * * * *

(v) *Innovative Control Technology.* (1) An owner or operator of a proposed major stationary source or major modification may request the Administrator in writing no later than the close of the comment period under 40 CFR 124.10 to approve a system of innovative control technology.

(2) The Administrator shall, with the consent of the governor(s) of the affected state(s), determine that the source or modification may employ a system of innovative control technology, if:

(i) The proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function;

(ii) The owner or operator agrees to achieve a level of continuous emissions reduction equivalent to that which would have been required under paragraph (j)(2) by a date specified by the Administrator. Such date shall not be later than 4 years from the time of startup or 7 years from permit issuance;

(iii) The source or modification would meet the requirements of paragraphs (j) and (k) based on the emissions rate that the stationary source employing the system of innovative control technology would be required to meet on the date specified by the Administrator;

(iv) The source or modification would not before the date specified by the Administrator:

(a) Cause or contribute to a violation of an applicable national ambient air quality standard; or

(b) Impact any Class I area; or

(c) Impact any area where an applicable increment is known to be violated; and

(v) All other applicable requirements including those for public participation have been met.

(3) The Administrator shall withdraw any approval to employ a system of innovative control technology made under this section, if:

(i) The proposed system fails by the specified date to achieve the required continuous emissions reduction rate; or

(ii) The proposed system fails before the specified date so as to contribute to an unreasonable risk to public health, welfare, or safety; or

(iii) The Administrator decides at any time that the proposed system is unlikely to achieve the required level of control or to protect the public health, welfare, or safety.

(4) If a source or modification fails to meet the required level of continuous emission reduction within the specified time period or the approval is withdrawn in accordance with paragraph (v)(3), the Administrator may allow the source or modification up to an additional 3 years to meet the requirement for the application of best available control technology through use of a demonstrated system of control.

(w) *Permit rescission.* (1) Any permit issued under this section or a prior version of this section shall remain in effect, unless and until it expires under paragraph (s) of this section or is rescinded.

(2) Any owner or operator of a stationary source or modification who holds a permit for the source or modification which was issued under 40 CFR 52.21 as in effect on June 19, 1978, may request that the Administrator rescind the permit or a particular portion of the permit.

(3) The Administrator shall grant an application for rescission if the application shows that this section would not apply to the source or modification.

(4) If the Administrator rescinds a permit under this paragraph, the public shall be given adequate notice of the rescission. Publication of an announcement of rescission in a newspaper of general circulation in the affected region within 60 days of the rescission shall be considered adequate notice.

2. (b) In § 52.60 (AL), § 52.96 (AK), § 52.144 (AZ), § 52.131 (AR), § 52.270 (CA), § 52.343 (CO), § 52.383 (CT), § 52.432 (DE), § 52.499 (DC), § 52.530 (FL), § 52.632 (HI), § 52.683 (ID), § 52.738 (IL), § 52.793 (IN), § 52.833 (IA), § 52.884 (KS), § 52.931 (KY), § 52.986 (LA), § 52.1116 (MD), § 52.1180 (MI), § 52.1234 (MN), § 52.1280 (MS), § 52.1339 (MO), § 52.1382 (MT), § 52.1436 (NB), § 52.1485 (NV), § 52.1529 (NH), § 52.1603 (NJ), § 52.1634 (NM), § 52.1689 (NY), § 52.1778 (NC), § 52.1884 (OH), § 52.1929 (OK), § 52.1987 (OR), § 52.2058 (PA), § 52.2083 (RI), § 52.2131 (SC), § 52.2178 (SD), § 52.2303 (TX), § 52.2346 (UT), § 52.2451 (VA), § 52.2497 (WA), § 52.2528 (WV), § 52.2581 (WI), § 52.2676 (GU), § 52.2729 (PR), § 52.2779 (VI), and § 52.2827 (AmS), paragraphs (a) and (b) are revised to read as follows:

* * * * *

(a) The requirements of sections 160 through 165 of the Clean Air Act are not met, since the plan does not include approvable procedures for preventing the significant deterioration of air quality.

(b) *Regulations for preventing significant deterioration of air quality.* The provisions of 52.21(b) through (w) are hereby incorporated and made a part of the applicable state plan for the State of ———.

Emission Offset Interpretative Ruling

3. Sections I, II, III and IV of the Emission Offset Interpretative Ruling, 40 CFR Part 51 Appendix S, as revised 44 FR 3274 (January 16, 1979) and 45 FR 31307 (May 13, 1980), are amended as follows:

A. By adding a new third paragraph to Section I, to read as follows:

I. Introduction

* * * * *

The requirement of this Ruling shall not apply to any major stationary source or major modification that was not subject to the Ruling as in effect on January 16, 1979, if the owner or operator:

A. Obtained all final federal, state, and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before August 7, 1980;

B. Commenced construction within 18 months from August 7, 1980, or any earlier time required under the applicable State Implementation Plan; and

C. Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time.

B. By revising Section II, subsection A, to read as follows:

II. Initial Screening Analyses and Determination of Applicable Requirements.

A. *Definitions*—For the purposes of this Ruling:

1. "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

2. "Building, structure, or facility" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control

of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same two digit code) as described in the *Standard Industrial Classification Manual*, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

3. "Installation" means an identifiable piece of process equipment.

4. "Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

5.(i) "Major stationary source" means:

(*a*) Any stationary source of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act; or

(*b*) Any physical change that would occur at a stationary source not qualifying under paragraph 5.(i)(*a*) as a major stationary source, if the change would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone.

6.(i) "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is considered significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(*a*) Routine maintenance, repair, and replacement;

(*b*) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(*c*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(*d*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(*e*) Use of an alternative fuel or raw material by a stationary source which:

(*1*) The source was capable of accommodating before December 21, 1976, unless such change would be prohibited under any federally enforceable permit condition which was established after December 21, 1976, purusant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24; or

(*2*) The source is approved to use under any permit issued under this ruling;

(*f*) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24;

(*g*) Any change in ownership at a stationary source.

7.(i) "Net emissions increase" means the amount by which the sum of the following exceeds zero:

(*a*) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(*b*) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:

(*a*) The date five years before construction on the particular change commences and

(*b*) The date that the increase from the particular change occurs.

(iii) An increase or decrease in actual emissions is creditable only if the Administrator has not relied on it in issuing a permit for the source under this Ruling which permit is in effect when the increase in actual emissions from the particular change occurs.

(iv) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(v) A decrease in actual emissions is creditable only to the extent that:

(*a*) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

(*b*) It is federally enforceable at and after the time that actual construction on the particular change begins;

(*c*) The reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR 51.18; and

(*d*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(vi) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

8. "Emissions unit" means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

9. "Reconstruction" will be presumed to have taken place where the fixed capital cost of the new components exceeds 50 per cent of the fixed capital cost of a comparable entirely new stationary source. Any final decision as to whether reconstruction has occurred shall be made in accordance with the provisions of 40 CFR 60.15(f) (1)–(3). A reconstructed stationary source will be treated as a new stationary source for purposes of this Ruling. In determining lowest achievable emission rate for a reconstructed stationary source, the provisions of 40 CFR 60.15(f)(4) shall be taken into account in assessing whether a new source performance standard is applicable to such stationary source.

10. "Fixed capital cost" means the capital needed to provide all the depreciable components.

11. "Secondary emissions" means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this Ruling, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

(i) Emissions from ships or trains coming to or from the new or modified stationary source and

(ii) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

12. "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

13.(i) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy

14. "Allowable emissions" means the emissions rate calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(i) Applicable standards as set forth in 40 CFR Parts 60 and 61;

(ii) Any applicable State Implementation Plan emissions limitation, including those with a future compliance date; or

(iii) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

15. "Federally enforceable" means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to this Ruling, 40 CFR 52.21, or under regulations approved pursuant to 40 CFR 51.18 or 51.24.

16.(i) "Actual emissions" means the actual rate of emissions of a pollutant from an

emissions unit as determined in accordance with subparagraphs (ii)–(iv) below.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored or combusted during the selected time period.

(iii) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

17. "Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

18. "Commence" as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

19. "Necessary preconstruction approvals or permits" means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

20. "Begin actual construction" means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operating this term refers to those on-site activities other than preparatory activities which mark the initiation of the change.

21. "Lowest achievable emission rate" means, for any source, the more stringent rate of emissions based on the following:

(i) The most stringent emissions limitation which is contained in the implementation plan of any state for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

(ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance.

22. "Resource recovery facility" means any facility at which solid waste is processed for the purpose of extracting, converting to energy, or otherwise separating and preparing solid waste for reuse. Energy conversion facilities must utilize solid waste to provide more than 50 percent of the heat input to be considered a resource recovery facility under this Ruling.

C. By amending Section II, subsection C by deleting footnote 2 and the second paragraph. The first paragraph is revised to read as follows:

C. Review of specified sources for air quality impact.

In addition, the reviewing authority must determine whether the major stationary source or major modification would be constructed in an area designated in 40 CFR 81.300 *et seq.* as nonattainment for a pollutant for which the stationary source or modification is major.

D. By revising Section II, subsection F to read as follows:

F. Fugitive emissions sources. Section IV. A. of this Ruling shall not apply to a source or modification that would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(1) Coal cleaning plants (with thermal dryers);
(2) Kraft pulp mills;
(3) Portland cement plants;
(4) Primary zinc smelters;
(5) Iron and steel mills;
(6) Primary aluminum ore reduction plants;
(7) Primary copper smelters;
(8) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(9) Hydrofluoric, sulfuric, or nitric acid plants;
(10) Petroleum refineries;
(11) Lime plants;
(12) Phosphate rock processing plants;
(13) Coke oven batteries;
(14) Sulfur recovery plants;
(15) Carbon black plants (furnace process);
(16) Primary lead smelters;
(17) Fuel conversion plants;
(18) Sintering plants;
(19) Secondary metal production plants;
(20) Chemical process plants;
(21) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(22) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(23) Taconite ore processing plants;
(24) Glass fiber processing plants;
(25) Charcoal production plants;
(26) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(27) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

E. By deleting Footnote 3 of subsection C of Section III and revising the third paragraph as follows:

C. Review of specified sources of air quality impact.

* * * * *

For ozone, sources of volatile organic compounds, locating outside a designated ozone nonattainment area, will be presumed to have no significant impact on the designated nonattainment area. If ambient monitoring indicates that the area of source location is in fact nonattainment, then the source may be permitted under the provisions of any state plan adopted pursuant to section 110(a)(2)(D) of the Act until the area is designated nonattainment and a State Implementation Plan revision is approved. If no state plan pursuant to section 110(a)(2)(D) has been adopted and approved, then this Ruling shall apply.

* * * * *

F. By adding a new subsection F. to IV., to read as follows:

IV. Sources That Would Locate in a Designated Nonattainment Area

F. Source Obligation.

At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of this Ruling shall apply to the source or modification as though construction had not yet commenced on the source or modification.

State Plans For New Source Review For Nonattainment Purposes.

4. Section 40 CFR 51.18(j) is amended to read as follows:

§ 51.18 Review of new stationary sources modifications.

* * * * *

(j) State Implementation Plan provisions satisfying sections 172(b)(6) and 173 of the Act shall meet the following conditions:

(1) All such plans shall use the specific definitions. Deviations from the following wording will be approved only if the state specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects as the corresponding definition below:

(i) "Stationary source" means any building, structure, facility, or installation which emits or may emit

any air pollutant subject to regulation under the Act.

(ii) "Building, structure, or facility" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same two-digit code) as described in the *Standard Industrial Classification Manual*, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

(iii) "Installation" means an identifiable piece of process equipment.

(iv) "Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(v)(*a*) "Major stationary source" means:

(*1*) Any stationary source of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act; or

(*2*) Any physical change that would occur at a stationary source not qualifying under paragraph (v)(*a*)(*1*) as a major stationary source, if the change would constitute a major stationary source by itself.

(*b*) A major stationary source that is major for volatile organic compounds shall be considered major for ozone.

(vi)(*a*) "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(*b*) Any net emissions increase that is considered significant for volatile organic compounds shall be considered significant for ozone.

(*c*) A physical change or change in the method of operation shall not include:

(*1*) Routine maintenance, repair and replacement;

(*2*) Use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(*3*) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(*4*) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(*5*) Use of an alternative fuel or raw material by a stationary source which:

(*i*) The source was capable of accommodating before December 21, 1976, unless such change would be prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24; or

(*ii*) The source is approved to use under any permit issued under regulations approved pursuant to this section;

(*6*) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24.

(*7*) Any change in ownership at a stationary source.

(vii)(*a*) "Net emissions increase" means the amount by which the sum of the following exceeds zero:

(*1*) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(*2*) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(*b*) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs before the date that the increase from the particular change occurs.

(*c*) An increase or decrease in actual emissions is creditable only if:

(*1*) It occurs within a reasonable period to be specified by the reviewing authority; and

(*2*) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section which permit is in effect when the increase in actual emissions from the particular change occurs.

(*d*) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(*e*) A decrease in actual emissions is creditable only to the extent that:

(*1*) The old level of actual emissions or the old level of allowable emissions, whichever, is lower, exceeds the new level of actual emissions;

(*2*) It is federally enforceable at and after the time that actual construction on the particular change begins; and

(*3*) The reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR 51.18 or the state has not relied on it in demonstrating attainment or reasonable further progress.

(*4*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(*f*) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(viii) "Emissions unit" means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(ix) "Reconstruction" will be presumed to have taken place where the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable entirely new stationary source. Any final decision as to whether reconstruction has occurred shall be made in accordance with the provisions of 40 CFR 60.15(f) (1)-(3). A reconstructed stationary source will be treated as a new stationary source for purposes of this subsection. In determining lowest achievable emission rate for a reconstructed stationary source, the provisions of 40 CFR 60.15(f)(4) shall be taken into account in assessing whether a new source performance standard is applicable to such stationary source.

(x) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(xi) "Secondary emissions" means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this section, secondary emissions must

be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

(*a*) Emissions from ships or trains coming to or from the new or modified stationary source; and

(*b*) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

(xii) "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(xiii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy

(xiv) "Allowable emissions" means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(*a*) The applicable standards set forth in 40 CFR Parts 60 or 61;

(*b*) Any applicable State Implementation Plan emissions limitation including those with a future compliance date; or

(*c*) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(xv)(*a*) "Actual emissions" means the actual rate of emissions of a pollutant from an emissions unit as determined in accordance with subparagraphs (*b*)–(*d*) below.

(*b*) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(*c*) The reviewing authority may presume that the source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(*d*) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(xvi) "Lowest achievable emission rate" means, for any source, the more stringent rate of emissions based on the following:

(*a*) The most stringent emissions limitation which is contained in the implementation plan of any state for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

(*b*) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.

(xvii) "Federally enforceable" means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to this section, 40 CFR 51.18, or 51.24.

(xviii) "Begin actual construction" means in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operating this term refers to those on-site activities other than preparatory activities which mark the initiation of the change.

(xix) "Commence" as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(*a*) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(*b*) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(xx) "Necessary preconstruction approvals or permits" means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(xxi) "Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

(2) Each plan shall adopt a preconstruction review program to satisfy the requirements of sections 172(b)(6) and 173 of the Act for any area designated nonattainment for any national ambient air quality standard under 40 CFR 81.300 *et seq.* Such a program shall apply to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(3)(i) Each plan shall provide that for sources and modifications subject to any preconstruction review program adopted pursuant to this subsection the baseline for determining credit for emissions reductions is the emissions limit under the applicable State Implementation Plan in effect at the time the application to construct is filed, except that the offset baseline shall be the actual emissions of the source from which offset credit is obtained where:

(*a*) The demonstration of reasonable further progress and attainment of ambient air quality standards is based upon the actual emissions of sources located within a designated nonattainment area for which the preconstruction review program was adopted; or

(*b*) The applicable State Implementation Plan does not contain an emissions limitation for that source or source category.

(ii) The plan shall further provide that:

(*a*) Where the emissions limit under the applicable State Implementation

Plan allows greater emissions than the potential to emit of the source, emissions offset credit will be allowed only for control below this potential;

(b) For an existing fuel combustion source, credit shall be based on the allowable emissions under the applicable State Implementation Plan for the type of fuel being burned at the time the application to construct is filed. If the existing source commits to switch to a cleaner fuel at some future date, emissions offset credit based on the allowable (or actual) emissions for the fuels involved is not acceptable, unless the permit is conditioned to require the use of a specified alternative control measure which would achieve the same degree of emissions reduction should the source switch back to a dirtier fuel at some later date. The reviewing authority should ensure that adequate long-term supplies of the new fuel are available before granting emissions offset credit for fuel switches;

(c) Emissions reductions achieved by shutting down an existing source or permanently curtailing production or operating hours below baseline levels may be credited, provided that the work force to be affected has been notified of the proposed shutdown or curtailment. Source shutdowns and curtailments in production or operating hours occurring prior to the date the new source application is filed generally may not be used for emissions offset credit. However, where an applicant can establish that it shut down or curtailed production after August 7, 1977, or less than one year prior to the date of permit application, whichever is earlier, and the proposed new source is a replacement for the shutdown or curtailment credit for such shutdown or curtailment may be applied to offset emissions from the new source;

(d) No emissions credit may be allowed for replacing one hydrocarbon compound with another of lesser reactivity, except for those compounds listed in Table 1 of EPA's "Recommended Policy on Control of Volatile Organic Compounds." (42 FR 35314, July 8, 1977);

(e) All emission reductions claimed as offset credit shall be federally enforceable;

(f) Procedures relating to the permissible location of offsetting emissions shall be followed which are at least as stringent as those set out in 40 CFR Part 51 Appendix S, section IV.D.

(g) Credit for an emissions reduction can be claimed to the extent that the reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR 51.18 or state has not relied on it in demonstrating attainment or reasonable further progress.

(4) Each plan may provide that the provisions of this subsection do not apply to a source or modification that would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;
(t) Chemical process plants;
(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(w) Taconite ore processing plants;
(x) Glass fiber processing plants;
(y) Charcoal production plants;
(z) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;
(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(5) Each plan shall include enforceable procedures to provide that:

(i) Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provision of the plan and any other requirements under local, state or federal law.

(ii) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforcement limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirments of regulations approved pursuant to this section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

Restrictions on Construction For Nonattainment Areas

5. 40 CFR 52.24 is amended by adding new paragraphs (f), (g), (h) and (i) to read as follows:

§ 52.24 Statutory restriction on new stationary sources.

* * * * *

(f) The following definitions shall apply under this section.

(1) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

(2) "Building, structure, or facility" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same two-digit code) as described in the following document, *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(3) "Installation" means an identifiable piece of process equipment.

(4) "Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(5)(i) "Major stationary source" means:

(a) Any stationary source of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act; or

(b) Any physical change that would occur at a stationary source not qualifying under paragraph (5)(i)(a) as a major stationary source, if the change would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile for organic compounds shall be considered major for ozone.

(6)(i) "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is considered significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(a) Routine maintenance, repair, and replacement;

(b) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(c) Use of an alternative fuel by reason of an order or rule under section 125 of the Act;

(d) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) Use of an alternative fuel or raw material by a stationary source which:

(1) The source was capable of accommodating before July 1, 1979, unless such change would be prohibited under any federally enforceable permit condition which was established after July 1, 1979 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24; or

(2) The source is approved to use under any permit issued under regulations approved pursuant to 40 CFR 51.18;

(f) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after July 1, 1979 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 or 40 CFR 51.24.

(g) Any change in ownership at a stationary source.

(7)(i) "Net emissions increase" means the amount by which the sum of the following exceeds zero:

(a) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(b) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(ii) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:

(a) The date five years before construction on the particular change commences and

(b) The date that the increase from the particular change occurs.

(iii) An increase or decrease in actual emissions is creditable only if the Administrator has not relied on it in issuing a permit for the source under regulations approved pursuant to 40 CFR 51.18 which permit is in effect when the increase in actual emissions from the particular change occurs.

(iv) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(v) A decrease in actual emissions is creditable only to the extent that:

(a) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

(b) It is federally enforceable at and after the time that construction on the particular change begins; and

(c) The Administrator or reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR 51.18 or the State has not relied on it in demonstrating attainment or reasonable further progress.

(d) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(vi) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(8) "Emissions unit" means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(9) "Reconstruction" will be presumed to have taken place where the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable entirely new stationary source. Any final decision as to whether reconstruction has occurred shall be made in accordance with the provisions of 40 CFR 60.15(f) (1)–(3). A reconstructed stationary source will be treated as a new stationary source for purposes of this subsection.

(10) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(11) "Secondary emissions" means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this section, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions may include, but are not limited to:

(i) Emissions from ships or trains coming to or from the new or modified stationary source and

(ii) Emissions from any offsite support facility which would not otherwise be constructed or increase its emissions as a result of the construction or operation of the major stationary source or major modification.

(12) "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(13) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy

(14) "Allowable emissions" means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(i) The applicable standards set forth in 40 CFR Parts 60 and 61;

(ii) Any applicable State Implementation Plan emissions limitation, including those with a future compliance date; or

(iii) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(15) "Federally enforceable" means all limitations and conditions which are

enforceable by the Administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.18 and 51.24.

(16)(i) "Actual emissions" means the actual rate of emissions of a pollutant from an emissions unit, as determined in accordance with subparagraphs (ii)–(iv) below.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(17) "Construction" means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification) of an emissions unit which would result in a change in actual emissions.

(18) "Commence" as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(i) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(19) "Necessary preconstruction approvals or permits" means those permits or approvals required under federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(20) "Begin actual construction" means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operations, this term refers to those on-site activities other than preparatory activities which mark the initiation of the change..

(g) This section shall not apply to a major stationary source or major modification if the source or modification was not subject to 40 CFR Part 51 Appendix S, as in effect on January 16, 1979, and the owner or operator:

(1) Obtained all final federal, state, and local preconstruction approvals or permits necessary under the applicable State Implementation Plan before August 7, 1980;

(2) Commenced construction within 18 months from August 7, 1980, or any earlier time required under the applicable State Implementation Plan; and

(3) Did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time.

(h) This section shall not apply to a source or modification that would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(1) Coal cleaning plants (with thermal dryers);

(2) Kraft pulp mills;

(3) Portland cement plants;

(4) Primary zinc smelters;

(5) Iron and steel mills;

(6) Primary aluminum ore reduction plants;

(7) Primary copper smelters;

(8) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(9) Hydrofluoric, sulfuric, or nitric acid plants;

(10) Petroleum refineries;

(11) Lime plants;

(12) Phosphate rock processing plants;

(13) Coke oven batteries;

(14) Sulfur recovery plants;

(15) Carbon black plants (furnace process);

(16) Primary lead smelters;

(17) Fuel conversion plants;

(18) Sintering plants;

(19) Secondary metal production plants;

(20) Chemical process plants;

(21) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(22) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(23) Taconite ore processing plants;

(24) Glass fiber processing plants;

(25) Charcoal production plants;

(26) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(27) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(i) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then:

(1) If the construction moratorium imposed pursuant to this section is still in effect for the nonattainment area in which the source or modification is located, then the permit may not be so revised; or

(2) If the construction moratorium is no longer in effect in that area, then the requirements of 40 CFR 51.18(j) shall apply to the source or modification as though construction had not yet commenced on the source or modification.

Consolidated Permit Regulations

6. 40 CFR Part 124 is amended as follows:

a. 40 CFR 124.3(b) is deleted and reserved as follows:

§ 124.3 Application for a permit.

* * * * *

(b) [Reserved]

* * * * *

§ 124.5 [Amended]

b. 40 CFR 124.5(g)(2) is revised as follows:

* * * * *

(g) * * *

(2) PSD permits may be terminated only by rescission under § 52.21(w) or by automatic expiration under § 52.21(r). Applications for rescission shall be processed under § 52.21(w) and are not subject to this Part.

§ 124.42 [Amended]

c. The first sentence of 40 CFR 124.42(b) is amended by substituting "submitted" for "requested."

[FR Doc. 80-23788 Filed 8-6-80; 8:45 am]
BILLING CODE 6560-01-M

PART 320—SUSPENSION OF THE PRIVATE EXPRESS STATUTES

4. New § 320.7 is added reading as follows:

§ 320.7 Suspension for advertisements accompanying parcels or periodicals.

(a) The operation of 39 U.S.C. 601(a) (1) through (6) and § 310.2(b) (1) through (6) of this chapter is suspended on all post routes for advertisements enclosed with merchandise in parcels or accompanying periodicals under the following circumstances:

(1) The advertisements must not be marked with the names or addresses of the intended recipients.

(2) The advertisements must be incidental to the shipment of the merchandise or the periodical.

(i) An advertisement is incidental to the shipment of the accompanying merchandise or the periodical when the merchandise or the periodical has been ordered by or would otherwise be sent to the recipient even without the accompanying advertisement.

(ii) Notwithstanding § 320.7(a)(2)(i), an advertisement is not incidental to the merchandise when the pertinent circumstances, such as the nominal value of the merchandise, its shipment on an unsolicited basis, or its status as a sample, reasonably indicate that the shipper's primary purpose is the conveyance of the advertisement itself and that the merchandise is merely an adjunct to the advertisement.

(b) An item is an advertisement if its primary purpose is to cause or induce the purchase of goods or services from the shipper or others.

(39 U.S.C. 401, 404, 601–606; 18 U.S.C. 1693–1699, 1724)

W. Allen Sanders,

Associate General Counsel.

[FR Doc. 80-28090 Filed 9-9-80; 11:07 am]

BILLING CODE 7710-12-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[FRL 1595-3]

Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Emission Offset Interpretative Ruling

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action makes certain revisions to EPA's Emission Offset Interpretative Ruling of January 16, 1979, 44 FR 3274, as revised on May 13, 1980, 45 FR 31307 and August 7, 1980, 45 FR 52676. That Ruling describes the requirements for preconstruction review which apply to large new or modified air pollution sources affecting areas with air quality worse than the levels set to protect the public health and welfare. The revisions made today are in response to EPA's request for comments on certain issues related to the Ruling (*see* 44 FR 3298). Although the Ruling generally expired as of July 1, 1979 (*see* 44 FR 38471, July 2, 1979), it continues to apply to permits applied for before July 1, 1979, and in certain other situations. The changes made today are primarily non-substantive changes. Substantive changes affecting source applicability were proposed September 5, 1979 (44 FR 51924) and final regulations were promulgated on August 7, 1980 in response to the comments received on that proposal. 45 FR 52676.

DATES: These changes are applicable to permits applied for on or after September 11, 1980..

ADDRESS: EPA has established a docket for this rulemaking, designated Docket No. A–80–43. The docket is an organized and complete file of all information submitted to or otherwise considered by EPA during this rulemaking. The docket is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery I, A–130, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Kirt Cox, Office of Air Quality Planning and Standards, Environmental Protection Agency, MD–15, Research Triangle Park, North Carolina 27711, Phone: (919)541–5497.

SUPPLEMENTARY INFORMATION:

I. Background

On December 21, 1976, EPA issued an Emission Offset Interpretative Ruling (Offset Ruling) addressing the issue of the extent to which National Ambient Air Quality Standards (NAAQS) established under the Clean Air Act may restrict construction of major new or modified stationary air pollution sources. 41 FR 55524. The Ruling provided, in general, that a proposed major new source, which would emit pollutants in excess of specified amounts and would otherwise contribute to an existing violation of a national standard, could be constructed only if stringent conditions were met. These conditions were designed to ensure that the new source's emissions would be controlled to the greatest degree possible, that more than equivalent offsetting emission reductions ("emission offsets") would be obtained from existing sources, and that there would be progress toward achievement of the NAAQS.

Since the issuance of the December 21, 1976 Offset Ruling, the Agency's programs for preconstruction review of major new sources and major source modifications have been the subject of considerable legislative and regulatory change. Pertinent Federal Register actions incorporating these changes are noted below.

The Clean Air Amendments of 1977 (1977 Amendments) ratified the Agency's Offset Ruling. Section 129 of Pub. L. No. 95–95, 91 Stat. 685, note under 42 U.S.C. 7502. The amendments also established definitions for "major sources. The issues of what size source and the circumstances under which a source should be subject to review were first addressed in the Agency's June 19, 1978 regulatory amendments to the New Source Review Program for the Prevention of Significant Deterioration (PSD) of air quality. 44 FR 26388.

After promulgating the PSD regulations, the Agency turned its attention to the Offset Ruling. As a result of comments received in amending the PSD regulations (43 FR 26380), comments on the original Offset Ruling (41 FR 55524), and the unambiguous language of the 1977 Amendments, the Agency published revisions to the Offset Ruling on January 16, 1979. 44 FR 3274. Most of the revisions were made final at that time, rather than proposed again for comment. Certain issues were proposed as interim policy and comment was solicited on these issues. 44 FR 3298.

On July 2, 1979, the Agency published regulations restricting the construction of major sources, as required by the 1977 Amendments, wherever State plans to attain and maintain NAAQS have not been approved by July 1, 1979. 44 FR 38471. For those areas, the Offset Ruling—which allows sources to "offset" their pollution and still construct—is superseded by the Act's restrictions against construction.

Additional action, primarily dealing with PSD but also affecting the scope of preconstruction review of new sources under the Offset Ruling, was proposed on September 5, 1979 (44 FR 51924) and promulgated on August 7, 1980. 45 FR 52675. That promulgation brought significant changes to the Agency's rules and regulations for preconstruction review, in response to a court interpretation of EPA's preconstruction review regulations for PSD. *Alabama Power Company v. Costle*, 13 ERC 1980

(D.C. Cir., 1979). This action does not address the issues dealt with in the August 7, 1980 promulgation.

Also, on May 13, 1980, (45 FR 31307) EPA took final action on certain of the changes to the Offset Ruling proposed on September 5, 1979. At that time, EPA eliminated the "clean spot" exemption from the Offset Ruling and gave guidance for State new source review permit programs adopted pursuant to Section 110(a)(2)(D) of the Clean Air Act. It also provided that the Offset Ruling will continue to apply to sources locating outside of nonattainment areas, but causing or contributing to a violation of ambient standards, until the State's permit or equivalent program under Section 110(a)(2)(D), providing for review of such sources to assure attainment and maintenance of the NAAQS, is approved by EPA.

As a result of the above actions, the Offset Ruling continues to apply to the following situations: (a) To proposed major sources in one State that would contribute to a violation of a NAAQS only in another State, (b) during the time allowed for the development and approval of a revised State Implementation Plan (SIP) in an area that is designated as nonattainment after March 3, 1978, (c) during any extended time allowed under Section 110(b) for development of a SIP revision for an area that violates the secondary NAAQS (and for which a plan for the primary NAAQS is either approved or not required) for a pollutant, and (d) proposed major sources locating outside of nonattainment areas but causing or contributing to a nonattainment problem until the State's permit or equivalent program is approved by EPA.

As noted, when the Agency published the January 16, 1979 Offset Ruling, it requested comments on certain issues contained therein. 44 FR 3274, 44 FR 3298. In this Federal Register action, the Agency is responding to comments made in response to that notice. Clarifications are made to the Offset Ruling with regard to technology transfer in determining LAER and the permissible area of offsets for NO_x sources. LAER requirements for secondary emissions are changed. Also, supplemental guidance is given on issues concerning the offset credit for meeting NSPS, the baseline for offsets, source compliance certification, fugitive dust, ownership, and banking. Certain issues on which the Agency solicited comments on January 16, 1979 were addressed by the August 7, 1980 promulgation and therefore are not discussed here. Those issues include those involved in the definitions of "potential to emit," "source," and "modification," the 50-ton exemption, rules relating to fugitive dust, and the geographic applicability of the Offset Ruling to major sources of volatile organic compounds.

In addition to the discussion of issues found in the August 7, 1980 Federal Register and in the supplementary information given below, the Agency has also responded to a number of issues in a separate document entitled, "Supplemental Discussion of Comments Received on Revised Emission Offset Ruling" (44 FR 3274, January 16, 1979, Office of Air, Noise, and Radiation, June 1980). The supplementary discussion document, as well as all the comments received in response to the January 16, 1979 Offset Ruling, are available for public inspection and copying during normal business hours at: Central Docket Section, West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. The discussions in that document relate to issues raised by comments which did not result in changes to the Offset Ruling and did not require further clarification as to EPA's policy or intent. Furthermore, none of the issues discussed in that document are issues on which the Agency solicited comment. 44 FR 3298.

II. Technology Transfer in LAER

A number of industrial commenters argued that there is no statutory authority to consider transfer of technology from one source type to another in determining the lowest achievable emission rate (LAER). The Agency affirms that the requirements for technology transfer appropriately incorporate Congressional intent, as discussed in the supplemental information to the January 16, 1979 ruling. There is considerable precedent for this approach. Technology transfer is authorized with regard to determining best available control technology for purposes of the New Source Performance Standards under Section 111 of the Clean Air Act. This approach is also supported by the fact that consideration of technology transfer has been found appropriate in determining effluent emission limits for water pollution control cases. *See, e.g., California and Hawaiian Sugar Co. v. EPA*, 553 F. 2nd 280, 285–289 (2nd Cir. 1977).

Many of these commenters went on to indicate that EPA's policy on technology transfer would be acceptable if implemented "reasonably," *i.e.*, that technological and economic feasibility be considered, that there be a reasonable degree of certainty that the transferred technology would work for the *specific* application under consideration, and that pilot studies or other appropriate techniques be used to verify transferability. In short, the commenters requested that good engineering judgment be used in determining whether technology transfer is applicable and feasible in a particular situation and what the effectiveness of such technology would be. EPA agrees and believes that considerations of feasibility are appropriate in using technology transfer in determining LAER. But EPA maintains that consideration of the transfer of technology from one source type to another is appropriate in determining LAER. Technology transfer which would cause an unduly severe economic penalty or would be technologically infeasible for the specific application under consideration need not be included in establishing the lowest achievable emission rate.

The Agency does not intend, in this statement of policy, to establish separate economic criteria for LAER for technology transfer. Consideration of economic feasibility is the same under LAER regardless of whether technology transfer is involved.

III. Nitrogen Oxides Issues

The January 16 revision to the Offset Ruling indicates that, due to the generally area-wide nature of NO_2 problems, offsets for NO_x sources may be obtained from "within the broad area of nonattainment." One commenter interpreted this language to mean that NO_x offsets must be obtained from within the designated nonattainment area for NO_2. EPA did not intend such a restrictive interpretation regarding the location of NO_x offsets. Section IV.D. is hereby amended to clarify that volatile organic compounds and NO_x should be treated consistently and, therefore, that NO_x offsets may come from nearby attainment or unclassifiable areas as well as from a designated nonattainment area.

Several commenters indicated that there is no basis for the assumption in Section III.C. (as amended, May 13, 1980, 45 FR 31307, 31311) that all NO_x emitted from a source is converted to NO_2 by the time the plume reaches the ground. This assumption is only intended as a screening technique; if the source would not significantly contribute to an NO_2 nonattainment problem under this "worst case" assumption, no further requirements under the Ruling would apply. However, if a potential problem is indicated by this screening technique, a more refined analysis will be necessary.

IV. Offset Credits

The Agency does not, at this time, make any changes to Section IV.C. of the Offset Ruling in response to comments received regarding the baseline for offsets. The Agency has recently promulgated somewhat different rules for determining when intra-source offsets may be used to avoid a preconstruction permit review (*e.g.* under the Offset Ruling for a modification that would otherwise be subject to full permit review and requirements. 45 FR 52675 (August 7 1980)). The baseline for offset credits that is discussed below refers to sources that are subject to the Offset Ruling and must find sufficient emission offsets to meet the requirements of Conditions 3 and 4 of the rule, *i.e.*, sufficient emission offsets to represent reasonable further progress toward attainment, and to provide for a net air quality benefit in the area affected by the new source or modification.

The Clean Air Act Amendments of 1977 required that the baseline for determining emission offset credit, under the Offset Ruling, was to be the SIP emission limitations in effect at the time of the permit application. In the January 16, 1979 Offset Ruling changes, the Agency amended the Ruling to incorporate this legislative requirement. Thus, Section IV.C. of the Offset Ruling provides that if, for example, a SIP allows SO_2 emissions of 3.0 lb/10^6 Btu for all fuels, an existing source burning fuel oil with SO_2 emission of 1.0 lb/10^6 Btu could use the difference between 3.0 and 1.0 lb/10^6 Btu as offset credit.

Thus, in such a case, if the source agreed to the imposition of a legal obligation to maintain SO_2 emissions below SIP levels, the source could obtain offset credit.*

However, the Agency has retained its Section IV.C.1. requirement that where the SIP emission limit is higher than the source could emit without any controls, then the uncontrolled emission rate itself establishes its offset baseline for the source. The wording in Section IV.C.1. is changed to assure that the uncontrolled emission rate remains the offset baseline. In that section, the word "potential" is changed to "uncontrolled." This is being done now because the definition of "potential to emit" now looks to the source's controlled emissions.

Specific clarification on Section IV.C.1. was sought regarding sources burning natural gas, where the maximum uncontrolled emissions for natural gas combustion are in the neighborhood of .0006 lb/10^6 Btu. To allow offset credits for emissions up to a general SO_2 emission limit in the SIP of 3.0 lb/10^6 Btu, would allow credit far beyond what Congress intended in the 1977 Amendments. In such a case, the uncontrolled emission rate establishes the offset baseline for the source.

Similar clarification is now offered regarding offset credit for meeting NSPS and NESHAPS requirements. The baseline discussion in the preamble to the January 16, 1979 ruling (44 FR 3274–3275) indicated that EPA does not interpret the Ruling to permit offset credit for tightening SIP requirements down to the levels required by an applicable new source performance standard (NSPS) or national emission standard for hazardous air pollutants (NESHAPS), *i.e.*, requirements under Sections 111 and 112, respectively, of the Act. Comments reflected considerable misunderstanding and uncertainty as to EPA's policy on this issue, especially where an NSPS was concerned. EPA's intent was that, where a source is *subject* to an NSPS or NESHAPS emission limitation that is more stringent than the otherwise applicable SIP, the difference in emissions between the SIP and the NSPS or NESHAPS for such source may not be used as offset credit. As discussed in the January 16, 1979 preamble, any other approach would allow offset credit for "paper" reductions, where the SIP is adjusted but no actual tightening of requirements under the act occurs. However, if a source were not subject to an NSPS, for example if it were constructed *before* an NSPS was proposed for that source category, offset credit could be permitted for tightening the SIP to the NSPS level for such source. The general philosophy here is to permit offset credit only for controls that go beyond applicable State or federal emission limitations in effect for existing sources at the time an application for a new source permit is applied. A new Section IV.C.6. is added to the Offset Ruling to remove any uncertainty on this issue. Although one commenter recommended that this policy not be made applicable before January 16, 1979, EPA believes that the policy is fully consistent with the philosophy and intent of the original Ruling and thus should apply to all permits issued under it.

Several commenters also argued that a January 16, 1979 clarification in Section IV.C. as to how to calculate offset credits in terms of tons per year was a major change to the Ruling and should have been proposed for public comment prior to making the change. Specifically, these commenters felt that EPA's use of actual annual operating hours for the previous one or two year period (in conjunction with the SIP emission limit) was inconsistent with Section 129 of the 1977 Amendments. They felt that if there were no SIP requirements limiting the operating hours for an existing source, the baseline emissions for calculating offset credits available from such a source should be based on the maximum possible operating hours in a year. EPA does not believe that Section 129 of the 1977 Amendments, which specifies that the applicable SIP is to be used as the baseline for determining offset credit, requires that the maximum possible operating hours be used when determining creditable offsets in tons per year. Such an interpretation would create massive amounts of "paper offsets" which bear no relationship to the actual amount of offsets being obtained. EPA believes it is more realistic and consistent with Congressional intent to use the applicable SIP emission limit in conjunction with the *actual* number of annual operating hours for the prior one or two year period. Furthermore, the clarification contained in the revised Ruling is fully consistent with the intent and specific language of the original Ruling. For example, Section IV.C.3 of the original Ruling provides that "[a] source may be credited with emission reductions achieved by shutting down an existing source or permanently curtailing production or operating hours *below that which existed at the time the new source permit was submitted* * * *" (emphasis added). The original Ruling has been applied consistently with the clarification contained in the revised Ruling.

Several commenters indicated that credit for source shutdowns occurring *prior* to the date a new source permit is filed should not be limited to only replacement facilities. Credit is limited in that fashion by Section IV.C.3. and footnote 6. The Agency is retaining this approach. EPA responded in this manner because it is preparing comprehensive regulations regarding banking of emissions reductions to allow for future new source growth. These are a variety of interrelated

*This approach is somewhat different from that used in 40 CFR 51.18 (j). There, the emission offset baseline, while it ordinarily will be calculated on the basis of allowable emissions, may look to actual emissions if the State's demonstration of reasonable further progress (RFP) is based on actual emissions. This difference in approach is due to the fact that Congress required the baseline to be allowable emissions for the Offset Ruling, *see* Section 129(a)(1) of the 1977 Amendments, whereas under Section 173, offsets must be consistent with RFP and so the baseline may be either actual or allowable emissions, depending on the nature of the RFP demonstration.

issues involved in this matter and the Agency believes that this offset requirement would be best addressed in the banking rulemaking.

Finally, one commenter recommended that a major new source be allowed to secure offsets from small sources, mobile sources, and nonpoint sources. There is nothing in the Ruling that precludes such offsets, as long as all the other requirements of the Ruling are met. Offset credit is not permitted for reductions in mobile source emissions achieved by the Federal Motor Vehicle Control Program. Offset credit may be obtained by reducing mobile source emissions by other means, *e.g.*, inspection and maintenance programs or transportation controls that are not required by the SIP at the time the new source permit is applied for. It is clear that special problems of enforceability exist with regard to such offsets. For this reason it is emphasized that close scrutiny of the enforceability of such offsets must be given.

V. Certification of Compliance Under Condition 2

Several commenters raised issues relating to Condition 2 of Section IV.A. which requires a new source applicant to certify that all existing major sources in the same State owned or operated by the applicant are in compliance with all applicable standards under the Act, or are on federally enforceable compliance schedules.

One commenter argued that under the Clean Air Act, a source owner does not bear the responsibility of reporting violations discovered through continuous self-monitoring and that the burden of identifying violations is on EPA. Others claimed that a source owner may have a good faith belief, yet lack information to be able to certify that Condition 2 is being met. It was suggested that sources should be deemed in compliance unless a source has received a Notice of Violation and judicial proceedings have actually been commenced. Another commenter urged that the Ruling specify that only established noncompliance need be considered during certification. One industry association suggested that Condition 2 would be satisfied by certifying that existing major sources in the same State owned or operated by the applicant are not currently subject to any final civil or criminal judgment of noncompliance by any State court or Federal court.

It is not correct that under the Clean Air Act the sole responsibility for determining compliance with regulations adopted pursuant to the Act rests with EPA or State and local agencies. In most cases, sources are not required by regulation to report their noncompliance; however, the lack of a requirement to report violations in no way excuses the source from the requirement to comply at all times and to employ specified methods and procedures for assessing compliance status. The burden is clearly on the source to do whatever is necessary to assure compliance. The duty to comply clearly includes the duty to ascertain compliance status. Furthermore, Section 173(3) of the Clean Air Act provides that permits to construct and operate may be issued only if:

> * * * the owner or operator of the proposed new or modified source *has demonstrated* that all major stationary sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in such State are subject to emission limitations and are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards under this Act. (emphasis added)

In order to demonstrate that Condition 2 is being met, an owner or operator should certify that its sources are in compliance and provide supporting evidence. Types of evidence could include performance test results, continuous monitoring results, if such a system is used, a demonstration that required control devices are in place and operating at design efficiency, and a demonstration that required operating and maintenance procedures are being followed. Where compliance is based on the use of a certain type or sulfur content of a fuel, the use of the type or sulfur content fuel must be documented.

Industry suggested that the absence of criminal or civil legal action against the source should be accepted as a sufficient indication of compliance. This is not only without legal support, but also unworkable. While EPA and the States have undertaken an accelerated enforcement effort, many sources remain in violation which have not yet been the subject of judicial action under the Clean Air Act. If this suggestion were implemented, EPA and the States would have to postpone action on a permit application until all cases of suspected noncompliance by sources owned or operated by the applicant were adjudicated. The result would be long delays in the permitting process, a loss by the States and EPA of control over judicial enforcement priorities, and an inappropriate shift of the burden of demonstrating compliance from the source to EPA and the States.

VI. Fugitive Dust

By its August 7, 1980 rulemaking, the Agency deleted the provisions which embody the exemption of fugitive dust from air quality analyses performed pursuant to the Offset Ruling and the definition of fugitive dust (emissions from haul roads, storage piles, etc.). 45 FR 52675, 52693 and 52741.

The requirements for offsets and LAER for fugitive dust emissions associated with a major source remain unchanged. Many industrial comments received on the January 16, 1979 changes to the Offset Ruling opposed subjecting fugitive dust associated with a major source to the requirements of the Ruling, citing the following reasons:

1. Fugitive dust emissions are difficult to quantify.
2. Fugitive dust is different (i.e., coarser) than other particles.
3. Only a portion of the fugitive dust emissions remains airborne.
4. Offsets for particulate matter are hard to find.

EPA believes that none of these reasons provides a basis for totally exempting fugitive dust from the Ruling. EPA recognizes that some problems exist in quantifying fugitive dust emissions, and in fact has and will continue to devote significant resources to improving emission factors for fugitive dust sources. However, EPA believes that reasonable quantification of fugitive dust emissions can be made for most sources on the basis of available data, and thus those sources should be covered by the Ruling. Determinations made on a case-by-case basis will indicate those instances in which fugitive dust cannot be quantified and would, therefore, not be considered. Under the regulations promulgated August 7, 1980, fugitive dust emissions (haul roads, storage piles, etc.) and fugitive process emissions of certain designated source categories are to be included in determining whether or not specified source categories are subject to review. 45 FR 52675, 52690–3.

One commenter sought clarification on the use of high volume sampling methods used to determine the need for fugitive dust offsets. Although fugitive dust is generally coarser than other particulate emissions, much of the fugitive dust is still in the particle size range measured by the high volume sampler. It is not EPA's intent that offsets be required for those very large fugitive dust particles which are not generally captured by the high volume sampler. In fact, most fugitive dust emission factors do not include these large particles and no special adjustments to the emission rates would

normally be necessary to implement this policy.

Several commenters contended that LAER could not be defined for fugitive dust sources. Paradoxically, one of these commenters went on to recommend that only BACT be required for fugitive dust sources. EPA sees no reason why LAER could not be defined for fugitive dust sources although in most cases it will take the form of operating or equipment standards rather than a numerical emission rate.

VII. Definition of Control

A permit issuing authority must determine when one business is in "control" of another, for three purposes under the Ruling. First, a stationary source is defined as embracing a grouping of industrial activities on contiguous or adjacent properties owned or operated by the same person or by persons "under common control." Second, the State-wide compliance requirement of Condition 2 applies to major sources owned by the applicant or by any entity "controlling, controlled by, or under common control with" the applicant. Third, secondary emissions that are not under the control of the permit applicant are not subject to the State-wide compliance requirement of Condition 2.

Control can be a difficult factual determination, involving the power of one business entity to affect the construction decisions or pollution control decisions of another business entity. EPA thought that a simplifying test of control, such as some specified voting share, would serve the interest of the business community, by providing clarity and predictability. Comments on this issue were solicited and suggestions were received. Upon receiving the comments, the Agency did not find a convincing argument in favor of any particular, simplified test of control. Some commenters seemed to favor unfettered inquiry into control in each case. Therefore, the Agency has decided that determinations of control will be made case-by-case, without benefit of a voting-share test or other simplifying test. However, the Agency will be guided by the general definition of control used by the Securities and Exchange Commission. In SEC considerations of control, control "means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association) whether through the ownership of voting shares, contract, or otherwise." 17 CFR 210.1-02(g). This definition is similar to a suggestion made by a commenter.

VIII. Banking

EPA has received many comments on banking. Most commenters view banking favorably, citing a number of advantages for it. Some commenters questioned the limitation in Section IV.C.5. which restricts banking to permits issued after January 16, 1979. Allowing retroactive application of banking would result in previously issued permits being reopened and excess offsets being banked for future use. The Agency is not changing this aspect of the Offset Ruling.

Under the Clean Air Act Amendments, States may, as part of their SIPs, allow emissions reduction banking and trading as long as care is taken to assure that use of banked emissions is enforceable, does not violate reasonable further progress requirements of Part D of the Act and does not block ultimate attainment. Only emissions reductions not needed for and not included in the SIP attainment demonstration could be used in permit applications.

EPA is now studying alternative approaches to banking emissions and will provide information and assistance where this is requested. The specific issues to be addressed will include the creation and use of banked emission reductions as well as the development of safeguard measures to assure the integrity of the SIP.

Since EPA considers economic efficiency and the accommodation of growth in nonattainment areas to be important national goals, it is also devoting resources to the development of "prototype" emission reductions banking and trading systems which States and local areas have the option of adopting in whole or in part. Technical information, management systems workshops, and published manuals are being developed as part of this work. EPA work in these areas is being coordinated through the Division of Policy Planning in the Office of Planning and Evaluation which is part of the Office of Planning and Management. Parties seeking further information or assistance are invited to contact John S. Hoffman, Project Manager, PM-221, 401 M Street, S.W., Washington, D.C. 20460.

IX. Secondary Emissions

The Agency, on August 7, 1980, promulgated into the PSD regulations the same definition of secondary emissions as is now found in the Offset Ruling. 45 FR 52675, 52728. The Agency also promulgated its proposal that best available control technology (BACT) not be required for any secondary emissions subject to review under the PSD regulations. Consequently, secondary emissions will only be considered in, and subject to, the air quality impact analysis requirements in the PSD preconstruction review. Thus, if a source's secondary emissions would cause an increment violation, they would have to be controlled or offset before a permit could be issued, but BACT will not be required for the secondary emissions.

Commenters have stated, both before and in response to the January 16, 1979 rulemaking, that sources of secondary emissions should not be subject to LAER. The Agency has reconsidered its policy and has decided to take an approach parallel to the one adopted in the PSD regulations. This policy was noted in the preamble to the August 7, 1980 rulemaking, *See* 45 FR 52676, 52689, but the Agency neglected to make the corresponding change in the regulation. Therefore, this requirement for application of LAER to sources of secondary emissions is being deleted at this time.

X. Miscellaneous

Due to a typographical error in the January 16, 1979 **Federal Register**, the reference to footnote 3 (which was designated as footnote 5 prior to the August 7, 1980 promulgation) in Section IV.A. was incorrectly placed in Condition 2 rather than Condition 3. This is corrected in the amendment of the Offset Ruling set forth below.

XI. Authority

The Administrator has determined that this rulemaking is nationally applicable and is based on determinations of nationwide scope and effect. This rulemaking is issued under Section 129(a) of the Clean Air Act Amendments of 1977, Pub. L. 9595, 91 Stat. 745, August 7, 1977 (note under 42 U.S.C. 7502 and Section 301 of the Clean Air Act (42 U.S.C. 7601)).

Under Executive Order 12044 EPA is required to judge whether a regulation is "significant" and therefore subject to the procedural requirements of the Order or whether it may follow other specialized development procedures. EPA labels these other regulations "specialized." I have reviewed this regulation and determined that it is a specialized regulation not subject to the procedural requirements of Executive Order 12044.

By this notice, EPA advises prospective petitioners, as well as those who may seek review of EPA's promulgation on August 7, 1980 (45 FR 52675), that a court order governs petitions for review of today's action and the nonattainment petitions of the August 7 rulemaking. This order was

entered in *Manufacturing Chemists Association* v. *EPA*, No. 79–1112, and consolidated cases Nos. 79–1251, 79–1257, 79–1283, 79–1291, 79–1295, 80–1770, and 80–1777 (D.C. Cir.). The court order states that "regardless of when they file petitions for review, prospective petitioners are to file their opening briefs in accordance with [the following briefing] schedule, and to join with other petitioners raising identical or similar issues in common briefs * * *." The schedule is as follows:

Supplemental index to the record	30 days after the date of this Federal Register notice
Petitioners' brief	45 days after the filing of the supplemental index
Respondent's brief	40 days after the filing of petitioners' briefs
Petitioners' reply briefs	25 days after filing of respondent's brief
Joint appendix	7 days after the filing of reply briefs
Final printed briefs	14 days after the filing of the joint appendix

The order was entered on September 10, 1979.

The Administrator has also determined that there is good cause to make this promulgation immediately effective because the changes are either non-substantive in nature or constitute clarification.

Dated: September 5, 1980.

Douglas M. Costle,

Administrator.

The Emission Offset Interpretative Ruling, 40 CFR Part 51 Appendix S, as revised 44 FR 3274 (January 16, 1979), 45 FR 31307 (May 13, 1980) and 45 FR 52676 (August 7, 1980) is amended as follows:

1. In Section II.G. the third sentence is changed to read as follows:

G. *Secondary emissions.*

* * * * *

However, secondary emissions may be exempt from Conditions 1 and 2 of Section IV.

* * * * *

2. In Section IV.A., the reference to footnote 3 (which was designated as footnote 5 prior to the August 7, 1980 promulgation) is removed from Condition 2 and is inserted in Condition 3 following the word "sources."

3. In Section IV.C.1 the word "potential," which appears twice in the second paragraph is changed in both places to read "uncontrolled."

4. In Section IV.C., a new subsection 6 is added as follows:

IV. Sources That Would Contribute to Concentrations That Would Exceed a NAAQS

* * * * *

C. *Baseline for determining credit for emission and air quality offsets.*

* * * * *

6. *Offset credit for meeting NSPS or NESHAPS.* Where a source is subject to an emission limitation established in a New Source Performance Standard (NSPS) or a National Emission Standard for Hazardous Air Pollutants (NESHAPS), (*i.e.*, requirements under Sections 111 and 112, respectively, of the Act), and a different SIP limitation, the more stringent limitation shall be used as the baseline for determining credit for emission and air quality offsets. The difference in emissions between the SIP and the NSPS or NESHAPS, for such source may not be used as offset credit. However, if a source were not subject to an NSPS or NESHAPS, for example if its construction had commenced prior to the proposal of an NSPS or NESHAPS for that source category, offset credit can be permitted for tightening the SIP to the NSPS or NESHAPS level for such source.

5. In section IV.D., the second paragraph is amended by changing the first sentence of that paragraph to read as follows:

D. *Location of offsetting emissions.*

* * * * *

Offsets for NO_x sources may also be obtained within the broad vicinity of the proposed new source.

* * * * *

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Part III

Environmental Protection Agency

Emissions Trading Policy Statement; General Principles for Creation, Banking, and Use of Emission Reduction Credits

ENVIRONMENTAL PROTECTION AGENCY

[PRM-FRL-1994-5]

Emissions Trading Policy Statement; General Principles for Creation, Banking, and Use of Emission Reduction Credits

May 12, 1982.

AGENCY: Environmental Protection Agency.

ACTION: Proposed policy statement and accompanying technical issues document.

SUMMARY: It is the policy of EPA to encourage use of emissions trades to achieve more flexible, rapid and efficient attainment of national ambient air quality standards.

This Policy Statement describes emissions trading, sets out general principles EPA will use to evaluate emissions trades under the Clean Air Act, and expands opportunities for states and industry to use these less-costly control approaches. Emissions trading includes several alternatives to traditional regulation: bubbles, netting, and offsets, as well as banking (storage) of emission reduction credits (ERCs) for future use. These alternatives do not alter existing air quality requirements; they simply give states and industry more flexibility to meet these requirements. EPA endorses emissions trading and supports its accelerated use by states and industry to meet the goals of the Clean Air Act more quickly and inexpensively.

This Policy Statement replaces the original bubble policy (44 FR 71779, Dec. 11, 1979) and sets forth minimum legal requirements for creation, storage or use of emission reduction credits in any emissions trade. It also provides criteria for "generic" SIP rules under which states can approve bubble or other trades without case-by-case federal SIP review.

EPA encourages states to continue adopting generic trading rules and approving individual trades. Until EPA takes final action on this proposal, it will evaluate state actions under the principles set forth here and illustrated in the accompanying Technical Issues Document.

EFFECTIVE DATE: This Policy Statement is effective as interim guidance upon publication. The deadline for submitting written comments is July 6, 1982.

ADDRESSES: Comments should be sent in triplicate if possible to: Central Docket Section (A-130), U.S. Environmental Protection Agency, Washington, D.C. 20460, Attn: Doc. No. G-81-2.

DOCKET: EPA has established docket number G-81-2 for this action. This docket is an organized and complete file of all significant information submitted to or otherwise considered by EPA. The docket is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section. A reasonable fee may be charged for copying.

FURTHER INQUIRIES:

Ivan Tether, Regulatory Reform Staff (PM-223), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460, (202) 382-2765,

or

Leo Stander, Office of Air Quality Planning and Standards (MD-15), Research Triangle Park, North Carolina 27711, (919) 541-5516.

SUPPLEMENTARY INFORMATION: Under Executive Order 12291, EPA must judge whether this action is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This action is not major because it establishes policies that are voluntary and can substantially reduce costs of complying with the Clean Air Act. Furthermore, it can reduce administrative complexity by reducing the number of trades which must be approved by EPA, can stimulate innovation in pollution control, and can allow state and local pollution control agencies to conserve scarce resources.

This Policy Statement was submitted to the Office of Management and Budget for review. Any comments from OMB to EPA are available for public inspection in Docket G-81-2. Pursuant to 5 U.S.C. 605(b), I hereby certify that this action will not have a significant economic impact on a substantial number of small entities. As a policy designed to allow firms flexibility and to reduce administrative complexity, it will impose no burdens on either small or large entities.

I. Introduction: Components of Emissions Trading

This statement details EPA policy on emissions trading. It presents the minimum conditions EPA considers necessary for emissions trades to satisfy the Clean Air Act. It simplifies past requirements and expands opportunities to use these more efficient alternatives.

A. What Is Emissions Trading?

Emissions trading consists of bubbles, netting, emission offsets, and emission reduction banking. These alternatives involve the creation of surplus reductions at certain emission sources and use of these reductions to meet requirements applicable to other emission sources. Emission trades can provide more flexibility, and may therefore be used to reduce control costs, encourage faster compliance, and free scarce capital for industrial revitalization. Moreover, by developing "generic" trading rules (see section III below) states [1] and industry can be excused from SIP revisions, and attendant delay and uncertainty, for many individual bubbles or other trades.

B. The Bubble Policy and Today's Improvements

EPA's bubble policy lets *existing* plants (or groups of plants) decrease or be excused from pollution controls at one or more emissions sources in exchange for compensating increases in control at other emission sources. Bubbles give plant managers flexibility to develop less costly ways of meeting air quality requirements. Each bubble must be equivalent to the original emission limits in terms of ambient impact and enforceability. Bubbles cannot be used to meet technology-based requirements applicable to new sources.

This Policy Statement replaces the original bubble policy (Dec. 11, 1979; 44 FR 71779) and broadens opportunities for the bubble's use. Major changes include:

- Authorizing generic trading rules for all criteria pollutants;
- Extending use of the bubble to areas which lack approved demonstrations of attainment of the national ambient air quality standards;
- Expanding opportunities for use of bubbles as an alternative means of meeting reasonably available control technology (RACT) requirements;
- Reducing unnecessary requirements for detailed air quality modeling of the ambient impact of each trade;
- Reducing unnecessary constraints on trades involving open dust sources of particulate emissions;
- Allowing VOC and CO sources more time to implement bubbles under administrative compliance schedules, consistent with reasonable further progress and statutory deadlines for attaining ambient standards;
- Allowing sources to use the bubble to come into compliance, instead of having to be on a compliance schedule with original SIP limits to be eligible to bubble; and

[1] "States" includes any entity properly delegated authority to administer relevant parts of a State Implementation Plan (SIP) under the Clean Air Act.

• Allowing broader use of emission reductions from shutdowns.

These and other changes are explained below and in the accompanying Technical Issues Document.

C. Netting

Netting removes the burden of new source review requirements from plants expanding or modernizing in PSD and nonattainment areas, so long as any increase in plant-wide emissions is insignificant. By "netting out" of review the new facility may be exempted from preconstruction permits and associated requirements, including monitoring and modeling, installation of BACT or LAER control technology, the offset requirement, and applicable bans on new construction. The new facility must still meet emission limits established by new source performance standards (NSPS) under Section 111 of the Clean Air Act. Rules governing netting for sources in attainment (PSD) areas were published on August 7, 1980 (45 FR 52676) and rules for nonattainment areas were expanded on October 14, 1981 (46 FR 50766).

D. Emission Offsets

In nonattainment areas, new major stationary sources and modifications may be required to secure sufficient surplus emission reductions to more than "offset" their increased emissions. This requirement is designed to permit industrial growth in nonattainment areas while improving air quality. It is currently implemented by rules published at 40 CFR 51.18(j) and 51.18 (Appendix S), as amended by 45 FR 52676 (August 7, 1980) and 46 FR 50766 (October 14, 1981).

E. Emission Reduction Banking

Banking lets firms store qualified emission reductions for later use in bubble, netting or offset transactions. Banked emission reduction credits (ERCs) can also be sold to firms seeking alternate ways to meet regulatory requirements more quickly flexibly.

EPA's revised offset ruling (40 CFR 51.18, Appendix S) authorized states to establish banking rules as part of their SIPs. This Policy Statement and the Technical Issues Document are EPA's first detailed articulation of the necessary components of a complete state banking rule under the Clean Air Act.

F. Effect of This Policy Statement

Emissions trading is voluntary. States are free to adopt generic rules or let trades continue to be implemented as individual SIP revisions. They may adopt rules which incorporate all or any combination of these trading approaches.

EPA is issuing this Policy Statement as a proposal because elements of emissions trading, particularly banking, raise issues which have not yet been subject to public comment. EPA urges interest parties to address all relevant issues in their comments.

However, until final action the Agency intends to use the principles in this Statement to evaluate trading activities which become ripe for decision, including state adoption of generic bubble and banking rules. Many states are now implementing such rules and should continue to do so.

This Policy Statement is accompanied by a Technical Issues Document for use by states and industry in further understanding emissions trading. The Document offers more detail on minimum requirements and available options under the Clean Air Act. EPA also invites comment on any aspect of the Technical Issues Document.

This notice reflects the current Clean Air Act and existing regulations. A Policy Statement cannot legally alter such requirements. However, it establishes EPA policy in areas not governed by applicable regulations and sets out general principles which states and industry may use to apply those regulations in individual cases. Pending litigation or future rulemaking may alter the general principles outlined here and reflected in the Technical Issues Document. Future federal or state rulemaking, such as additional RACT requirements or changes in ambient standards, may also affect firms that have engaged in emissions trading activities.

II. Minimum Legal Requirements for Creating, Using, and Banking Emission Reduction Credits [1]

A. Creating Emission Reduction Credits

Emission reduction credits (ERCs) are the common currency of all trading activity. To assure that emissions trades do not contravene relevant requirements of the Clean Air Act, only reductions which are *surplus, enforceable, permanent,* and *quantifiable* can qualify as emission reduction credits and be banked or used in an emissions trade.

1. *Surplus:* Only emission reductions not currently required by law can be considered surplus. To define what is surplus, the state must first establish an appropriate emissions baseline against which surplus reductions can be calculated.

In nonattainment areas with approved demonstrations of attainment, the baseline must be consistent with assumptions used to develop the area's SIP. Only reductions not assumed in the area's demonstration of reasonable further progress and attainment can be considered surplus. This generally means that actual emissions must be the baseline where actual emissions were used for such demonstrations, and that allowable emissions may be the baseline where allowable emissions were used for such demonstrations.

In nonattainment areas lacking a demonstration of attainment, states may use a variety of baselines which do not jeopardize attainment by statutory deadlines. In general, states may use as baselines either actual emissions (with source commitment to future reductions if needed for attainment) or emission levels which reflect reasonably available control technology. However, where such areas must attain primary ambient air quality standards by December 1982, baselines reflecting reasonably available control technology for emission sources involved in the trade must be used.

In attainment areas, to be consistent with air quality requirements established in prevention of significant deterioration (PSD) programs under Section 110 and Part C of the Clean Air Act, actual emissions would normally be the baseline. States may use allowable emissions as the baseline, if proper consideration of increment consumption is assured.

2. *Enforceable:* To assure that Clean Air Act requirements are met, each transaction must be approved by the state and be enforceable. Enforceable emission limits may be created through SIP revisions (see Section IV), under generic trading rules (see Section III), through new source construction permits; or through state permits issued under 40 CFR 51.18, among other ways.

3. *Permanent:* Only permanent reductions in emissions can qualify for credit. Permanence can generally be assured by requiring changes in source permits to reflect a reduced level of permissible emissions.

4. *Quantifiable:* Emission reductions must be quantifiable in terms of both *measuring* the amount of the reduction

[1] Because this Policy Statement and accompanying Technical Issues Document reflect general Clean Air Act principles, states and individual sources are free to show that a general principle does not apply to particular circumstances or could be satisfied using approaches other than those described. States and sources have this option under current law, and nothing in this Policy Statement or the accompanying Technical Issues Document restricts their opportunity to make such showings.

and characterizing that reduction for future use. Quantification may be based on emission factors, stack tests, monitored values, operating rates and averaging times, process or production inputs, modeling, or other reasonable measurement practices. The same method of calculating emissions should generally be used to quantify emission levels before and after the reduction.

B. Using Emission Reduction Credits

ERCs may be used by sources in bubble, netting, or offset transactions. The general principles below will assure that all uses of ERCs are consistent with ambient attainment and maintenance considerations under the Clean Air Act.

1. *Emissions trades must involve the same criteria pollutant.* An emission reduction may only be traded against an increase in the same criteria pollutant. For example, only reductions of particulates can be substituted for increases of particulates, reductions of VOCs for increases in VOCs.

2. *All uses of ERCs must satisfy applicable ambient tests.* the Clean Air Act requires that all areas throughout the country attain and maintain national ambient air quality standards. The ambient effect of a trade depends on the dispersion characteristics of the pollutant involved. Ambient considerations will generally not affect trades involving VOC or NO_x, whose impacts occur across broad geographic areas. For these pollutants "pound for pound" trades may be treated as equal in ambient effect. However, dispersion characteristics are important for bubble and offset trades of SO_x, TSP, or CO whose ambient impact may vary with where the emission increases and decreases occur. Trades of these pollutants must demonstrate equivalent ambient impact under the three-tiered modeling screen discussed in the Technical Issues Document or under a similar approach.

3. *Trades should not increase hazardous pollutants.* Except as may be specifically permitted by future national emission standards for hazardous air pollutants (NESHAPs), a source may not use a bubble to meet NESHAPs requirements or increase emissions beyond the levels they prescribe. Where a significant fraction of a criteria pollutant stream has been listed under Section 112 but not yet regulated, the hazardous emissions involved in the trade should either remain equal or should decrease (i.e., be traded down).

4. *Emission trades cannot be used to meet applicable technology-based requirements.* New or expanding sources cannot use ERCs to meet new source performance standards, best available control technology requirements in PSD areas, or lowest achievable emission rate control technology requirements in nonattainment areas.

5. *States may allow bubbles in areas without approved demonstrations of attainment.* States are authorized to approve bubbles in such areas, so long as timely attainment of air quality standards will not be jeopardized. (See Section II.A above and the Technical Issues Document).

6. *Sources may use the bubble to achieve compliance.* States may allow sources to use a bubble to achieve rapid compliance once applicable emission limits and deadlines are established as part of a bubble application. States need not require sources to develop and go forward with detailed plans (including ordering equipment) to meet original emission limits when new limits which will supercede them are pending under a bubble application.

7. *States may extend certain compliance schedules.* States may give sources more time to implement bubbles by granting compliance extensions as part of approvals under generic rules, where (i) the area has received an attainment extension under Section 172(a)(2) of the Clean Air Act (applicable to VOC or CO); and (ii) the total amount of reductions required to satisfy the state's reasonable further progress demonstration will not be reduced for each year in question. States may grant similar compliance extensions for VOC or CO bubbles approved as individual SIP revisions subject to (i) above, provided the extension is consistent with reasonable further progress requirements (See section IV below).

8. *States may approve bubbles involving open dust sources of particulate emissions, based on modeling demonstrations.* This action reduces past restrictions on trades involving open dust sources of particulate emissions. Such trades may be approved based on acceptable modeling and/or monitoring demonstrations, provided sources agree to post-approval monitoring to determine if predicted air quality results have been realized.

C. Banking Emission Reduction Credits

Only emission reductions that are surplus, permanent, enforceable, and quantifiable can be banked. To provide maximum protection for sources and avoid future legal problems, state banking rules should specify the ownership rights established, the types of sources eligible to bank ERCs, and any additional conditions placed on certifying, holding, or using banked ERCs.

As a legal minimum, state banking rules must establish ownership rights which are consistent with Clean Air Act requirements, including the requirement that SIPs provide for attainment and maintenance of ambient air quality standards "as expeditiously as practicable." States have considerable latitude in meeting this requirement, and may guarantee banked ERCs against any ambient-based reduction in quantity, so long as that guarantee does not interfere with reasonable further progress and attainment should ambient standards change or additional emission reductions be required.

In most states banking will be an extension of ongoing permit activities. The state or its designee will accept and evaluate requests to certify an ERC, maintain a publicly available ERC registry or similar instrument describing the quantity and types of banked credits, and track transfers and withdrawals of ERCs.

III. State Generic Trading Rules

Use of emission reduction credits under state generic rules approved by EPA will not require individual SIP revisions. The Technical Issues Document explains acceptable generic rules and procedures which states may adopt to reduce the need for individual SIP revisions.

Emissions trades can be approved without SIP revisions if evaluated under EPA-approved state procedures that assure no trade will interfere with timely attainment and maintenance of ambient standards. State generic rules are approvable only if their procedures are sufficiently replicable in operation to meet this test. By approving the generic rule, EPA approves in advance an array of acceptable emission limits, and no further case-by-case federal approval is required for individual trades developed under the rule.

Any trade under a generic rule will involve emission increases at some sources and emission decreases at others. For trades to be approvable under a generic rule, the sum of these increases and decreases (i.e., applicable net baseline emissions) must be zero or less. States may adopt generic rules which exempt from individual SIP revisions: (1) *de minimis* trades whose sum of the emission increases, looking only at the increasing sources, totals less than 100 tons per year after applicable control requirements; (2) trades involving VOC or NO_x emissions (3) trades between SO_x sources, between CO sources, or between TSP

sources, provided those sources are located in the same immediate vicinity and emissions do not increase at the source with the lower effective plume height; and (4) other SO_2, CO or TSP trades which do not increase emissions and for which carefully defined use of a screening model predicts no significant increase in ambient concentrations. EPA encourages states to adopt such rules or develop alternative approaches that equally assure attainment and maintenance of ambient standards.

To the extent state procedures for rulemaking or permit changes do not assure reasonable public notice and opportunity for comment on proposed trades, states should incorporate such provisions as part of their generic rules.

IV. Trades Not Covered by Generic Rules

States and sources may continue to use the SIP revision process to implement trades which are not covered by a generic rule. Because the SIP revision process can take account of many more individual variations, trades which could not be accomplished under a generic rule may still be implemented as site-specific SIP revisions.

EPA will take action on generic rules and individual trades submitted as SIP revisions as quickly as possible after a state has adopted a SIP revision and submitted the action to EPA. EPA encouages "parallel processing" of such revisions, with EPA and the state conducting concurrent review so that both agencies can propose and take final action at roughly the same time. EPA will also publish noncontroversial SIP revisions as immediate final actions, converting them to proposals only if requests to submit comments are received within 30 days (see 46 FR 44477; Sept. 4. 1981).

V. Conclusion

This Policy Statement sets out basic principles for individual trades and approvable generic trading rules. EPA encourages states to use these principles as a framework and refer to the accompanying Technical Issues Document for further discussion and examples. States are encouraged to design other rules which satisfy these principles but meet their specific needs.

As a policy statement, this notice does not establish conclusively how EPA will resolve issues in individual cases. EPA will accept public comment on this proposal as well as on specific SIP changes submitted under it. and will review individually each generic rule and those emissions trades submitted as SIP revisions to determine their acceptability under the Clean Air Act. Interested parties will have full opportunity to scrutinize application of these general principles to specific cases, and to seek subsequent judicial review of such cases, when particular generic rules or individual trades are proposed and approved.

This Statement expands opportunities to use emissions trading. If implemented by states it can allow industry to use the bubble and other trading approaches in additional circumstances and geographic areas. The policy will also reduce adversary tensions, allow states to benefit from industrial knowledge, and encourage quicker compliance, while reducing unnecessary federal review. It represents important regulatory reform, for states as well as industry, by encouraging greater flexibility in meeting air quality goals.

Dated: April 2, 1982.

Anne M. Gorsuch,

Administrator.

Emissions Trading: Technical Issues Document

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Emissions Trading: Technical Issues Document

This Document offers more detail on technical issues for firms and pollution control agencies seeking to implement individual emission trades or generic trading rules that meet the principles in EPA's Emissions Trading Policy Statement.[1] It describes both the minimum legal requirements for emissions trades under the Clean Air Act. and a range of legal options which states [2] may consider. States and industry are encouraged to pursue other approaches consistent with those discussed here.

Emissions trading is voluntary. States may implement emissions trades on a case-by-case basis or develop generic trading rules covering one or more classes of transactions. Trades under approved generic rules will be exempt from individual SIP revisions. Such rules can also provide greater certainty by specifying which trades are quickly approvable.

Section I of this Document explains general legal principles governing all emissions trading. Section II explains principles governing state generic rules. Section III discusses special considerations for emission trades implemented as individual SIP revisions.

Because these sections reflect general Clean Air Act principles, states and individual sources remain free to show that a general principle does not apply to particular circumstances or can be satisfied using another approach. States and sources have this option under current law, and nothing in the Policy Statement or this Document restricts their opportunity to make such showings. (See Section III below).

[1] Emissions trading was formerly known as "controlled trading".

[2] "States" includes any entity properly delegated authority to administer relevant parts of a State Implementation Plan (SIP) under the Clean Air Act.

I. Components of Emissions Trading

The components of any emissions trade are the *creation* of an emission reduction credit (ERC), its *use* in a trade, and its possible *storage* in a bank.

A. Creating Emission Reduction Credits

States may grant credit only to those emission reductions that are *surplus, enforceable, permanent,* and *quantifiable.* Otherwise use of ERCs might degrade air quality, threaten the viability of the area's SIP, and result in more stringent controls.

1. *All Reductions Must Be Surplus.* Only surplus reductions not currently required by law can be substituted for required reduction as part of an emissions trade without jeopardizing air quality goals.

The first step in qualifying a reduction as "surplus" is to establish a level of baseline emissions. The baseline identifies the level of required emissions beyond which reductions must occur for a source to receive credit. It will generally be determined by whether the area is attainment or nonattainment, and by the way the state developed its SIP.

a. *Use of Actual or Allowable Emissions as the Baseline. In attainment areas* the baseline will generally be actual emissions—only reductions below a source's actual level of historical emissions can be considered surplus. Because current regulations specify actual air quality as the basis for determining increment consumption, these rules normally require that actual emissions be used for the area's maintenance strategy. (See 45 FR 52717; Aug. 7, 1980). However, allowable emissions may be used as the baseline if proper consideration is given to increment usage.

In *nonattainment areas* the baseline may be either maximum allowable emissions or actual historical emissions.[3] To determine which baseline is appropriate, the state should examine the assumptions used in developing its demonstration of attainment.

In *nonattainment areas which used allowable emissions as the basis for their attainment strategy,* sources can use their SIP allowable limits as the baseline for creating ERCs. Many states used allowable limits in developing their SO_2 and TSP attainment plans.

Other nonattainment areas used inventories that were either substantially deficient or based on actual emissions, or they relied on measured (and therefore "actual") ambient values as the primary basis for determining SIP emission limits needed to demonstrate attainment. Under current EPA regulations, in these areas some level of actual historical emissions would generally be the baseline. *However,* these areas may approve use of allowable emissions as the baseline on a case-by-case basis, where that use comports with reasonable further progress and the source shows it will neither create a new ambient violation nor prevent the planned removal of an existing violation. (See Section III)

b. *Surplus Reductions in Areas Lacking Approved Demonstrations.* In several jurisdictions demonstrations of attainment are not yet complete. Some of these jurisdictions are uncertain where to secure sufficient emission reductions; others have not yet adopted enforceable emission limits based on reasonably available control technology (RACT) for specific industrial processes. Additional emission controls on these or other sources generally are needed to reach attainment. The question is how "surplus" should be defined for sources lacking SIP-defined RACT emission limits in these areas. Where RACT is already defined in the SIP, it will of course be the baseline. Where RACT for relevant source categories has not been defined, credit for surplus reductions may be granted in at least two general ways which are consistent with Clean Air Act requirements for reasonable further progress and attainment.

(i) *Use of a RACT Baseline.* If RACT has not been defined in the SIP, the source may agree with the State and EPA to an acceptable RACT limit for the emission sources involved in the trade. A surplus would then consist of any emission reductions in excess of those required to meet RACT. Where sources voluntarily agree to such a RACT level, EPA encourages states not to reexamine the agreed-upon individual emission levels for a period of time consistent with the statutory deadlines for attainment, unless there is no other practical way to satisfy requirements of the Clean Air Act.

A RACT baseline is the only option in areas that will not attain the relevant primary ambient standard by December 1982 and have not received attainment extensions for such standard. Because of the extremely short time period remaining for attainment and the practical difficulty of securing further reductions prior to the December 1982 deadline, this limitation is necessary to assure that trades in these areas comport with the statutory deadline and the mandate for RACT "as expeditiously as practicable."

(ii) *Use of Actual Emissions Baseline.* Areas that will not attain the primary ozone or CO ambient standard by December 1982, but have received attainment extensions until 1987, as well as areas with plans that will attain the primary (but not the secondary) TSP or SO_2 ambient standard by December 1982, may use current actual emissions (or "old" Section 110 SIP limits if applicable) as the baseline. Under this option, sources in these areas could trade using individual emission sources not yet subject to RACT limits, so long as states clearly advise sources of their responsibility to find or produce reductions equivalent to future RACT requirements if and when the state imposes them and sources commit to meet these future requirements. This would give industry flexibility to create and use ERCs at the earliest date. It would also avoid having to negotiate individual RACT baselines through case-by-case SIP revisions.

States that choose not to rquire negotiated RACT baselines should be aware that their SIPs must still comply with Section 172(b)(2), which requires imposition of RACT "as expeditiously as practicable."

C. *No Double-Counting of Reductions.* To be considered surplus, an emission reduction cannot already have been included as part of the area's baseline emissions. Double-counting of reductions—granting credit for the same emission reduction, once to the state and a second time to a source for use in an emissions trade—must be addressed in the following situations.

(i) *Crediting Pre-Existing Emission Reductions.* In *nonattainment areas* credit generally cannot be granted for emission reductions made before monitoring data was collected for use in SIP planning. Because monitored ambient levels may have *already* reflected these emission decreases, they would have been assumed in calculating the reductions needed to attain ambient standards. States should clearly identify in their rules the date before which reductions will not qualify for credit. The earliest acceptable baseline date would normally be the year of the most recent emission inventory or monitoring data used in planning Part D SIP revisions under the Clean Air Act Amendments of 1977.

In *attainment areas* emission reductions that occurred before the PSD emissions baseline was established generally cannot qualify for credit. States have already assumed these reductions in their PSD baselines. If

[3] See, 46 FR 52723 (Aug. 7, 1980). Several aspects of EPA's August 7th regulations, including the definition of baseline, are currently under judicial review. Any rulemaking changes which result from that litigation may be controlling here.

credited and later used, they could undermine the area's strategy to maintain air quality.

(ii) *Crediting Reductions From Shutdowns.* In general, a state may credit reductions from shutdowns for *bubble trades* if the SIP has not already assumed credit for these reductions in its attainment strategy. So long as reductions from shutdowns have not already been counted in developing an area's attainment strategy, they are an appropriate source of surplus reductions for bubble trades.

Many SIPs assumed a set quantity of reductions from new plant openings and existing plants shutdowns. These SIPs incorporated into their attainment strategy a net "turnover" reduction in emissions because new sources are generally cleaner than those that shut down. Double-counting would occur if a specific source received credit for reductions from such a shutdown, since that reduction was already assumed in the SIP's demonstration of attainment.

States have at least three options to grant sources credit without this kind of double-counting. *First,* they may re-examine any "turnover" credits in their SIP and decide not to take credit for these reductions. *Alternatively,* they may allow credit only after the total quantity of shutdown reductions assumed in the SIP has occurred. *Finally,* they may allow credit for a percentage of the total emission reductions realized from a shutdown, if they can show that such credit is consistent with the SIP's demonstration of attainment and reasonable further progress.

d. *Multiple Use of ERCs.* Once surplus reductions are credited, states should guard against their multiple use. In general, the same ERCs must not be banked by two different entities or used to satisfy two different regulatory requirements at the same time. To prevent these results, states should adopt an ERC registry or equivalent means of accounting for the creation, banking, transfer, or use of all ERCs. (See Section I.C.5)

e. *Reductions from Uninventoried Sources.* Sources not included in an area's SIP emission inventory may apply for credit. In general, so long as granting credit for reductions from these sources will not jeopardize an area's demonstration of attainment or reasonable further progress, there are no legal restrictions on such credits.

In *attainment areas* all sources, regardless of whether they have been included in an inventory, may create ERCs using actual emissions as the baseline. Those emissions need only have been included in the area's PSD baseline.

In *nonattainment areas,* whether sources not on the inventory can create ERCs will turn on how the SIP's demonstration of attainment was designed.

Some areas first monitored ambient values to determine required SIP reductions, then required a proportionate reduction in emissions from certain source categories in order to attain. These areas may grant credit for reductions from uninventoried sources in at least three ways. *First,* they could required the source to use a RACT baseline and grant credit only for reductions below that baseline. *Alternatively,* they could require the same percentage reductions as imposed on inventoried sources, and grant credit only for reductions in excess of that amount. *Finally,* where no demonstration of attainment exists, they may use either a negotiated RACT baseline or (in appropriate circumstances) an actual emissions baseline. (See Section I.A.1.B above)

Other areas developed SIP demostrations based on ambient air quality models rather than area-wide proportionate reductions. To the extent these DIPs demonstrated ambient attainment through reductions required from inventoried sources, reductions from sources not on the inventory can be credited using actual emissions as the baseline.

2. *Alternative Emission Limits Must Be Enforceable. Each bubble, netting, offset or banking transaction must be enforceable and must approved by the state. Under current EPA regulations reductions used in bubble, offset and netting trades must be federally enforceable.*[4] This requirement for enforceability can generally be satisfied either through existing procedures (including individual SIP revisions or state permits issued under 40 CFR 51.18) or through generic rules, since any enforceable compliance instrument imposing emission limits within the scope of a generic rule is deemed part of the SIP.

Emission limits established by a trade maust also be incorporated in a compliance instrument which is legally binding and practicably enforceable. *Trades involving individual SIP revisions* automatically satisfy this requirement.

For *trades under generic rules,* a compliance instrument could take the form of an agreement between the source and state, and operating or preconstruction permit, or a consent decree. Many State permits and permit procedures may need revisions to assure that they provide adequate compliance information. However, such revisions need only occur on a case-by-case basis as individual trades are approved.

Compliance instruments should assure that enforcement officials do not have to test simultaneously every emission source involved in a trade. This generally means source-specific emission limits. However, states may use an overall emission limit that applies to a group of emission sources which can be monitored sumultaneously. This will generally require a reliable method of determining compliance through production records, input factors, or similar indirect means. (See 45 FR 80824; Dec. 8, 1980)

The compliance instrument should also specify applicable restrictions on hours of operation, production rates or input rates; enforceable test methods for determining compliance; and necessary recordkeeping or reporting requirements. To be enforceable, these limits must state the minimum time period over which they will be averaged (e.g., lbs/hour, lbs/MMBtu averaged over 24 hours, production rate/day).

3. *All Emission Reductions Must Be Permanent.* An emission reduction credit must be a permanent reduction in the level of pollution emitted by a source. Use of an ERC which is not permanent could adversely affect air quality by allowing increased emission from both the source creating the ERC and the source where it is used.[5]

To receive credit for reductions in operations (e.g., a reduction from 3 to 2 workshifts), a source must have its permit or other compliance instruction altered to reflect the curtailment in production. Future increases in production beyond the permit amount would generally require compensating emission reductions.

[4] In July 1981 EPA administratively stayed certain rules relating to federal enforceability requirements for netting and offsets. 46 FR 38695 (July 15, 1981). This stay has expired and has not been removed. Requirements of existing regulations accordingly remain applicable.

[5] As an alternative, states may allow trades whose emissions increases and emissions decreases are equal in duration rather than strictly permanent. This is the minimum legal requirement under the Clean Air Act, but may require states to track trades over time to assure ambient equivalence.

Permanence may present special but resolvable problems for reductions from small sources not subject to permits, offset requirements, or production constraints. States which grant credit from these source categories should address the possibility that reductions from one source may be followed by equal or greater increases from similar sources in adjacent areas.

4. *All Reductions Must Be Quantifiable.* Before an emission reduction can be credited it must be quantified. This generally means the state must establish a reliable basis for *Measuring the amount and rate* of the reduction and *describing its characteristics.*

a. *Measuring the Reduction.* To quantify ERCs, emissions must be calculated both before and after the reduction. Although many different methods of calculation are available (e.g., emission factors, stack tests, monitored values, production or process inputs), the same method and averaging time should generally be used to quantify emissions before and after the reduction.

b. *Describing the Reduction.* If an ERC is to be used at the time of creation, only characteristics necessary to evaluate that proposed use need be described. Where the ERC is to be banked and its eventual use is not yet known, a more detailed description is advisable.

B. Using Emission Reduction Credits

This section explains the substantive and procedural principles applicable to use of ERCs in bubble, netting or offset transactions.

1. *Substantive Principles for Using ERCs.*

a. *Emissions Trades Must Involve the Same Pollutant.* The Clean Air Act requires states to develop separate plans to attain and maintain the national ambient air quality standard for *each* criteria pollutant. Thus, all individual bubble, netting or offset cases must involve the same pollutant. Only reductions of particulates can substitute for increases of particulates, reductions of SO_2 for increases in SO_2, etc.

b. *All Uses of ERCs Must Satisfy Ambient Tests.* The Clean Air Act requires that all areas throughout the country attain and maintain ambient standards. In *nonattainment areas*, use of ERCs cannot create a new violation of an ambient standard or prevent the planned removal of an existing violation. In *attainment areas*, use of ERCs cannot violate an increment or ambient standard. The ambient effect of a trade generally depends on the dispersion characteristics of the pollutant involved.

VOC or NO_x Trades. Ambient considerations will not affect trades involving VOC or NO_x, whose impacts occur across broad geographic areas. Within such areas one ton of decreased emissions is generally equivalent in ambient effect to one ton of increased emissions, since the precise location of those increases and decreases ordinarily does not matter. For these pollutants, "pound for pound" trades may be treated as equal in ambient effect.

TSP, SO_2 or CO Trades. Ambient considerations are critical for trades involving SO_2, particulates, or carbon monoxide, whose air quality impact may vary with where the emission increases and decreases occur. One hundred tons of ERCs for these pollutants created at one site may balance the ambient impact of a 100-ton increase at a site nearby, but may only balance the effect of an 80-ton increase at a site further away. In addition to distance between sources, plume parameters, pollutant characteristics, meterology, and topography will also affect the ambient impact of such a trade.

As a general principle, bubble applications must demonstrate ambient "equivalence" and offset transactions must demonstrate ambient progress. Such demonstrations have typically been made through mathematical dispersion modeling which predicts the ambient impact of various emissions.

This Document authorizes use of a three-tiered screen with the degree of required modeling linked to the likely ambient impact of the proposed trade. The following sections describe use of this modeling screen to approve many trades without full-scale ambient modeling. Use of this modeling screen to define the scope of generic rules is discussed in Section II below.

(i) *Level I:* In general no modeling is needed if the proposed TSP, SO_2 or CO trade does not result in a net increase in applicable baseline emissions, the relevant emission sources are located in the same immediate vicinity, and no increase in emissions occurs at the source with the lower effective plume height. In such cases it can reasonably be assumed that "pound-for-pound" trades will produce ambient effects equivalent to what current modeling would predict, and modeling is not required.

(ii) *Level II:* Only limited modeling involving the specific emission sources in the trade is needed for trades not included in Level I, if there is no net increase in applicable baseline emissions and if emissions after the trade will not cause a significant air quality impact at the receptor of maximum predicted impact. In determining "significant" impact, states may use the significance levels established by EPA for determining when air quality monitoring is necessary for PSD cases: 10 $\mu g/m^3$ for the 24-hour standard for TSP; 13 $\mu g/m^3$ (24-hr) for SO_2; and 575 $\mu g/m^3$ (8-hr) for CO. (*See*, 45 FR 52709, Aug. 7, 1980). These levels appropriately identify trades whose potential ambient impact need not be further evaluated before approval.

(iii) *Level III:* Full dispersion modeling, considering all sources in the area of impact, is required if net applicable baseline emissions will increase as a result of the trade *or* if the trade will have a significant impact on air quality at the receptor showing maximum ambient impact.

This modeling screen will ensure that the air quality impact of trades is equivalent to the impact of the original SIP limits.

c. *Trades Should Not Increase Net Baseline Emissions in Nonattainment Areas.* Congress required *nonattainment areas* to demonstrate reasonable further progress (RFP) by reducing emissions each year in amounts sufficient to attain ambient standards by statutory deadlines. In general, RFP is measured by an areawide quantity of reduced emissions.

Trades in such areas which increase total emissions can generally occur only as individual SIP revisions in which the state either demonstrates that the trade is consistent with RFP or revises RFP as part of the proposed SIP revision. EPA will approve such revisions as amendments to the SIP, provided they comport with ambient air quality standards and reasonable further progress.

However, such trades may occur under generic rules where existing sources were required to reduce emissions beyond the amount required to bring the area into attainment. In such cases a growth margin was created which may be used at the discretion of the state to compensate for any increases in emissions without violating reasonable further progress requirements.

In attainment areas trades increasing total emissions could generally be permitted, but may consume some or all of the increment, trigger PSD review, or both.

d. *Emissions Trades Should Not Increase Hazardous Pollutants.* Under the Clean Air Act all sources must meet applicable Section 112 (NESHAPs) regulations for hazardous air pollutants. Except as may be specifically permitted in future Section 112 regulations, a source may neither use a bubble to meet these requirements, nor increase emissions beyond the levels they prescribe.

Where pollutants have been listed under Section 112, but are not yet subject to specific regulations, states may allow trades consisting of equivalent increases and decreases of the same listed pollutant at reasonably

close emission points. States may also approve trades in which reductions in hazardous emissions compensate for increases in non-hazardous emissions. For example, a source may trade benzene for any non-hazardous VOC, if the benzene emissions are decreased (i.e., "traded down").

e. *Emissions Trades Cannot Be Used to Meet Technology-Based Requirements.* The Clean Air Act specifically requires new or expanding sources to meet technology-based new source performance standards (NSPS), regardless of the attainment status of the area in which they are located. This requirement prohibits use of bubbles to meet or avoid NSPS, and has been interpreted to bar use of such a bubble to meet new source review requirements for best available control technology (BACT) in PSD areas, or lowest achievable emission rate control technology (LAER) in nonattainment areas. Thus, new emissions sources subject to new source review cannot use ERCs from existing sources to satisfy these requirements.

Expanding or modernizing sources can, however, use *internal* emission reductions from within the same plant to "net out" of new source review. Such sources still must meet NSPS, but are not subject to BACT in attainment areas (45 FR 52676; Aug. 7, 1980) or LAER in nonattainment areas (46 FR 50766; Oct. 14, 1981), since they are not considered new sources under Parts C and D of the Clean Air Act.

f. *Trades Involving Open Dust Emissions.* Trades involving open dust sources of particulate emissions may be approved based on modelled demonstrations of ambient equivalence. Sources proposing such trades should be required to undertake a post-approval monitoring program to evaluate the impact of their control efforts. If the results of monitoring indicate that initial open dust controls do not produce the predicted air quality impact, further enforceable reductions may be required. States must either require sources to acknowledge their responsibility for further reductions, or deem trading applications to be such an acknowledgment, as a condition of approval.

2. *Procedural Steps for Using ERCS.* Emission trades may be implemented through individual SIP revisions or state generic rules. This section describes principles applicable to either procedure. General principles for generic rules are discussed in Section II below. Special considerations for trades which still require individual SIP revisions are discussed in Section III.

a. *Bubbles Can Be Used to Achieve Compliance.* The bubble policy required that sources be subject to binding compliance schedules based on original SIP emission limits before being eligible to apply for bubbles. This requirement threatened sources with tight milestones for the purchase of conventional control equipment and tended to discourage both rapid compliance and flexibility. Under today's Policy Statement states may promote rapid compliance by allowing sources to agree to emission limits established as part of their bubble application, instead of requiring sources to agree to compliance plans based on their original SIP limits before an application can be filed.

b. *Extensions of Compliance Deadlines.* States may extend compliance deadlines for VOC or CO sources on a case-by-case basis as part of bubble approvals. The Clean Air Act limits such extensions to sources which are located in areas that have received VOC or CO attainment extensions until 1987, and whose bubble will be consistent with reasonable further progress requirements. Because this will usually require a revision of the state's reasonable further progress demonstration, such extensions must generally be submitted as SIP revisions.

However, states may also grant compliance extensions without case-by-case SIP revisions as part of bubble approvals under a generic rule. The rule should provide that: (1) Extensions may only be granted in areas which have received attainment extensions to 1987; and (2) the total amount of reductions claimed in the state's approved RFP demonstration will not be reduced for each year in question. For example, if a source wishes to defer 100 tons per year of reductions from 1982 to 1985, then as part of the bubble approval, the state must show that an additional 100 tons per year of reductions has already occurred in 1982, or that provisions for such additional reductions already exist.

c. *Pending Enforcement Actions.* A bubble cannot be approved for an individual emission source which is presently the subject of a federal enforcement action or outstanding enforcement order unless EPA (and where necessary the appropriate court) approves the proposal and the compliance schedule it contains. This applies to civil actions filed under Clean Air Act Section 113(b), criminal actions filed under Section 113(c), a notice imposing noncompliance penalties issued under Section 120, administrative orders issued under Section 113(a), or a citizen suit filed under Section 304 where EPA has intervened.

This requirement need not preclude bubble approvals under generic rules, provided an appropriate mechanism for securing and recording EPA approval is used. Sources should, however, be aware that such approvals cannot be finally effective until approved by the appropriate court.

C. Banking Emission Reduction Credits

State SIP rules may include a banking provision which addresses ownership and holding of ERCs over time. Without such a provision, firms risk losing surplus reductions should a major SIP revision or new set of control requirements be instituted. Generic banking rules can afford such ERCs substantial protection consistent with the Act's mandate to attain and maintain ambient standards.

The bank can accept and evaluate requests to certify an ERC, serve as a clearinghouse for credits on deposit, and account for transfers and withdrawals of ERCs. These roles will generally be performed by the state as part of its normal permitting activities.

The following sections address both minimum legal requirements for state banking rules and issues states should consider. States may adopt other approaches which produce equivalent results.

1. *Banking Rules Must Designate an Administering Agency.* Banking rules must identify the entity responsible for specific functions. While the state will ordinarily be responsible for verifying and processing ERC requests, all or part of this responsibility may be delegated to other organizations. Such organization(s) must possess the resources and legal authority to implement delegated activities.

2. *Only ERCs May be Banked.* Banked emission reductions must be *surplus, permanent, quantifiable* and *enforceable.* This generally means that such reductions must be made at the time they are deposited in the bank as ERCs. *However,* if a firm commits to produce a specific reduction in the future, a state may allow a conditional deposit to be made. In all cases the reduction must actually be achieved before it can be used in an emissions trade.

3. *Procedures for Banking ERCs Should be Defined.* To speed approval of trades and provide greater certainty for potential ERC creators and users, state banking rules should clearly identify which proposed emission reductions can qualify to be credited and banked, the information required of sources to substantiate their claim for credit, and any required application forms.

4. *Banking Rules Must Establish Ownership Rights.* To prevent two entities from claiming the same ERCs, state banking rules must specify who can own ERCs. For example, while the source creating the ERC will generally be its owner, the state could, as part of its rule, reserve ownership of certain classes of ERCs to itself or local governments.

5. *Banking Rules Must Establish an ERC Registry or Its Equivalent.* An ERC registry or equivalent instrument lets states track ownership, use, and transfer of all banked ERCs. Banking rules must provide that no transfer of title to a banked ERC will take effect until the transaction is reflected in the registry. This tracking system is important to minimize disputes over ownership and provide a central list of certified ERCs which may be available. It can also provide useful information for quickly evaluating any proposed use of a banked ERC.

Information which may help evaluate proposed use of a banked ERC should be recorded at the time of its creation and entered as part of its banking record. This information should include the location of the source creating the ERCs, its stack parameters, the temperature and velocity of its plume, particle size, the existence of any hazardous pollutants, daily and seasonal emission rates, and any other data which might reasonably be necessary to evaluate future use.

To perform these tracking and clearinghouse functions the ERC registry must be accessible to the public. Subject to confidentiality considerations, states should make copies of the ERC registry available at convenient locations and times, and may want to publish a periodic summary of banked ERCs.

6. *Possible Adjustments to ERCs Based on Enforcement Considerations.* To avoid legal problems, banking rules should clearly state what, if any, changes may occur to ERCs after they have been banked. Once an ERC has been used by another source to meet a permit requirement, any violation of the conditions under which that ERC was created should result in enforcement against the source *producing* that emission reduction and not the source *using* the ERCs. If a state attempted to enforce against the source using purchased ERCs, a complex set of third-party lawsuits would ensue. This would likely discourage sources from purchasing ERCs in the Future.

7. *Possible Adjustments to ERCs Based on Ambient Attainment Considerations.* To assure the validity of its demonstration(s) of attainment, a state with a banking rule should assume that all banked emissions will ultimately be used. Thus, in evaluating their ability to attain national standards, states should add to their inventory or measured ambient value, all unused banked reductions at the site at which they were created.

Additional emission reductions may be required from sources because of their area's failure to attain ambient standards, because of an increment violation, or because new RACT requirements are being imposed under a SIP schedule. The existence of banked ERCs must not interfere with states' ability to obtain these additional reductions. For this reason state banking rules should specifically address how ERCs will be treated if additional reductions are required. Available options include:

a. *ERCs Are Absolutely Guaranteed Against Adjustment.* The state would determine the required quantity of reductions and assess necessary controls on the inventory. Sources with banked ERCs would not be exempt from any requirement for additional reductions, but could satisfy that requirement by using their banked ERCs, by reducing emissions elsewhere, or by purchasing equivalent ERCs.

To effectively implement this option, it would be particularly important to state new control requirements in terms of "RACT-equivalent" reductions.

b. *Current ERCs Are Fully Preserved,* but either their use *or* future ERC deposits are suspended until the SIP has committed to secure reductions sufficient to reestablish reasonable further progress or cure an increment violation. Use of either type moratorium would be consistent with air quality objectives while allowing sources to retain or use their entire quantity of banked ERCs. However, this option may be undesirable because of uncertainty regarding the moratorium's start, duration, or potential interference with user planning.

c. *Across-the-Board Discounting.* Under this option, all ERCs in the bank would be discounted by the same factor. For example, if a 10% additional reduction is required from a category of sources for the SIP's new demonstration of attainment, the state would discount all banked ERCs from those types of sources by 10%. Although the quantity of ERCs held by a firm will be reduced, the overall supply of ERCs will decrease, while demand will increase. Therefore, the overall value of remaining ERCs is likely, at minimum, to remain the same. Indeed, other sources may purchase banked ERCs to meet the 10% reductions required of them.

This option is relatively straightforward for VOC or NO_x. For SO_2 or TSP more detailed, source-specific modeling would generally be required to allocate the discount necessary to demonstrate attainment.

States may adopt any of these methods of accommodating possible additional reductions. They may also adopt any equivalent method which achieves the same objectives.

II. Trades Covered by State Generic Rules

This section explains expanded opportunities for states to develop generic rules under which certain classes of emissions trades will be exempt from individual SIP revision.

A. General Principles for Evaluating Generic Rules

A generic rule is approvable if it assures that (1) applicable net baseline emissions will not increase; (2) emissions trades otherwise requiring SIP revisions under §§ 110(i) and 110(a)(3) of the Clean Air Act will be evaluated under procedures that are sufficiently replicable in operation; and (3) emission limits produced under the rule will not interfere with ambient attainment and maintenance. Replicability generally means that specific modeling procedures are prescribed and that states have appropriately defined their choice of models, model inputs, and modeling techniques in applying these procedures to specific trades. Thus, these trades should not create new ambient violations or interfere with the planned removal of existing violations. By approving such generic rules EPA approves in advance an array of acceptable SIP emission limits, and no further case-by-case EPA approval is required.[6]

B. Scope of Generic Rules

States may use a range of mechanisms to exempt trades from EPA review as individual SIP revisions. While several mechanisms are explained below, states may submit other generic rules that satisfy these basic principles.

1. *De Minimis Trades.* Trades in which net baseline emissions do not increase and in which the sum of the emission increases, looking only at the increasing sources, totals less than 100 tons per year after applicable control requirements, may proceed without a

[6] Replicability more generally means a high likelihood that two decision-makers applying the rule to a given trade would reach the same conclusion. For one example of a generic rule incorporating a very simple formula that meets the test of replicability, see 46 FR 20551 (Apr. 6, 1981).

SIP revision. Such trades will have at most a *de minimis* impact on local air quality because only minor quantities of emissions are involved. Moreover, because only trades which produce no net increase in emissions can be exempt, overall air quality will not suffer. The Federal resources required to evaluate these trades could best be used to evaluate actions that have a potential impact on air Quality.[7]

2. *VOC or NO_x* Trades. All VOC or NO_x trades under a generic rule that assures no net increase in applicable baseline emissions may occur without individual SIP revisions.

The ambient impacts of VOC and NO_x emissions are area-wide rather than source-specific. All such emissions within a broad area are considered comparable, regardless of plume height, topography or related factors. Thus, the ambient impact of trades involving VOC or NO_x will by definition be equivalent to that of the sum of the SIP emission limits for the emission sources involved in the trade. As long as the sum of these emission limits is not exceeded, the limits for each specific emission source can be reallocated without adversely affecting air quality. This essentially arithmetical task is so mechanical that VOC or NO_x trades developed in this manner cannot reasonably interfere with ambient attainment and maintenance.

3. *SO_2* CO, or TSP Trades. For trades involving SO_2 CO, or TSP it is more difficult, but by no means impractical, to develop a generic rule which assures that valid ERC uses cannot reasonably interfere with attainment and maintenance.

The ambient impact of these pollutants depends on site-specific factors such as topography and plume height which are ordinarily evaluated by ambient modeling. However, if the emission sources are located in the same immediate vicinity and emissions decrease at the source with the lower effective plume height, therefore minimizing localized ambient impact, equal increases and decreases in emissions from these sources will ordinarily produce equivalent ambient effects (See Level I of the Modeling Screen). As a result, trades involving emission sources within Level I may be treated in the same manner as trades involving VOC or NO_x and may be exempted from individual SIP revisions.

EPA will normally approve generic rules that define "same immediate vicinity" as up to 250 meters between the individual emission sources involved in a trade. *However*, where such trades involve areas with complex terrain, some modeling might still be required to assure that ambient impact is properly considered. Generic rules should specify criteria for identifying such circumstances and for defining what modeling will be required.

4. *Other Mechanisms for Exempting TSP, SO_2 or CO Trades from Individual SIP Revisions.* Other TSP, SO_2 or CO trades can be exempted from individual SIP revisions if they occur under state generic rules which satisfy the replicability and air quality requirements stated above.

Possible generic approaches include:

(a) Developing SIP rules which allow identified sources to meet an array of specific emission limits consistent with ambient attainment and maintenance. For example, states could approve a modeled formula for two or more specific emisson sources which would both satisfy ambient concerns and let firms determine particular permit limits at each emission source. This formula would have to be adopted as part of the SIP.[8]

(b) Developing criteria for use of simplified Level II modeling (see section I.B.1.b, above) for specified trades. This approach would exempt trades which (1) produce no net increase in applicable baseline emissions, (2) can routinely be modeled in a predescribed manner, and (3) will not have significant ambient impact. The generic rule must specify either the particular model that will be employed in a given situation, or criteria for selecting models in specified circumstances. To limit variability in modeling results the rule must also specify procedures for selecting input data (e.g., wind speed, stability class, source emission rate) which are sufficiently definite to meet the test of replicability. To determine whether a trade will have significant ambient impact these procedures should assess whether the change in emissions after the trade from the increasing source has the potential to cause an increase of more than 10 $\mu g/m^3$ over at 24-hour period for TSP, 13 $\mu g/m^3$ (24 hours) for SO_2, or 575 $\mu g/m^3$ (8 hours) for CO at the receptor of maximum predicted impact.

C Applicability of Generic Rules To Process Fugitive and Open Dust Emissions Trades

Trade involving *process fugitive emissions of VOC or NO_x* may routinely be approved under generic rules. However, because of their dispersion characteristics, it is more difficult to define generic rules that can be applied in a sufficiently replicable fashion to trades involving process fugitive or open dust TSP emissions.

In general *TSP trades involving process fugitive emissions* can be approved under generic rules if: (1) process fugitive emissions are traded against similar sources of process fugitive emissions, or (2) emissions from point sources are traded against process fugitive emissions which can reasonably be represented by a point-source dispersion pattern. This means that relevant parameters such as emission release height must be readily determinable. Unless such trades fall within Level I of the modeling screen or are *de minimis*, only processes whose fugitive emissions can be adequately represented by the dispersion model(s) specified in an approved generic rule can be included in a trade under that rule.

For *TSP trades involving open dust emissions* states should be aware that approvable generic rules which appropriately limit the choice of screening models and relevant inputs (including acceptable emission factors) will currently be difficult to formulate. Accordingly, open dust trades generally will have to be submitted as individual SIP revisions.

D. Enforcing Emission Limits Under Generic Rules

Alternative emission limits approved under generic rules are considered by EPA to be federally enforceable. Generic rules should specify that such alternative limits become applicable requirements of the SIP for purposes of §§ 113 and 304 of the Clean Air Act and are enforceable in the same manner as other SIP requirements. To assure that EPA and citizens know what emission limits apply, generic rules should also specify that EPA be informed of applicable emission limits before and after the trade, following approval of the trade by the state.

E. EPA Oversight of Trades of Under Generic Rules

The Clean Air Act requires EPA to monitor administration of SIPs, including generic rules. *See* § 110(a)(2)(H). EPA will audit the information supplied for each trade and

[7] Although states may exempt *de minimis* trades from federal SIP revisions, these trades are still subject to ambient tests. They should accordingly be evaluated by the state under the modeling screen (See Section I.B.1.b. above) or an equivalent approach.

[8] For example, the emission limits for the four stacks at the stuart Power Plant in Adams County, Ohio are 3.16 pounds of SO_2 per million BTU at each stack, or at the plant's choice (after notification to EPA), any limit in pounds per BTU which satisfies the following equation: 0.0791 (EL_1+EL_2+EL_3+EL_4<1. See 40 CFR 5.1881(11).

may request additional relevant information. Should EPA determine that approved trades are substantially inconsistent with generic rules in the SIP, it will notify the state and specify any necessary remedial measures.[9]

F. Public Comment

For trades occuring under generic rules, existing state statutes or regulations will generally provide reasonably adequate notice and comment opportunities. If these opportunities are not provided generic rules should explicitly address this issue.

To ensure public awareness consistent with § 304 of the Clean Air Act, states should also, at a minimum, publish any changes to emission limits which result from trades approved under a generic rule (see 46 FR 20554; April 6, 1981).

III. Trades Not Covered by State Generic Rules

In the absence of a generic rule, states and sources may continue to use SIP revisions to effect bubble or external offset trades. Individual trades may also fall outside the scope of an approved generic rule and still be implemented as individual SIP revisions. The principles described in the Policy Statement and this Document will generally be used to evaluate these emission trades.

Because of the ability of the SIP revision process to take account of individual variations, many trades which could not be accomplished under a generic rule may be acceptable use individual SIP revisions. For example, proposed bubles which produce a net increase in baseline emissions could nevertheless be approved through a SIP revision showing that requirements for attainment and maintenance were satisfied. In submitting such a bubble application, the state would have to revise its reasonable further progress demonstration to account for the increase in emissions and EPA would review the proposal to determine if the demonstration of attainment and RFP were satisfactor. Without such a SIP revision, trades increasing net baseline emissions would generally be acceptable only if compensating additional controls were already required in the SIP.

Through the SIP revision process, states and sources may also demonstrate that a general principle discussed in Section I above does not apply to their particular circumstances, or that such a principle may be satisfied in other ways. For example, they may show that a RACT baseline is unnecessary for a particular source because resulting reductions are not needed for attainment; that despite general requirements for use of an actual emissions baseline, an allowable baseline is acceptable in a particular situation based on air quality modeling; or that reductions from specific shutdowns or uninventoried sources can be fully credited without interfering with reasonable further progress and attainment.

EPA will make reasonable efforts to take prompt action on SIP trading proposals after a state has ruled on an individual application and submitted it to the Agency. EPA will encourage "parallel processing" of proposals, with EPA and state officials conducting concurrent review so that both agencies can give public notice of proposed action at roughly the same time. EPA can then take prompt final action after the state completes its proceedings, provided the state does not substantially alter the proposal after public notice. EPA will also publish non-controversial SIP revisions as immediate final actions, converting them to proposals only if adverse comments are received within 30 days (see generally 46 FR 44477; Sept. 4, 1981).

Appendix.—Regional EPA Emissions Trading Coordinators

Region I: Marcia Spink, Stationary Source Section, Air Programs Branch, John F. Kennedy Federal Building, Boston, Massachusetts 02203, (617) 223-4448; FTS 223-4448

Region II: Linda Comerci, Permits Administration Branch, Planning and Management Division, 26 Federal Plaza, New York, New York 10007, (212) 264-4333; FTS 264-4333

Region III: David Arnold, Air Programs Branch, 6th and Walnut Streets, Philadelphia, Pennsylvania 19102, (215) 597-7936; FTS 597-7936

Region IV: Archie Lee, Air Programs Branch, 345 Courtland Street, N.E., Atlanta, Georgia 30308, (404) 257-3286; FTS 257-3286

Region V: Dick Dalton, Mary Ryan, Air Programs Branch, 230 South Dearborn Street, Chicago, Illinois 60604, (312) 886-6053; FTS 886-6053

Region VI: Michael Mendias, Air Programs Branch, First International Building, 1201 Elm Street, Dallas, Texas 75270, (214) 767-2734; FTS 729-2734

Region VII: Charles Whitmore, Air Support Branch, 324 East 11th Street, Kansas City, Missouri 64106, (816) 374-6525; FTS 758-6525

Region VIII: Dale Wells, Air Programs Branch, 1860 Lincoln Street, Denver, Colorado 80295, (303) 837-3763; FTS 327-3763

Region IX: Wally Woo, Air and Hazardous Materials Section, 215 Freemont Street, San Francisco, California 94105, (415) 974-8210; FTS 454-8210

Region X: Dave Bray, Air Programs Branch, 1200 6th Avenue, Seattle, Washington 98101, (206) 442-1352; FTS 399-1352

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[9] A trade which does not meet the requirements of a generic SIP rule is not part of an SIP and by defintion cannot replace prior value emission limits in the SIP. (See 46 FR 20554-5; April 6, 1981). In these cases EPA must reserve the right to take remedial action to assure attainment and maintenance, including as a last resort enforcement of the original SIP limits.

ENVIRONMENTAL PROTECTION AGENCY

Control Techniques Guidelines; Density Adjustment for Dibasic Ester Coating Solvent

[AD-FRL-2287-3]

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: E. I. du Pont de Nemours and Company (Du Pont) has petitioned that the EPA allow States to permit a density adjustment for dibasic ester (DBE) coating solvent when determining compliance with State regulations for volatile organic compound (VOC) emissions from surface coating operations. On June 18, 1982, the EPA published a notice in the Federal Register (47 FR 26452) which stated that the Agency would approve Du Pont's petition unless comments giving sufficient reasons to deny it were received. Based upon the comments submitted, the EPA is denying Du Pont's petition.

ADDRESS: Docket No. A-82-25, containing material relevant to Du Pont's petition is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at the EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. James C. Berry, Chemicals and Petroleum Branch, Emission Standards and Engineering Division (MD-13), U.S Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number (919) 541-5605.

SUPPLEMENTARY INFORMATION: DBE coating solvent is a mixture of dimethyl adipate, dimethyl glutarate, and dimethyl succinate. Its density is about 9.0 pounds per gallon.

DBE is a relatively low-cost solvent because the raw material from which it is made, diabasic acid (DBA), is a by-product of a Du Pont manufacturing process. DBA is a mixture of adipic acid, glutaric acid, and succinic acid.

DBE is now a constituent in the solvent mixture used for some lacquer and enamel automotive topcoats, epoxy primers, polyester coil coatings, and can coatings. About 25 million pounds were so used in 1980, mostly in automotive coatings. The total amount of organic solvents used in coatings annually is about 4 billion pounds.

Du Pont believes DBE has the potential for use in any coating which contains organic solvent. This includes the higher-solids coatings which many coaters are, or soon will be, using to comply with State regulations for VOC emissions. Du Pont estimates that DBE could constitute from 10-40 percent, by weight, of such higher-solids coatings.

In spite of its low vapor pressure and cost, which Du Pont claims make DBE a very desirable solvent for higher-solids coatings, DBE has not been so used. Du Pont claims this is because State regulations, which limit the mass of VOC emitted from coating operations, have led coating formulators to seek less dense solvents.

Du Pont petitioned the EPA to provide States with the option of allowing the owners or operators of surface coating operations to make an adjustment for the relatively high density of DBE when determining compliance with State VOC emission regulations. Specifically, Du Pont requested that an assumed 7.36 pounds per gallons be used for calculations regarding the quantity of DBE in a coating rather than its actual density of 9.0 pounds per gallon.

On June 18, 1982, the EPA published a notice in the Federal Register (47 FR 26452) which stated that the Agency would approve Du Pont's petition unless comments giving sufficient reasons to deny it were received. Eleven comments were submitted in response to this notice. Four were from State air pollution control agencies (Illinois, Maryland, New Jersey and Rhode Island). Six were from manufacturers of coatings, solvents, and resins (Angus Chemical, Dow Chemical, Eastman Kodak, Glidden, Union Carbide, and the petitioner, Du Pont). One was from a consultant (Mr. John H. Daniel, Jr.).

The Comments from Illinois, Rhode Island, John Daniel, Jr., Eastman Kodak, Glidden, Dow Chemical, and Union Carbide, recommended against approving the Du Pont petition. The comments from Angus Chemical and Du Pont recommend the petition be approved. The comments from Maryland and New Jersey do not specifically state a position on the petition. A summary of the comments follows:

One State agency and three manufacturers expressed concern that EPA Reference Method 24 (particularly ASTM D-2369-81) could no longer be used to determine the VOC content of coatings which contain DBE if the petition were approved. The State agency suggested approval of the petition would create a problem of enforceability because it would render the relatively inexpensive ASTM-D-2369-81 ineffective, and force the need for a more costly and time-consuming analysis. The three manufacturers said they knew of no acceptable analytical method that could be used to determine the solvent content of a coating if the petition were approved. Two of these manufacturers added that approval of the petition would create confusion over the VOC content of coatings.

Two manufacturers commented on the discussion of the toxicity of DBE and other coating solvents in the petition. One stated that toxicity is irrelevant since the purpose of State regulations which limit VOC emissions from surface coatings is to reduce ambient ozone levels. The other took issue with the petitioner's statement that ethylene glycol monomethyl and monoethyl

ethers, two solvents for which Du Pont indicated there were some unfavorable toxicity data, are competitors with DBE in the formulation of coating solvent mixtures. This manufacturer stated that since these two solvents are more volatile than DBE, DBE is not an appropriate substitute. He suggested that ethylene glycol ethers and ether esters, which have evaporation rates comparable to that of DBE, are more likely to compete directly with DBE. The commenter knew of no data which raised any concern about the toxicity of these less volatile solvents.

Four manufacturers and the consultant commented on the possibility of similar petitions being submitted for other high-density (greater than 7.36 pounds per gallon) solvents. One manufacturer supported Du Pont's petition and named several other solvents for which he felt a similar density adjustment would be appropriate. The other three manufacturers and the consultant all suggested that approval of Du Pont's petition would lead to numerous additional requests for density adjustments. One of these manufacturers stated that EPA's use of 7.36 pounds per gallon as the average solvent density already accounts for the wide density range of coating solvents. All three of these manufacturers produce and sell solvents which would be candidates for similar waivers, yet none favored approval of the petition.

Two manufacturers and the consultant commented that there is no sound scientific foundation for approval of the petition. Another manufacturer suggested that the market place should be allowed to evaluate competitive products without interference from an artificial exemption. One State agency stated that approving DuPont's petition would result in reverse discrimination against other solvents.

Two manufacturers and three State agencies questioned the effect that approval of Du Pont's petition would have no State efforts to reduce ambient ozone levels. They asked if DBE is an ozone generator and what the effect of allowing greater mass emissions of DBE would be.

The comments on toxicity, lack of agreement on competing solvents, and possibility of similar petitions for many other solvents emphasize the competitiveness and complexity of the coating solvents market. Many different solvents and solvent mixtures can be used with the same resin system. This freedom of substitution is not unlimited in that the solvent system can affect the final appearance and performance of the dry coating. Certainly, Du Pont believes that approval of the petition would enhance the marketability of DBE. If, however, similar waivers were authorized for other high-density solvents, many of which appear to compete directly with DBE, at least part of this advantage would be lost and other factors such as solvency properties, cost and toxicity (or absence thereof) would return to preeminence as the determinants of the market demand for specific solvents. Since as DBE is formed from a by-product of another process, it likely will remain a low-cost solvent, thereby maintaining some advantage over its competition.

DBE is photochemically reactive, and when emitted to the atmosphere, contributes to the formation of ozone. Du Pont claimed in its petition that DBE forms less ozone per unit mass emitted than many other common coating solvents. This claim was based upon a theoretical reactivity scale developed by Bufalini (see "Ozone Formation Potential of Organic Compounds," *Environmental Science and Technology*, September 1976). The validity of this theoretical scale has not been proven.

The atmospheric photochemical reactions which form ozone are very complex. They depend not only on the type and quantity of VOC present, but also on meteorological conditions and the presence of other precursors. The EPA recognized these complexities and the impracticality of trying to base an ozone control program on either the rate of ozone formation or the quantity of ozone formed from each individual VOC. In its July 8, 1977, (42 FR 35314) policy statement for the control of VOC's, the EPA classified all but a few organic compounds as photochemically reactive.

Since 1977, the EPA has continued to study atmospheric photochemical reactions. These studies will continue, and, in time, may provide a better understanding of the contribution of specific organic compounds to the formation of ozone. The present state of the science, however, does not permit EPA to discriminate between the relative ozone formation potential of specific compounds other than to identify those that are of negligible photochemical reactivity.

Many different VOC's are used as coating solvents and each individual coating contains a mixture of several solvents. This wide variety of solvent mixtures adds to the impracticality of any attempt to quantify the reaction rate or total ozone potential of the solvents in an individual coating. For these reasons, both the EPA and States have chosen to restrict the total mass of photochemically reactive VOC's that can be emitted from coatings.

The June 18, 1982, **Federal Register** notice stated that EPA would approve Du Pont's petition unless comments were received giving sufficient reasons to deny it. Seven commenters recommended denying the Du Pont petition and gave several reasons for their recommendation. Because of this, the EPA is denying Du Pont's petition.

Dated: January 7, 1983.

Kathleen Bennett,

Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 83-1435 Filed 1-18-83; 8:45 am]

BILLING CODE 6560-50-M

ENVIRONMENTAL PROTECTION AGENCY

[AD-FRL 2417-2]

Control Techniques Guideline Document; VOC Emissions From Volatile Organic Liquid Storage in Floating and Fixed Roof Tanks

AGENCY: Environmental Protection Agency (EPA).

ACTION: Release of draft document for public review.

SUMMARY: The draft Control Techniques Guideline (CTG) document for control of volatile organic compounds (VOC) emissions from volatile organic liquids (VOL) storage in floating and fixed roof tanks is available for public review and comment. This informational document has been prepared to assist States in analyzing and determining reasonably available control technology (RACT) for VOC emissions from VOL storage in floating and fixed roof tanks.

DATES: Comments should be submitted, in duplicate if possible, to the Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Mr. James Durham, on or before October 6, 1983.

ADDRESSES: Comments will be available for public inspection and copying between 8:30 a.m. and 4:00 p.m., Monday through Friday, at the Chemicals and Petroleum Branch, Room 730, Emission Standards and Engineering Division, Environmental Protection Agency, 411 West Chapel Hill Street, Durham, North Carolina.

Copies of the draft CTG document may be obtained by contacting the Environmental Research Library (MD-35), (919) 541-2777, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Please refer to "Guidelines Series—Control of Volatile Organic Compound Emissions from Volatile Organic Liquid Storage in Floating and Fixed Roof Tanks."

FOR FURTHER INFORMATION CONTACT: Mr. James Durham, (919) 541-5671, Chemicals and Petroleum Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION: On March 17 and 18, 1981, the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) reviewed a preliminary draft CTG document for control of VOC emissions from VOL storage vessels. Nineteen comments were received from industry representatives and trade groups. This draft CTG document was prepared based on the evaluation of the public comments received at NAPCTAC, and consideration of supplemental emissions data test provided by the American Petroleum Institute (API). The API initiated a major internal floating roof tank emissions testing program in 1980. Many commenters suggested that the EPA delay the development of the CTG until new emissions test data from API were available. This program, and data analysis were completed in the latter half of 1982, and the data were made available to the EPA. The API testing program resolves issues concerning previous emissions test work done by the EPA and industry. After analysis and careful consideration of the test methodology employed by API and results obtained by API, the EPA has decided to utilize the new API data for the purposes of this CTG.

This CTG document is part of the third group of CTG documents published to assist the States in determining RACT for various stationary sources of VOC emissions. CTG documents are informational in nature and provide State and local air pollution control agencies with an initial information base for proceeding with their own analysis of RACT for specific stationary source categories of VOC emissions located within areas where an extension was granted to the attainment of the national ambient air quality standard for ozone. The CTG document reviews existing information and data concerning the technology and cost of various control techniques to reduce VOC emissions from VOL storage vessels.

Under Executive Order 12291, the EPA must judge whether a rule is "major" and therefore subject to the requirements of a regulatory impact analysis. This CTG document is not a "rulemaking," rather it is a notice of availability. This notice and the draft CTG documents were submitted to the Office of Management and Budget (OMB) for review.

Dated: July 5, 1983.

Charles L. Elkins,

Acting Assistant Administrator for Air, Noise and Radiation.

[FR Doc. 83-22493 Filed 8-19-83; 8:45 am]

BILLING CODE 6560-50-M

[OPRM-FRL 2419-5]

Agency Information Collection Activities Under OMB Review

AGENCY: Environmental Protection Agency (EPA).

[AD-FRL 2468-8]

Control Techniques Guideline Document; Control of Volatile Organic Compound Emissions From Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins

AGENCY: Environmental Protection Agency (EPA).

ACTION: Release of final control techniques guideline (CTG) document.

SUMMARY: A final CTG document for control of volatile organic compund (VOC) emissions from manufacture of high-density polyethylene, polypropylene, and polystyrene resins is available. This final CTG document provides guidance for the States in determining reasonably available control technology (RACT) for VOC emissions from manufacture of high-density polyethylene, polypropylene, and polystyrene resins.

ADDRESSES: Copies of the final CTG document may be obtained by contacting the Environmental Research Library (MD-35), (919) 541-2777, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Please refer to "Guidelines Series—Control of Volatile Organic Compund Emissions from Manufacture of High-Density Polyethylene, Polypropylene, and Polystyrene Resins." EPA-450/3-83-008. Comments received on the draft CTG document are attached as an appendix to each final CTG document and are also available for public inspection and copying between 8:30 a.m. and 4:00 p.m., Monday through Friday, at the Chemicals and Petroleum Branch, Room 736, U.S. Environmental Protection Agency, 411 West Chapel Hill Street, Durham, North Carolina 27701.

FOR FURTHER INFORMATION CONTACT: Mr. James C. Berry, (919) 541-5605, Chemicals and Petroleum Branch (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION: On May 6, 1982, (47 FR 19580), the EPA announced the availability of the draft CTG document for "Control of Volatile Organic Compund Emissions from Manufacture of High-density Polyethylene, Polypropylene, and Polystyrene Resins" for public review. Comments were received from six industry representatives and trade groups. The final CTG document was prepared based on the evaluation of the public comments. The major change in the final document is including flares in the definition of RACT. Data available on the performance of flares when the draft CTG was published did not support a conclusion that flares would reduce VOC emissions by 98 percent or greater, consequently flares were not included in the definition of RACT. Three commenters, however, argued that flares should be included in the definition of RACT.

In January 1983, "A Report on a Flare Efficiency Study" was published by the Chemical Manufacturers Association. This report covers the results of a study designed to measure the performance of flares in reducing VOC emissions. The results demonstrate that under certain conditions, flares will reduce VOC emissions by at least 98 percent.

Finally, the RACT level for polystyrene plants using continuous process was changed from 0.3 kg of VOC/1000 kg of product to 0.12 kg of VOC/1000 kg of product based on recent information concerning current industry practice.

These CTG documents are part of the third group of CTG documents published to assist the States in determining RACT for various stationary sources of VOC emissions. CTG documents provide State and local air pollution control agencies with an initial information base for proceeding with their own analysis of RACT for specific stationary source categories of VOC emissions located within areas where an extension was granted to the attainment of the national ambient air quality standard (NAAQS) for ozone. The CTG documents review existing information and data concerning the technology and cost of various control techniques to reduce VOC emissions.

This CTG is not a "rule" as defined by the Administrative Procedure Act (5 U.S.C. 551 et seq.). It is a "rule" for purpose of Executive Order 12291, because it is designed to implement an EPA policy. Under Executive Order 12291, EPA must judge whether a rule is "major" and therefore, subject to the requirements of a regulatory impact analysis. These CTG documents are not "major rules" because they do not impose any new requirements. This notice and the final CTG documents were submitted to the Office of Management and Budget (OMB) for review. Any comments from the OMB to the EPA and any EPA responses to those comments are available for public inspection. See the **ADDRESSES** section of this notice for the times and addresses.

Dated: June 9, 1983.

Charles L. Elkins,

Acting Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 83-30533 Filed 11-10-83; 8:45 am]

BILLING CODE 6560-50-M

[AD-FRL 2520-7]

Control Techniques Guideline Document; VOC Equipment Leaks From Natural Gas/Gasoline Processing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Release of final control techniques guideline (CTG) document.

SUMMARY: Final CTG document for control of equipment leaks of volatile organic compounds (VOC) from natural gas/gasoline processing plants is available. This final CTG document provides guidance for the States in determining reasonably available control technology (RACT) for VOC equipment leaks from natural gas/gasoline processing plants.

ADDRESSES: Copies of the final CTG document may be obtained by contacting the Environmental Research Library (MD-35), (919) 541-2777, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Please refer to "Guideline Series—Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing," EPA-450/3-83-007. Comments received on the draft CTG document are attached as an appendix to the final CTG document and are also available for public inspection and copying between 8:30 a.m. and 4:00 p.m., Monday through Friday at the Chemicals and Petroleum Branch, Room 736, Environmental Protection Agency, 411 West Chapel Hill Street, Durham, North Carolina.

FOR FURTHER INFORMATION CONTACT: Mr. J. F. Durham, (919) 541-5671, Chemicals and Petroleum Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION: The EPA announced the availability for public review of the draft CTG for VOC equipment leaks from natural gas/gasoline processing plants on January 25, 1982 (47 FR 3403). Twelve comments were received on this draft documen from industry representatives and trade groups. The final CTG document was prepared based on the evaluation of the public comments and on consideration of supplemental data analyses provided subsequent to the issuance of the draft CTG document in "Fugitive Emission Sources of Organic Compounds—Additional Information on Emissions, Emission Reductions, and Costs," or AID EPA-450/3-82-010 (April 1982). Several major changes were made in the final RACT determination. The emission reduction estimates were revised based upon the methodology presented in the AID, and an exemption from the leak detection and repair requirements was provided for plants that do not fractionate natural gas liquids and that have feed capacities of less than 200 thousand cubic meters (10 million cubic feet) per day. Additional exemptions have been provided in the final CTG. All leaks that cannot be repaired on-line no longer have to be repaired within 1 year of detection and control of valve positioner emissions from gas-operated control valves is not required. Exemption from the routine leak detection and repair requirement is provided for equipment in dry gas service (containing less than 1.0 percent VOC by weight), in heavy liquid service, and in vacuum service. Reciprocating compressor seals in wet gas service (i.e., containing between 1.0 and 50 percent VOC by weight) are exempted from RACT requirements if there is no control device available in the gas plant.

This CTG document is part of the third group of CTG documents published to assist the States in determining RACT for various stationary sources of VOC emissions. CTG documents provide State and local air pollution control agencies with an initial information base for proceeding with their own analysis of RACT for specific stationary source categories of VOC emissions located within areas where an extension was granted to the attainment of the national ambient air quality standard (NAAQS) for ozone. The CTG documents review existing information and data concerning the technology and cost of various control techniques to reduce VOC emissions.

This CTG is not a "rule" as defined by the Administrative Procedure Act (5 U.S.C. 551 et seq.). It is a "rule" for purposes of Executive Order 12291, because it is designed to implement an EPA policy. Under Executive Order 12291, EPA must judge whether a rule is "major" and therefore, subject to the requirements of a regulatory impact analysis. This CTG document is not a "major rule" because it does not impose any new requirements. This notice and the final CTG documents were submitted to the Office of Management and Budget (OMB) for review. Any comments from the OMB to the EPA and any EPA responses to those comments are available for public inspection. See the **ADDRESSES** secton of this notice for the times and addresses.

Dated: June 6, 1984

Sheldon Meyers,

Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 84-3128 Filed 2-3-84; 8:45 am]

BILLING CODE 6560-50-M

II. New Source Performance Standards for Sources of Volatile Organic Compounds—Final Rules, Proposed Rules, Notices, and Announcements

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After June 11, 1973 and Prior to May 19, 1978

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

(Secs. 111, 301(a), Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)))

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-73, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-97578.

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen.

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic trans-

fer facilities to pipelines or any other forms of transportation.

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 39 FR 20794, June 14, 1974; 45 FR 23379, Apr. 4, 1980]

§ 60.112 Standard for volatile organic compounds (VOC).

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.113 Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112.

[45 FR 23379, Apr. 4, 1980]

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After May 18, 1978

SOURCE: 45 FR 23379, Apr. 4, 1980, unless otherwise noted.

§ 60.110a Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons) and for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

§ 60.111a Definitions.

In addition to the terms and their definitions listed in the Act and Subpart A of this part the following definitions apply in this subpart:

(a) "Storage vessel" means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-78, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-975-78.

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

(f) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(g) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

(h) "Liquid-mounted seal" means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.

(i) "Metallic shoe seal" includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(j) "Vapor-mounted seal" means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.

(k) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

§ 60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm^2 per meter of tank diameter (10.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in pargraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the

tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114a.

(b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

[45 FR 23379, Apr. 4, 1980, as amended at 45 FR 83229, Dec. 18, 1980]

§ 60.113a Testing and procedures.

(a) Except as provided in § 60.8(b) compliance with the standard prescribed in § 60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in § 60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall, and the secondary seal and the tank wall according to the following frequency and furnish the Administrator with a written report of the results within 60 days of performance of gap measurements:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)((B) of this section.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a ⅛" diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and

measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in § 60.112a(a)(1)(i) and § 60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

(2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

(i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.

(ii) The manufacturer's design specifications and estimated emission reduction capability of the system.

(iii) The operation and maintenance plan for the system.

(iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.114a Equivalent equipment and procedures.

(a) Upon written application from an owner or operator and after notice and opportunity for public hearing, the Administrator may approve the use of equipment or procedures, or both, which have been demonstrated to his satisfaction to be equivalent in terms of reduced VOC emissions to the atmosphere to the degree prescribed for compliance with a specific paragraph(s) of this subpart.

(b) The owner or operator shall provide the following information in the application for determination of equivalency:

(1) Emission data, if available, which can be used to determine the effectiveness of the equipment or procedures in reducing VOC emissions from the storage vessel. A complete description of the emission measurement method used must be included.

(2) The manufacturer's design specifications and estimated emission reduction capability of the equipment.

(3) The operation and maintenance plan for the equipment.

(4) Any other information which will be useful to the Administrator in evaluating the effectiveness of the equipment or procedures in reducing VOC emissions.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimat-

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Updated: 11/1/83

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Steam Generators (>250 million Btu/hr)	D	Utility and Industrial boilers (coal, oil, and gas)	Particulate SO_x NO_x	8/17/71	12/23/71 6/14/74 clarification		EPA-450/3-79-021 APTD-0711 EPA-450/2-76-030a&b
				10/21/83 (48 FR 48960)			
		Wood Residue Amendment	Part., SO_x, NO_x	1/17/79	11/22/76 (41 FR 51397)		
		Lignite fired steam generators	NO_x	12/22/76 (41 FR 55792)	3/7/78 (43 FR 9276)		
	Da	Utility boilers (solid, liquid, and gaseous fuels)	Part., SO_2, NO_x	9/19/78 (43 FR 42154	6/11/79 (44 FR 33581)		EPA-450/2-78-005a EPA-450/2-78-006a EPA-450/2-78-007a EPA-450/2-78-007a-1 EPA-450/3-79-021
	Db	Industrial boilers (coal, oil, gas, solid waste, wood and bagasse)	NO_x & Particulates	FY-83			
Municipal Incinerators (>50 tons per day)	E	Incinerators	Particulate	8/17/71	12/23/71	11/27/79 (44 FR 67939)	APTD-0711 EPA-450/3-79-009
Portland Cement Plants	F	Kiln, clinker cooler	Particulate	8/17/71	12/23/71	10/22/79 (44 FR 60761)	APTD-0711 EPA-450/3-79-012
Nitric Acid Plants	G	Process Equipment	NO_x	8/17/71	12/23/71	6/19/79	APTD-0711 EPA-450/3-79-013
Sulfuric Acid Plants	H	Process equipment	SO_x, acid mist	8/17/71	12/23/71	3/15/79 (44 FR 15742)	APTD-0711 EPA-450/3-79-003

U.S. EPA/Office of Air Quality Planning and Standards
Emission Standards & Engineer Division
Research Triangle Park, NC 27711

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Sulfuric Acid Plants 111(d)		Process equipment	Acid mist		10/18/77		EPA-450/2-77-019
Asphalt Concrete Plants	I	Process equipment	Particulate	6/11/73	3/8/74		EPA-450/2-74-003 APTD-1352a-c
						8/31/79 (44 FR 51225)	EPA 450/3-79-014
Petroleum Refineries	J	Fuel gas combustion devices FCCU catalyst regenerators	SO_2 Particulate, CO	6/11/73	3/8/74		EPA-450/2-74-003 APTD-1352a-c
		Claus sulfur recovery plants	SO_2, reduced sulfur compounds. H_2S	10/4/76 (41 FR 43866)	3/15/78 (43 FR 10866) 3/12/79 Amend		EPA-450/2-76-016a&b
		Definition of small claus sulfur recovery plants		3/20/79 (44 FR 1720)	10/25/79 (44 FR 61543)		
						10/22/79 (44 FR 60759)	EPA-450/3-79-008
		Clarification of which gaseous fuels are covered		3/3/80 (45 FR 13991)	12/1/80 (45 FR 79452)		
		FCCU Catalyst Regenerators	SOx	FY-83			
Petroleum Liquid Storage Vessels	K,Ka	Gasoline, crude oil, and distillate storage tanks >40,000 gallons capacity	VOC	6/11/73 5/18/78 Amend.	3/8/74 4/4/80 12/18/80 Correction (45 FR 83228)		APTD-1352a-c EPA-450/2-74-003
		Equivalency determination/ amendment		4/29/81 (46 FR 23984)	12/1/82 (47 FR 54258)		
Secondary Lead Smelters and Refineries	L	Blast and reverberatory furnaces, pot furnaces	Particulate	6/11/73	3/8/74		APTD-1352a-c EPA-450/2-74-003
						4/17/80 (45 FR 26304)	EPA-450/3-79-015

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Secondary Brass and Bronze Ingot Production Plants	M	Reverberatory and electric furnaces and blast furnaces	Particulate	6/11/73 (38 FR 15406)	3/8/74 (39 FR 9308)	6/19/79 (44 FR 35953)	APTD-1352a-c EPA450/2-74-003
Iron and Steel Mills	N	Basic oxygen process furnaces (BOPF) Primary emission sources	Particulate Opacity Standard	6/11/73 (38 FR 15406) 3/2/77 (39 FR 9308)	3/8/74 (39 FR 9318) 4/13/78 Amend. (43 FR 15602)		APTD-1352a-c EPA-450/2-74-003
	Na	Revision to be proposed for BOPF's, hot metal & skimming stations	Fugitive Particulate	1/20/83 (48 FR 2058)		3/21/79 (44 FR 17460)	EPA-450/3-78-116 EPA-450/3-82-005a
Sewage Treatment Plants	O	Sludge incinerators	Particulate	6/11/73	3/8/74 [illegible]/10/77 Amend. [illegible]2 FR 58520)	11/27/79 (44 FR 67934)	APTD-1352a-c EPA-450/3-79-010
Primary Copper Smelters	P	Roaster, smelting furnace, converter Dryers	SO_x Particulate	10/16/74	1/15/76 11/1/77 Amend. to G.P.	(FY-83)	EPA-450/2-74-002a
Primary Zinc Smelters	Q	Roaster Sintering machine	SO_x Particulate	10/16/74	1/15/76	10/8/82 (47 FR 44587)	EPA-450/2-74-002a
Primary Lead Smelters	R	Sintering machine, electric smelting furnace, converter Blast or reverberatory furnace, sintering machien discharge end	SO_x Particulate	10/16/74	1/15/76	10/8/82 (47 FR 44587)	EPA-450/2-74-002a
Primary Aluminum Reduction Plants	S	Pot lines and anode bake plants	Fluorides	10/23/74 9/19/78 Amend.	1/26/76 6/30/80 (45 FR 44202)		EPA-450/2-74-020a-c EPA-450/2-78-025a EPA-450/3-79-026

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Primary Aluminum Reduction Plants 111(d)		Pot lines and anode bake plants	Fluorides	4/11/79 Draft CTG	4/17/80 Final CTG		EPA-450/2-78-049a&b
Phosphate Fertilizer Plants	T	Wet process phosphoric acid	Fluorides	10/22/74	8/6/75		EPA-450/2-74-019a&b
	U	Superphosphoric acid	Fluorides				
	V	Diammonium phosphate	Fluorides			11/21/80	EPA-450/3-79-038R
	W	Triple superphosphate prod.	Fluorides	6/21/82 (47 FR 26750)	2/17/83 (48 FR 7128)		
	X	Granular trpl. superphos. strog	Fluorides				
Phosphate Fertilizer Plants 111(d)		Wet process phosphoric acid	Fluorides	5/12/76	3/1/77		
		Superphosphoric acid	Fluorides				
		Diammonium phosphate	Fluorides				
		Triple superphosphate prod.	Fluorides				
		Triple superphosphate storage	Fluorides				
Coal Cleaning Plants	Y	Air tables and thermal dryers	Particulate	10/24/74	1/15/76		EPA-450/2-74-021a-c
						4/14/81 (46 FR 21769)	EPA-450/3-80-022
Ferroalloy Production	Z	Specific furnaces	Particulate & CO	10/21/74	5/4/76		EPA-450/2-74-018
						1/26/81 (46 FR 8033)	EPA-450/3-80-041
Iron and Steel Mills	AA	Electric arc furnaces	Particulate	10/21/74	9/23/75		EPA-450/2-74-017a&b
						4/21/80 (45 FR 26910)	EPA-450/3-79-033
				8/17/83 (48 FR 37338)			EPA-450/3-82-020a

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Kraft Pulp Mills	BB	Digesters, lime kiln, recovery furnace, washer, evaporator, strippers, smelt & BLO tanks	Total reduced sulfur (TRS)	9/24/76	2/23/78	FY-83	EPA-450/2-76-014a&b
		Recovery furnace, lime kiln, smelt tank	Particulate	9/24/76	2/23/78 8/7/78 Amend.		
Kraft Pulp Mills 111(d)		Digesters, lime kiln, recovery furnace, washer, evaporator strippers, smelt & BLO tank	Total reduced sulfur (TRS)	2/23/78	5/22/79		EPA-450/2-78-003a&b
		Recovery furnace, lime kiln, smelt tank	Particulate	2/23/78	5/22/79		
Glass Manufacturing Plants	CC	Glass melting furnace	Particulates	6/15/79 (44 FR 34840)	10/7/80 (45 FR 66742)		EPA-450/3-79-005a&b
Grain Elevators	DD	Truck loading and unloading stations, barge or ship loading and unloading stations, railcar loading & unloading stations, and grain handling operations	Particulates	1/13/77	8/3/78		EPA-450/2-77-001a&b
Metal Furniture	EE	Each metal furniture surface coating operation	VOC	11/28/80 (45 FR 79390)	10/29/82 (47 FR 49278)		EPA-450/3-80-007a&b
Stationary Internal Combustion Engines	FF	Each IC engine	NO_x	7/23/79 (44 FR 43152)			EPA-450/2-78-125a
Stationary Gas Turbines	GG	Each gas turbine	NO_x, SO_x	10/3/77 4/15/81 Amend. (46 FR 22005)	9/10/79 1/27/82 (47 FR 3767)	10/6/83 (48 FR 45701)	EPA-450/2-77-017a&b

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Lime Manufacturing Plants	HH	Rotary kiln, hydrator Revision & Response to Court Remand	Particulates	5/3/77 9/2/82 (47 FR 38832)	3/7/78		EPA-450/2-77-007b
Sodium Carbonate	II	Calciners, dryers, bleachers	Particulates	10/15/80 (45 FR 68616)	9/22/81 Withdrawn (46 FR 46813)		EPA-450/3-80-029a
Degreasers (Organic Solvent Cleaners)	JJ	Cold cleaner, vapor degreaser, conveyorized degreaser	VOC, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, methylene chloride, trichlorotrifluoroethane	6/11/80 (45 FR 39766) 4/21/81 Applicability date deferred (46 FR 22768)			EPA-450/2-78-045a
Lead Acid Batteries	KK	Lead oxide production grid casting, paste mixing, three-process operation and lead reclamation	Lead	1/14/80 (45 FR 2790)	4/16/82 (47 FR 16564)		EPA-450/3-79-028a&b
Metallic Minerals	LL	Metallic mineral processing operations prior to metal reduction	Particulates	8/24/82 (47 FR 36859)			EPA-450/3-81-009a
Automobile and Light-Duty Truck Surface Coating Operations	MM	Prime, guide coat, and top coat operations at assembly plants	VOC emissions	10/5/79	12/24/80 (45 FR 85415)		EPA-450/3-79-030a&b
		Innovative Technology Waivers		8/6/82 (47 FR 34342)	2/4/83 (48 FR 5452)		
		Prime Coat Revisions		7/29/82 (47 FR 32743)			
Phosphate Rock Plants	NN	Grinding, drying and calcining facilities	Particulates	9/21/79 (44 FR 54970)	4/16/82 (47 FR 16582)		EPA-450/3-79-017a&b

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Perchloroethylene Dry Cleaning	OO	Dryer, washers, filters, stills, muck cookers	VOC	11/25/80 (45 FR 78174)			EPA-450/3-79-029a
Ammonium Sulfate	PP	Ammonium sulfate dryer	Particulates	2/4/80 (45 FR 7758)	11/12/80 (45 FR 74846)		EPA-450/3-79-034a&b
Graphic Arts (Rotogravure)	QQ	Each publication rotogravure printing press Correction to Promulgation	VOC	10/28/80 (45 FR 71538)	11/8/82 (47 FR 50644) 1/10/83 (48 FR 1056) correction		EPA-450/3-80-031a&b
Pressure Sensitive Tapes & Labels Coating	RR	Adhesive coating line, release coating line, precoat coating line	VOC	12/30/80 (45 FR 86278)	10/18/83 (48 FR 48368)		EPA-450/3-80-003a&b
Large Appliances	SS	Each surface coating operation	VOC	12/24/80 (45 FR 85085)	10/27/82 (47 FR 47778)		EPA-450/3-80-037a&b
Metal Coil Coating	TT	Each prime coating operation, each finish coat operation Correction to Promulgation	VOC	1/5/81 (46 FR 1102)	11/1/82 (47 FR 49606) 1/10/83 (48 FR 1056)		EPA-450/3-80-035a&b
Asphalt Roofing	UU	Blowing stills, saturator, asphalt storage tanks, minerals handling, and storage facilities	Particulate	11/18/80 (45 FR 76427) 5/26/81 Amend. (46 FR 28180)	8/6/82 (47 FR 34137)		EPA-450/3-80-021a
SOCMI Fugitive	VV	Fugitive sources grouped within a process unit. Notice of "AID" Availability	VOC	1/5/81 (46 FR 1136) 5/7/82 (47 FR 19724)	10/18/83 (48 FR 48328)		EPA-450/3-80-033a&b EPA-450/3-82-010
Beverage Can Coatings	WW	Each exterior base coat operation, overvarnish coating operation and inside spray coating operation at 2 and 3 piece can plants	VOC	11/26/80 (45 FR 78980)	8/25/83 (48 FR 38728)		EPA-450/3-80-036a&b

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Bulk Gasoline Terminals	XX	Gasoline terminals - total of all loading racks	VOC	12/17/80 (45 FR 83126)	8/18/83 (48 FR 37578)		EPA-450/3-80-038a&b
Electric Arc Furnaces in a Ferrous Foundry	YY	Electric arc furnaces	Particulates				
	ZZ	Not Used					
VOL Storage Vessels	AAA	Each storage tanks	VOC	FY-83			
Rubber Tires	BBB	Undertread cementing, tread end cementing, sidewall cementing, bead cementing, green tire spraying, common affected facility	VOC	1/20/83 (48 FR 2676)			EPA-450/3-81-008a
Not used	CCC						
Polymers and Resins	DDD	Raw material preparation, polymerization, material recovery, product finishing, product storage process sections, fugitive emissions	VOC	FY-83			
By-Product Coke Oven Battery Stacks	EEE	Coke oven battery	Particulate	No schedule			
Flexible Vinyl Coating and Printing Operat.	FFF	Rotogravure printing and coating of flexible vinyl products	VOC Supplement	1/18/83 (48 FR 2276) 10/11/83 (48 FR 46224)			EPA-450/3-81-016a

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Petroleum Refineries	GGG	(1) Each compressor (2) fugitive emission sources grouped within a process unit	VOC	1/4/83 (48 FR 279)			EPA-450/3-81-015a
Synthetic Fiber Production Facilities	HHH	Solven-spun synthetic fiber manufacturing facilities	VOC	11/23/82 (47 FR 52932)			EPA 450/3-82-011a
SOCMI - Air Oxidation	III	Manufacture of synthetic organic chemicals via air oxidation processes	VOC	10/31/83 (48 FR 48932)			EPA-450/3-82-001a
Petroleum Dry Cleaning	JJJ	Drycleaning equipment in which petroleum solvent is used	VOC	12/14/82 (47 FR 56118)			EPA-450/3-82-012a
Crude Oil & Natural Gas Production	KKK	Crude oil & natural gas production facilities Fugitive emission sources	VOC	FY-83			
Crude Oil & Natural Gas Production	LLL	Crude oil and natural gas production	SO_x	FY-83			
Coke Oven Wet Quenching	MMM	Conventional wet quenching facilities	Particulate	FY-83			
Distillation Operations	NNN	Each distillation column in a petroleum refinery & synthetic organic chemical plant used in making one of 220 chemicals	VOC	FY-83			

STATUS OF STANDARDS OF PERFORMANCE
New Source Performance Standards

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Non Metallic Minerals (includes lightweight aggregate, gypsum, and perlite)	000	Each crusher, grinding mill, screening operation, bucket conveyor, bagging operation, storage bin, enclosed truck or railcar loading station.	Particulate	8/31/83 (48 FR 39566)			EPA-450/3-83-001a
Priority List	Categories of Stationary Sources			8/31/78 (43 FR 38872)	8/21/79 (44 FR 49222)		EPA-450/3-78-019
	Revised			5/13/81 (46 FR 25601)	1/8/82 (47 FR 950)		EPA-450/3-79-023

STATUS OF STANDARDS OF PERFORMANCE
Hazardous Pollutants

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No
	B	Unused (formerly used for asbestos/see Subpart M)					
Beryllium	C	Extraction plants, ceramic plants, foundries, incinerators, propellant plants, machining operations	Beryllium	12/7/71	4/6/73 (38 FR 8836)		APTD-1503
Beryllium, Rocket Motor Firing	D	Rocket motor firing	Beryllium	12/7/71	4/6/73 (38 FR 8836)		APTD-1503
Mercury	E	Ore processing, chlor-alkali manufacturing	Mercury	12/7/71	4/6/73 (38 FR 8836)		APTD-1503
				10/25/74	10/14/75		EPA-450/2-74-009a
Vinyl Chloride	F	Ethylene dichloride manufacture via O_2/HCl, vinyl chloride manufacture, polyvinyl chloride manufacture	Vinyl Chloride	12/24/75 6/2/77 Amend.	10/21/76		EPA-450/2-75-009a EPA-450/2-75-009b
						Review Doc. -	EPA-450/3-82-003
Coke Oven Emissions: Charging Topside Leaks Door Leaks	G	Wet-coal charged coke oven batteries	Coke oven emissions	FY-82			
Maleic Anhydride	H	Maleic anhydride production units that process >550 tons of maleic acid, maleic anhydride or both, per year	Benzene	4/18/80 (45 FR 26660)			EPA-450/3-80-001a
Ethylbenzene/ Styrene	I	Alkylation reactor section, EB hydroperoxidation reactor, hydrogen separation system	Benzene	12/18/80 (45 FR 83448)			EPA-450/3-79-035a

STATUS OF STANDARDS OF PERFORMANCE
Hazardous Pollutants

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Benzene Fugitive	J	Individual fugitive emission sources	Benzene	1/5/81 (46 FR 1165)			EPA-450/3-80-032a
Benzene Storage Vessels	K	Each storage tanks	Benzene	12/19/80 (45 FR 83952)			EPA-450/3-80-034a
		Notice of Additional Emission Date		11/24/82 (47 FR 53058)			
Coke Oven By-Product Recovery Plants	L	Process equipment, storage facilities , fugitive emission sources and sumps	Benzene				
Asbestos	M	Asbestos mills; roadway surfacing (asbestos tailings); demolition; spraying, fabricating, waste disposal and insulating.	Asbestos	12/7/71	4/6/73 (38 FR 8826)	(FY-82)	APTD-1503
				10/25/74	10/14/75 5/3/74 Revision		EPA-450/2-74-009a
		Amendment to Standard		7/13/83 (48 FR 32126)			
		Manufacture of shotgun shells asphalt concrete, products containing asbestos (textiles, cement, fireproofing and insulating materials, friction products, paper, millboard, felt, floor tile, paints, chlorinalkali coatings, caulks, adhesives and sealants)			3/2/77 Amend. 6/19/78 Amend.		EPA-450/2-77-030
Glass Mfg. Plants	N	Melting furnaces,	Inorganic arsenic	7/20/83 (48 FR 33112)			EPA-450/5-82-005 EPA-450/3-82-011a

STATUS OF STANDARDS OF PERFORMANCE
Hazardous Pollutants

Source	Subpart	Affected Facility	Pollutant	Proposal Date	Promulgation Date	Review Date	BID No.
Primary Copper Smelters	O	Low arsenic smelters (smelting furnace & copper converter)	Inorganic arsenic	7/20/83 (48 FR 33112)			EPA-450/3-83-010a
	P	High arsenic smelters (copper converters)	Inorganic arsenic	7/20/83 (48 FR 33112)			EPA-450/3-83-009a
Acrylonitrile		Undetermined					FY-83 Listing Scheduled
General Provisions		Amendment					FY-83 Proposal

§ 60.2 Definitions

"Volatile Organic Compound" means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

2. By adding Subpart MM as follows:

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

Sec.

60.390 Applicability and designation of affected facility.
60.391 Definitions.
60.392 Standards for volatile organic compounds.
60.393 Performance test and compliance provisions.
60.394 Monitoring of emissions and operations.
60.395 Reporting and recordkeeping requirements.
60.396 Reference methods and procedures.
60.397 Modifications.

Authority.—Sections 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart MM—Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations

§ 60.390 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in an automobile or light-duty truck assembly plant: each prime coat operation, each guide coat operation, and each topcoat operation.

(b) Exempted from the provisions of this subpart are operations used to coat plastic body components or all-plastic automobile or light-duty truck bodies on separate coating lines. The attachment of plastic body parts to a metal body before the body is coated does not cause the metal body coating operation to be exempted.

(c) The provisions of this subpart apply to any affected facility identified in paragraph (a) of this section that begins construction, reconstruction, or modification after October 5, 1979.

§ 60.391 Definitions.

(a) All terms used in this subpart that are not defined below have the meaning given to them in the Act and in Subpart A of this part.

"Applied coating solids" means the volume of dried or cured coating solids which is deposited and remains on the surface of the automobile or light-duty truck body.

"Automobile" means a motor vehicle capable of carrying no more than 12 passengers.

"Automobile and light-duty truck body" means the exterior surface of an automobile or light-duty truck including hoods, fenders, cargo boxes, doors, and grill opening panels.

"Bake oven" means a device that uses heat to dry or cure coatings.

"Electrodeposition (EDP)" means a method of applying a prime coat by which the automobile or light-duty truck body is submerged in a tank filled with coating material and an electrical field is used to effect the deposition of the coating material on the body.

"Electrostatic spray application" means a spray application method that uses an electrical potential to increase the transfer efficiency of the coating solids. Electrostatic spray application can be used for prime coat, guide coat, or topcoat operations.

"Flash-off area" means the structure on automobile and light-duty truck assembly lines between the coating application system (dip tank or spray booth) and the bake oven.

"Guide coat operation" means the guide coat spray booth, flash-off area and bake oven(s) which are used to apply and dry or cure a surface coating between the prime coat and topcoat operation on the components of automobile and light-duty truck bodies.

"Light-duty truck" means any motor vehicle rated at 3,850 kilograms gross vehicle weight or less, designed mainly to transport property.

"Plastic body" means an automobile or light-duty truck body constructed of synthetic organic material.

"Plastic body component" means any component of an automobile or light-duty truck exterior surface constructed of synthetic organic material.

"Prime coat operation" means the prime coat spray booth or dip tank, flash-off area, and bake oven(s) which are used to apply and dry or cure the initial coating on components of automobile or light-duty truck bodies.

"Purge" or "line purge" means the coating material expelled from the spray system when clearing it.

"Solvent-borne" means a coating which contains five percent or less water by weight in its volatile fraction.

"Spray application" means a method of applying coatings by atomizing the coating material and directing the atomized material toward the part to be coated. Spray applications can be used for prime coat, guide coat, and topcoat operations.

"Spray booth" means a structure housing automatic or manual spray application equipment where prime coat, guide coat, or topcoat is applied to components of automobile or light-duty truck bodies.

"Surface coating operation" means any prime coat, guide coat, or topcoat operation on an automobile or light-duty truck surface coating line.

"Topcoat operation" means the topcoat spray booth, flash-off area, and bake oven(s) which are used to apply and dry or cure the final coating(s) on components of automobile and light-duty truck bodies.

"Transfer efficiency" means the ratio of the amount of coating solids transferred onto the surface of a part or product to the total amount of coating solids used.

"VOC content" means all volatile organic compounds that are in a coating expressed as kilograms of VOC per liter of coating solids.

"Waterborne" or "water reducible" means a coating which contains more than five weight percent water in its volatile fraction.

(b) The nomenclature used in this subpart has the following meanings:

C_{aj} = concentration of VOC (as carbon) in the effluent gas flowing through stack (j) leaving the control device (parts per million by volume).

C_{bi} = concentration of VOC (as carbon) in the effluent gas flowing through stack (i) entering the control device (parts per million by volume).

C_{ck} = concentration of VOC (as carbon) in the effluent gas flowing through exhaust stack (k) not entering the control device (parts per million by volume).

D_{ci} = density of each coating (i) as received (kilograms per liter).

D_{dj} = density of each type VOC dilution solvent (j) added to the coatings, as received (kilograms per liter).

D_r = density of VOC recovered from an affected facility (kilograms per liter).

E = VOC destruction efficiency of the control device.

F = fraction of total VOC which is emitted by an affected facility that enters the control device.

G = volume weighted average mass of VOC per volume of applied solids (kilograms per liter).

L_{ci} = volume of each coating (i) consumed, as received (liters).

L_{ci}' = volume of each coating (i) consumed by each application method (l), as received liters).

L_{dj} = volume of each type VOC dilution solvent (j) added to the coatings, as received (liters).

L_r = volume of VOC recovered from an affected facility (liters).

L_s = volume of solids in coatings consumed (liters).

M_d = total mass of VOC in dilution solvent (kilograms).

M_c = total mass of VOC in coatings as received (kilograms).

M_r = total mass of VOC recovered from an affected facility (kilograms).

N = volume weighted average mass of VOC per volume of applied coating solids after the control device

$$\left(\frac{\text{kilograms of VOC}}{\text{liter of applied solids}}\right),$$

Q_{aj} = volumetric flow rate of the effluent gas flowing through stack (j) leaving the control device (dry standard cubic meters per hour).

Q_{bi} = volumetric flow rate of the effluent gas flowing through stack (i) entering the control device (dry standard cubic meters per hour).

Q_{ck} = volumetric flow rate of the effluent gas flowing through exhaust stack (k) not entering the control device (dry standard cubic meters per hour).

T = overall transfer efficiency.

T_i = transfer efficiency for application method (i).

V_{si} = proportion of solids by volume in each coating (i) as received

$$\left(\frac{\text{liter solids}}{\text{liter coating}}\right), \text{ and}$$

W_{oi} = proportion of VOC by weight in each coating (i), as received

$$\left(\frac{\text{kilograms VOC}}{\text{kilograms coating}}\right).$$

§ 60.392 Standards for volatile organic compounds

On and after the date on which the initial performance test required by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility VOC emissions in excess of:

(a) 0.16 kilograms of VOC per liter of applied coating solids from each prime coat operation.

(b) 1.40 kilograms of VOC per liter of applied coating solids from each guide coat operation.

(c) 1.47 kilograms of VOC per liter of applied coating solids from each topcoat operation.

§ 60.393 Performance test and compliance provisions.

(a) Sections 60.8 (d) and (f) do not apply to the performance test procedures required by this section.

(b) The owner or operator of an affected facility shall conduct an initial performance test in accordance with § 60.8(a) and thereafter for each calendar month for each affected facility according to the procedures in this section.

(c) The owner or operator shall use the following procedures for determining the monthly volume weighted average mass of VOC emitted per volume of applied coating solids.

(1) The owner or operator shall use the following procedures for each affected facility which does not use a capture system and a control device to comply with the applicable emission limit specified under § 60.392.

(i) Calculate the volume weighted average mass of VOC per volume of applied coating solids for each calendar month for each affected facility. The owner or operator shall determine the composition of the coatings by formulation data supplied by the manufacturer of the coating or from data determined by an analysis of each coating, as received, by Reference Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the manufacturer of the coating to determine data used in the calculation of the VOC content of coatings by Reference Method 24 or an equivalent or alternative method. The owner or operator shall determine from company records on a monthly basis the volume of coating consumed, as received, and the mass of solvent used for thinning purposes. The volume weighted average of the total mass of VOC per volume of coating solids used each calendar month will be determined by the following procedures.

(A) Calculate the mass of VOC used in each calendar month for each affected facility by the following equation where "n" is the total number of coatings used and "m" is the total number of VOC solvents used:

$$M_c = M_c \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj}$$

[$\Sigma L_{dj} D_{dj}$ will be zero if no VOC solvent is added to the coatings, as received].

(b) Calculate the total volume of coating solids used in each calendar month for each affected facility by the following equation where "n" is the total number of coatings used:

$$L_s = \sum_{i=1}^{n} L_{ci} V_{si}$$

(c) Select the appropriate transfer efficiency (T) from the following tables for each surface coating operation.

Application Method	Transfer efficiency
Air Atomized Spray (waterborne coating)	0.39
Air Atomized Spray (solvent-borne coating)	0.60
Manual Electrostatic Spray	0.75
Automatic Electrostatic Spray	0.95
Electrodeposition	1.00

The values in the table above represent an overall system efficiency which includes a total capture of purge. If a spray system uses line purging after each vehicle and does not collect any of the purge material, the following table shall be used:

Application Method	Transfer efficiency
Air Atomized Spray (waterborne coating)	0.30
Air Atomized Spray (solvent-borne coating)	0.40
Manual Electrostatic Spray	0.62
Automatic Electrostatic Spray	0.75

If the owner or operator can justify to the Administrator's satisfaction that other values for transfer efficiencies are appropriate, the Administrator will approve their use on a case-by-case basis.

(*1*) When more than one application method (*J*) is used on an individual surface coating operation, the owner or operator shall perform an analysis to determine an average transfer efficiency by the following equation where "n" is the total number of coatings used and "p" is the total number of application methods:

$$T = \frac{\sum_{i=1}^{n}\sum_{j=1}^{p} V_{si}\, C_{oij}}{L_s}$$

(D) Calculate the volume weighted average mass of VOC per volume of applied coating solids (G) during each calendar month for each affected facility by the following equation:

$$G = \frac{M_o + M_d}{L_s\, T}$$

(ii) If the volume weighted average mass of VOC per volume of applied coating solids (G), calculated on a calendar month basis, is less than or equal to the applicable emission limit specified in § 60.392, the affected facility is in compliance. Each monthly calculation is a performance test for the purpose of this subpart.

(2) The owner or operator shall use the following procedures for each affected facility which uses a capture system and a control device that destroys VOC (e.g., incinerator) to comply with the applicable emission limit specified under § 60.392.

(i) Calculate the volume weighted average mass of VOC per volume of applied coating solids (G) during each calendar month for each affected facility as described under § 60.393(c)(1)(*i*).

(ii) Calculate the volume weighted average mass of VOC per volume of applied solids emitted after the control device, by the following equation: $N = G(1-F)$.

(A) Determine the fraction of total VOC which is emitted by an affected facility that enters the control device by using the following equation where "n" is the total number of stacks entering the control device and "p" is the total number of stacks not connected to the control device:

$$F = \frac{\sum_{i=1}^{n} Q_{bi}\, C_{bi}}{\sum_{i=1}^{n} Q_{bi}\, C_{bi} + \sum_{k=1}^{p} Q_{fk}\, C_{fk}}$$

If the owner can justify to the Administrator's satisfaction that another method will give comparable results, the Administrator will approve its use on a case-by-case basis.

(*1*) In subsequent months, the owner or operator shall use the most recently determined capture fraction for the performance test.

(B) Determines the destruction efficiency of the control device using values of the volumetric flow rate of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation where "n" is the total number of stacks entering the control device and "m" is the total number of stacks leaving the control device:

$$E = \frac{\sum_{i=1}^{n} Q_{bi}\, C_{bi} - \sum_{j=1}^{m} Q_{aj}\, C_{aj}}{\sum_{i=1}^{n} Q_{bi}\, C_{bi}}$$

(*1*) In subsequent months, the owner or operator shall use the most recently determined VOC destruction efficiency for the performance test.

(C) If an emission control device controls the emissions from more than one affected facility, the owner or operator shall measure the VOC concentration (C_{bi}) in the effluent gas entering the control device (in parts per million by volume) and the volumetric flow rate (Q_{bi}) of the effluent gas (in dry standard cubic meters per hour) entering the device through each stack. The destruction or removal efficiency determined using these data shall be applied to each affected facility served by the control device.

(iii) If the volume weighted average mass of VOC per volume of applied solids emitted after the control device (N_f), calculated on a calendar month basis is less than or equal to the applicable emission limit specified in § 60.392, the affected facility is in compliance. Each monthly calculation is a performance test for the purposes of this subpart.

(3) The owner or operator shall use the following procedures for each affected facility which uses a capture system and a control device that recovers the VOC (e.g., carbon adsorber) to comply with the applicable emission limit specified under § 60.392.

(i) Calculate the mass of VOC ($M_o - M_d$) used during each calendar month for each affected facility as described under § 60.393(c)(1)(ii).

(ii) Calculate the total volume of coating solids (L_s) used in each calendar month for each affected facility as described under § 60.393(c)(1)(i).

(iii) Calculate the mass of VOC recovered (M_r) each calendar month for each affected facility by the following equation: $M_r = LD_r$

(iv) Calculate the volume weighted average mass of VOC per volume of applied coating solids emitted after the control device during a calendar month by the following equation:

$$N = \frac{M_o + M_d - M_r}{L_s}$$

(v) If the volume weighted average mass of VOC per volume of applied solids emitted after the control device (N) calculated on a calendar month basis is less than or equal to the applicable emission limit specified in § 60.392, the affected facility is in compliance. Each monthly calculation is a performance test for the purposes of this subpart.

§ 60.394 Monitoring of emissions and operations.

The owner or operator of an affected facility which uses an incinerator to comply with the emission limits specified under § 60.392 shall install, calibrate, maintain, and operate temperature measurement devices as prescribed below:

(a) Where thermal incineration is used, a temperature measurement device shall be installed in the firebox. Where catalytic incineration is used, a temperature measurement device shall be installed in the gas stream immediately before and after the catalyst bed.

(b) Each temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5° C.

(c) Each temperature measurement device shall be equipped with a recording device so that a permanent record is produced.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414(0))

§ 60.395 Reporting and recordkeeping requirements.

(a) Each owner or operator of an affected facility shall include the data outlined in subparagraphs (1) and (2) in the initial compliance report required by § 60.8.

(1) The owner or operator shall report the volume weighted average mass of VOC per volume of applied coating solids for each affected facility.

(2) Where compliance is achieved through the use of incineration, the owner or operator shall include the following additional data in the control device initial performance test required by § 60.8(a) or subsequent performance tests at which destruction efficiency is determined: the combustion temperature (or the gas temperature upstream and downstream of the catalyst bed), the total mass of VOC per volume of applied coating solids before and after the incinerator, capture efficiency, the destruction efficiency of the incinerator used to attain compliance with the applicable emission limit specified in § 60.392 and a description of the method used to establish the fraction of VOC captured and sent to the control device.

(b) Following the initial report, each owner or operator shall report the volume weighted average mass of VOC per volume of applied coating solids for each affected facility during each calendar month in which the affected facility is not in compliance with the applicable emission limit specified in § 60.392. This report shall be postmarked not later than ten days after the end of the calendar month that the affected facility is not in compliance. Where compliance is achieved through the use of a capture system and control device, the volume weighted average after the control device should be reported.

(c) Where compliance with § 60.392 is achieved through the use of incineration, the owner or operator shall continuously record the incinerator combustion temperature during coating operations for thermal incineration or the gas temperature upstream and downstream of the incinerator catalyst bed during coating operations for catalytic incineration. The owner or operator shall report quarterly as defined below.

(1) For thermal incinerators, every three-hour period shall be reported during which the average temperature measured is more than 28°C less than the average temperature during the most recent control device performance test at which the destruction efficiency was determined as specified under § 60.393.

(2) For catalytic incinerators, every three-hour period shall be reported during which the average temperature immediately before the catalyst bed, when the coating system is operational, is more than 28° C less than the average temperature immediately before the catalyst bed during the most recent control device performance test at which destruction efficiency was determined as specified under § 60.393. In addition, every three-hour period shall be reported each quarter during which the average temperature difference across the catalyst bed when the coating system is operational is less than 80 percent of the average temperature difference of the device during the most recent control device performance test at which destruction efficiency was determined as specified under § 60.393.

(3) For thermal and catalytic incinerators, if no such periods occur, the owner or operator shall submit a negative report.

(d) The owner or operator shall notify the Administrator 30 days in advance of any test by Reference Method 25.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.396 Reference methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8 shall be used to conduct performance tests.

(1) Reference Method 24 or an equivalent or alternative method approved by the Administrator shall be used for the determination of the data used in the calculation of the VOC content of the coatings used for each affected facility. Manufacturers' formulation data is approved by the Administrator as an alternative method to Method 24. In the event of dispute, Reference Method 24 shall be the referee method.

(2) Reference Method 25 or an equivalent or alternative method approved by the Administrator shall be used for the determination of the VOC concentration in the effluent gas entering and leaving the emission control device for each stack equipped with an emission control device and in the effluent gas leaving each stack not equipped with a control device.

(3) The following methods shall be used to determine the volumetric flow rate in the effluent gas in a stack:

(i) Method 1 for sample and velocity traverses.

(ii) Method 2 for velocity and volumetric flow rate.

(iii) Method 3 for gas analysis, and

(iv) Method 4 for stack gas moisture.

(b) For Reference Method 24, the coating sample must be a 1-liter sample taken in a 1-liter container.

(c) For Reference Method 25, the sampling time for each of [illegible] must be at least one hour. The minimum sample volume must be 0.003 dscm, except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The Administrator will approve the sampling of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that the testing of representative stacks would yield results comparable to those that would be obtained by testing all stacks.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.397 Modifications.

The following physical or operational changes are not, by themselves, considered modifications of existing facilities:

(1) Changes as a result of model year changeovers or switches to larger cars.

(2) Changes in the application of the coatings to increase coating film thickness.

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Part V

Environmental Protection Agency

Innovative Technology Waivers for Five Automobile and Light-Duty Truck Surface Coating Operations

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2117-1]

Proposed Waivers From New Source Performance Standards; Innovative Technology Waivers for Five Automobile and Light-Duty Truck Surface Coating Operations

AGENCY: Environmental Protection Agency.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Environmental Protection Agency (EPA) proposes to grant, subject to the concurrence by the Governors of the States of Michigan, Missouri, Ohio, and Tennessee, innovative technology waivers, pursuant to Section 111(j) of the Clean Air Act, as amended (the Act), 42 U.S.C. 7411(j), for topcoat operations at the following automobile and light-duty truck assembly plants:

(1) General Motors Corporation (GM) Wentzville, Missouri plant

(2) GM Detroit, Michigan plant

(3) GM Orion Township, Michigan plant

(4) Honda of America Manufacturing, Inc. (Honda) Marysville, Ohio plant

(5) Nissan Motor Manufacturing Corporation U.S.A. (Nissan) Smyrna, Tennessee plant

These statutory waivers would provide an opportunity to demonstrate the capability of base coat/clear coat (BC/CC) topcoat coating systems to achieve greater emission reductions than required by the existing standards of performance for topcoat coating operations at automobile and light-duty truck assembly plants at lower costs.

The purpose of this notice is to invite public comment and to offer an opportunity to request a public hearing on the proposed innovative technology waivers.

DATES: *Comments.* Comments must be received on or before September 20, 1982.

Public Hearing. A public hearing (or hearings) will be held if requested. Persons wishing to request a public hearing must contact EPA by August 20, 1982. If hearings are requested, announcements of the dates and places will appear in separate Federal Register notices.

ADDRESSES: *Comments.* Under Section 307(d)(2), 42 U.S.C. 7607(d)(2), the Administrator is required to establish two separate rulemaking dockets for each rule that would apply only within the boundaries of one State. One copy of the docket is located in Washington, D.C., and a second copy is located at the EPA Regional Office for the affected State. Therefore, copies of all comments on a particular waiver action should be submitted to the Washington, D.C., docket and to the respective Regional Office docket.

One copy of each comment should be sent to: Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460. (Use appropriate docket number for plant waiver—see Table.)

A second copy of each comment should be sent to:

For: GM's Wentzville, Missouri plant: Environmental Protection Agency, Region VII, Attention: Mr. Charles Whitmore, Docket Number (see Table 1), 324 East 11th Street, Kansas City, Missouri 64106;

For: GM's Detroit, Michigan plant; GM's Orion Township, Michigan plant; and/or Honda's Marysville, Ohio plant: Environmental Protection Agency, Region V, Attention: Mr. Gary Gulezian, Docket Number (see Table 1), 230 S. Dearborn Street, Chicago, Illinois 60604.

For: Nissan's Smyrna, Tennessee plant: Environmental Protection Agency, Region IV, Attention: Mr. Brian Beals, Docket number (see Table 1), 345 Courtland Street, N.E. Atlanta, Georgia 30365.

TABLE I.—DOCKET NUMBERS

Plant	Docket No.
1. GM—Wentzville, Missouri	A-8211.
2. GM—Detroit, Michigan	A-8212.
3. GM—Orion Township, Michigan	A-8213.
4. Honda—Marysville, Ohio	A-8215.
5. Nissan—Smyrna, Tennessee	A-8216

The dockets may be inspected at the listed addresses between 8 a.m. and 4 p.m. on weekdays. A reasonable fee may be charged for copying.

Public Hearing. Persons wishing to request a public hearing should notify Ms. Naomi Durkee, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5624.

SUPPLEMENTARY INFORMATION:

Background

Current Regulations

On October 5, 1979, pursuant to Section 111 of the Clean Air Act, standards of performance were proposed to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed automobile and light-duty truck surface coating operations (44 FR 57792). Final standards were published in the Federal Register on December 24, 1980 (45 FR 85410).

Standards of performance under Section 111 are established at levels that reflect best demonstrated technology (BDT). For automobile and light-duty truck topcoat operations, BDT was determined to be the use of low-VOC content waterborne coatings applied with the best demonstrated air atomized spray techniques. The standard of 1.47 kg VOC per liter of applied coating solids for topcoat operations was based on the use of this coating system at three U.S. plants. The standard does not, however, require use of waterborne coatings. Any coating system capable of reducing VOC emissions to 1.47 kg VOC per liter of applied coating solids may be used. Other methods which could be used independently or in various combinations to achieve the topcoat standard are low-VOC content solvent-borne coatings, add-on control devices, such as incinerators and carbon adsorbers, and high efficiency coating application techniques.

Trends in Automobile Topcoats

Since the standard was proposed in 1979, the trend in the domestic automobile industry has been to develop and use low-VOC content solvent-borne topcoats with improved transfer efficiency, rather than more costly waterborne coatings, to reduce VOC emissions and improve finish quality. Low-VOC content, solid color topcoats are available for production line use. These coatings have been demonstrated to be of acceptable quality and appearance and, when used in combination with better transfer efficiency and/or bake oven emission control systems (i.e., energy efficient incinerators), will meet the standard.

Single coat solvent-borne metallic coatings which could meet the standard are also available. These coatings cannot, however, match the performance or appearance of metallic base coat/clear coat (BC/CC) topcoat systems which are being used on many imported vehicles. BC/CC topcoat systems consist of a relatively thin layer of highly pigmented metallic base coat

followed by a thicker layer of clear coat. BC/CC coatings have a more appealing appearance than single coat metallic topcoat systems and also offer improved chemical resistance and gloss retention. Vehicles coated with BC/CC systems are being imported in significant quantities and sold in the U.S. by both European and Japanese manufacturers. Because of the general appeal and acceptance by U.S. consumers of vehicles coated with the BC/CC system, U.S. automobile and light-duty truck manufacturers must duplicate the performance of this type of topcoat system to be competitive.

The BC/CC coatings that are being used in foreign plants contain relatively large quantities of VOC. If U.S. manufacturers used similar coatings, the only possible method of meeting the existing standards of performance for automobile and light-duty truck surface coating operations would be to use an entirely new generation of very expensive add-on controls to minimize emissions. BC/CC systems with VOC content low enough to comply without such add-on control are not yet commercially available. The coatings manufacturing companies are working with automobile manufacturers to develop lower VOC content BC/CC systems. The automobile manufacturers and equipment vendors are developing efficient spray coating methods for these coatings. The results of this intensive industry development program will ultimately permit the automobile companies to meet the topcoat standard and still apply BC/CC coatings to automobiles in sufficient number to meet market demand without having to use expensive add-on controls.

Requirements of Section 111(j)

Section 111(j) of the Clean Air Act sets forth provisions for the issuance of waivers for the development of innovative technology. In the 1977 Amendments to the Clean Air Act, Congress added this provision to encourage the use of innovative "technological systems of continuous emission reduction" for the control of air pollutants. Their intent in doing so was to provide a statutory incentive for the improvement of emission control technology and for reducing costs, environmental impacts, and energy usage of such technology.

Under Section 111(j) of the Act, upon request by the owner or operator of a new source and with the consent of the Governor of the State in which the source is located, the Administrator is authorized to grant a waiver from the requirements of Section 111 for a limited time period and under specific terms and conditions provided certain statutory prerequisites are satisfied. The Administrator must determine that:

a. The proposed innovative system has not been adequately demonstrated;

b. The proposed innovative system will operate effectively and there is substantial likelihood that the system will achieve greater continuous emission reduction than otherwise required or achieve an equivalent emission reduction at lower cost in terms of energy, economic, or nonair quality environmental impact;

c. The owner or operator of the proposed system has demonstrated to the Administrator's satisfaction that the system will not cause or contribute an unreasonable risk to public health, welfare, or safety; and

d. The proposed waiver for the specific innovative technological system is not in excess of the number of waivers necessary to ascertain whether or not such system will achieve the conditions set forth in "b" and "c" immediately above.

Additionally, Section 111(j)(1)(B) of the Act requires an innovative technology waiver to be granted on such terms and conditions during the waiver period as the Administrator determines necessary:

a. to ensure emissions from the source will not prevent attainment and maintenance of any national ambient air quality standards, and

b. to ensure proper functioning of the innovative technological system.

Waiver Requests

General Motors

On October 30, 1981, GM submitted a request for innovative technology waivers under Section 111(j) of the Clean Air Act for the topcoat operations at three automobile plants now under construction. GM currently plans to initiate production in the second quarter of 1983 at the Orion Township, Michigan, and the Wentzville, Missouri, plants; with start-up of the Detroit, Michigan, plant to be in the second half of 1984. GM claims they need to use BC/CC metallic topcoats on almost all of the cars produced at these plants so that they can compete with imported cars.

The lowest VOC content BC/CC coating that is demonstrated by GM and will definitely be available for production line use by the second quarter of 1983 is a topcoat system which is composed of a 20 volume percent solids base coat and a 42 volume percent solids clear coat (i.e. a 20/42 BC/CC coating). GM plans to start-up these plants using this coating system. The BC will be applied with air atomized spray. The CC will be applied with a combination of manual air spray and automatic electrostatic spray. The average coating transfer effeciency will be 50 pecent for BC and 67 percent for CC. The oven exhaust gas streams from all coating ovens will be incinerated. The oven incinerators will reduce overall VOC emissions by about 15 percent. Under these conditions BC/CC topcoat VOC emissions would be 3.2 kg VOC per liter of applied coating solids at each of the three plants.

Currently, GM has two BC/CC coatings under evaluation (a 38/53 BC/CC coating and a 48/54 BC/CC coating) that would meet the topcoat standard of performance with oven incineration and an average coating transfer efficiency of 50 percent for BC and 67 percent for CC. These coatings are expected to be in use by December 31, 1986.

Honda

On November 19, 1981, Honda submitted a request for an innovative technology waiver under Section 111(j) of the Clean Air Act for the topcoat operation at an automobile plant that is being built in Marysville, Ohio. The plant is scheduled to begin production by the end of 1982. Honda would like to coat all of their metallic topcoated cars with BC/CC coatings so that they can match the quality of their cars produced in Japan and exported to the U.S.

The lowest VOC content BC/CC coating that is demonstrated by Honda and will definitely be available for production line use by the end of 1982 is a 21/42 BC/CC coating. Honda plans to begin production using this coating system. The BC will be applied with air atomized spray. The CC will be applied with a combination of manual electrostatic spray and automatic electrostatic spray. The average coating transfer efficiency will be 50 percent for BC and 92 percent for CC. The resulting VOC emissions under these conditions would be 3.1 kg VOC per liter of applied coating solids. Honda does not plan to incinerate the oven exhausts. Honda's analysis indicates that oven incineration without recycle is very expensive and that with recycle, coating quality problems are created.

Honda is testing two higher solids content BC/CC coatings: a 32/42 BC/CC coating and a 35/53 BC/CC coating. The 32/42 coating is expected to be available by January 1, 1985, and Honda plans to begin using this coating at that time. This coating will result in emissions of 2.1 kg of VOC per liter of applied coating solids when applied at an overall averge transfer efficiency of 50 percent for BC and 92 percent for CC. Honda plans to

demonstrate and use the 35/55 BC/CC coating by December 31, 1986. This coating when applied at an average transfer efficiency of 50 percent for BC and 92 percent for CC will result in emissions of 1.46 kg of VOC per liter of applied coating solids and will meet the promulgated topcoat standard of performance.

Nissan

On March 12, 1982, Nissan submitted a request for an innovative technology waiver under Section 111(j) of the Clean Air Act for the topcoat operation at a light-duty truck plant that is being built in Smyrna, Tennessee. The plant is scheduled to begin production in August 1983. Nissan would like to coat all of their metallic topcoated light-duty trucks with BC/CC coatings so that they can match the quality of their light-duty trusks produced in Japan and exported to the U.S.

The lowest VOC content BC/CC coating that is demonstrated by Nissan and will be available for production line use by August 1983 is a 21/37 BC/CC coating. Nissan plans to begin production using this BC/CC coating system. The BC will be applied with a combination of air atomized spray, manual electrostatic spray, and automatic electrostatic spray. The CC will be applied with a combination of manual electrostatic spray and automatic electrostatic spray. The average coating transfer efficiency will be 69 percent for BC and 87 percent for CC. Incinerators on all bake oven exhaust will reduce overall emissions by 20 percent. Under these conditions BC/CC topcoat emissions would be 2.3 kg of VOC per liter of applied coating solids.

Nissan is testing a higher solids 32/45 BC/CC coating system. Nissan expects this coating to be available for dark metallic colors by August 1984 and in use for all dark metallic colors by August 1985. This coating is expected to be available for light metallic colors by August 1986. When applied at an average transfer efficiency of 69 percent for BC and 87 percent for CC, and with incineration of the oven exhaust, this coating will result in emissions of 1.3 kg of VOC per liter of applied coating solids and will meet the promulgated topcoat standard.

Conclusions

The GM, Honda, and Nissan waiver requests depend upon the development of lower VOC content metallic BC/CC topcoats than are currently available and demonstrated. Therefore, review of these waivers are discussed under the same headings below.

Technology Not Demonstrated

Both GM and Honda plan to use BC/CC metallic topcoat coatings on close to 100 percent of the automobiles produced at the plants for which they have requested waivers. Nissan plans to use BC/CC metallic topcoat coatings on about 60 percent of the light-duty trucks produced at the plant for which they have requested a waiver. The lowest VOC content BC/CC metallic topcoat coating expected to be available and demonstrated for GM, Honda, and Nissan at the time these plants will start-up will average between 20 and 21 volume percent solids for the base coat and between 37 and 42 volume percent solids for the clear coat (i.e., 20/42, 21/37, or 21/42 BC/CC coating). When these coating systems are applied with the best available coating application equipment demonstrated by each company and bake over exhaust incineration is used where feasible, emissions of 2.3 (Nissan), 3.1 (Honda), and 3.2 (GM) kilograms of VOC per liter of applied coating solids will result.

These emission levels are higher than the 1.47 kilograms of VOC per liter of applied coating solids allowed by the standards of performance for topcoat operations. Since GM and Honda will use BC/CC metallic topcoat coatings on close to 100 percent of the vehicles they produce, averaging emissions from solid color vehicles with emissions from BC/CC metallic vehicles, as is allowed within each topcoat operation by the standards of performance, will not enable them to meet the standards at start-up. If Nissan, as expected, uses solid colors on about 40 percent of the vehicles they produce, their overall average topcoat VOC emissions at start-up would be about 1.7 kilograms of VOC per liter of applied coating solids. This is also more than the topcoat standard of performance allows.

Higher solids BC/CC metallic topcoat coatings, which are in various stages of development and testing by GM, Honda, Nissan and others, include a 32/42 BC/CC coating, a 32/44 BC/CC coating, a 32/45 BC/CC coating, a 35/55BC/CC coating, a 38/54 BC/CC coating, and a 48/54 BC/CC coating. GM could meet the topcoat standard of performance with either the 38/54 or the 48/54 coating using the paint application equipment and bake oven exhaust incinerators that they plan to install at start-up of each of their three plants. Honda could meet the topcoat standard of performance with the 35/55 coating using the paint application equipment that they plan to install at start-up of their plant. Nissan could meet the topcoat standard of performance within the 35/45 coating using the paint application equipment and bake oven exhaust incinerators that they plan to install at start-up of their plant.

Development of these metallic topcoat BC/CC coatings to the point where they are compatible with high transfer efficiency coating equipment and ready for use on assembly lines is necessarily a time-consuming process. Achievement of the emission rates necessary to comply with the topcoat standards of performance is dependent not only upon continued development of these coatings, but also upon the continuing development and use of coating application techniques which result in high transfer efficiency of the sprayed solids to the automobile. Development and demonstration of these techniques are an integral part of the coatings development program.

In addition to the need to assure that the coatings can be applied under assembly-line conditions while achieving acceptable appearance and quality, there is also the need to assure durability of the coating. This requires long-term exposure testing.

Until the 32/45, the 35/55, the 38/54, or the 48/54 BC/CC coating is developed, compliance with the topcoat standard of performance using BC/CC coatings can only be achieved by limiting production of vehicles with BC/CC coatings or by using add-on controls. Limiting production of vehicles with BC/CC coatings to achieve compliance with the topcoat standard of performance is unreasonable due to the economic penalty this could impose on domestic automobile manufacturers as a result of their inability to market vehicles with BC/CC coatings. Similarly, as explained below, the use of add-on controls is also unreasonable.

Up to 80 percent of all VOC's emitted from a topcoat operation are emitted from the spray booth area. This high volume emission stream is characterized by low VOC concentration. This is due to the ventilation requirements for workers in the spray booth and process considerations to prevent overspray from drifting from one vehicle to the next. There are two add-on control technologies that could be applied to this stream to reduce VOC emissions: carbon adsorption and incineration. Both effectively remove or destroy VOC's from the exhaust streams before release to the atmosphere.

Carbon adsorption units have been used in experimental small scale studies on low VOC concentration spray booth exhaust streams and have been technically demonstrated. Although these systems have not been used in

full-scale production, there is sufficient evidence to show that they would also work in such applications. Based on studies conducted at their Fremont, California plant, GM estimated the capital cost for the size carbon adsorption system necessary to achieve compliance with the topcoat standard of performance on a 20/42 BC/CC topcoat system to be $78,000,000 per plant. The annualized operating cost for this system (including labor, depreciation, insurance, taxes, utilities, and carbon) was estimated to be approximately $19 million per plant. The carbon adsorber would remove approximately 1200 tons of VOC emissions per year resulting in a cost-effectiveness of over $15,000 per ton of VOC removed. This is considered excessive.

Incineration of the spray booth exhaust stream requires a large amount of supplemental fuel because the low VOC concentration cannot support combustion by itself. The economic and energy impacts of incineration have been estimated to be significantly higher than the carbon adsorption control alternative outlined above.

In summary, BC/CC topcoat systems which will meet the topcoat standard of performance and allow production of BC/CC coated vehicles at the levels required to permit domestic automobile manufacturers to compete with foreign automobile manufacturers are not adequately demonstrated. Add-on control systems that would reduce VOC emissions to levels required to comply with the topcoat standard of performance are demonstrated technically, but the economic and energy impacts associated with these control systems are considered unreasonable.

BC/CC Systems Will Operate Effectively and Achieve the Standard at Lower Costs

There is sufficient evidence to indicate that the companies that develop and market automobile coatings and coatings application equipment will develop BC/CC coating systems that will meet both the topcoat standard of performance and the automobile manufacturers production and coating quality requirements within the time frame provided in the waivers. This conclusion is based on the fact that a number of BC/CC coatings, which have lower VOC contents than currently demonstrated BC/CC coatings, are already in various stages of testing and that the companies that develop and market automobile coatings have a history of succeeding within their projected time frames for developing low-VOC content coatings.

When developed, the 32/45, 35/55, 38/54, and 48/54 BC/CC topcoat coatings will meet the topcoat standard of performance at lower cost and energy requirements compared to the use of waterborne coatings which are the basis of the topcoat standard of performance. These low-VOC content BC/CC coatings will also be able to achieve the topcoat standard without spray booth controls; therefore, the energy and economic impacts would be much less than for the use of a 20/42, 21/37, or 21/42 BC/CC coating and spray booth controls.

Number of Waivers Needed To Demonstrate Technology

Based on a review of the technical factors involved in demonstrating that lower solvent BC/CC systems are an available technology, the Agency concludes that the number of waivers which have been requested are necessary and appropriate. Generally, much of the BC/CC technology is transferable among automobile manufacturing companies, since coating manufacturers do not limit their sales to only one firm or plant. However, individual automobile manufacturing companies have historically relied on their own testing procedures and acceptance criteria for establishing a coating durability and quality. Such independent testing is an inherent part of the competitive structure of the automobile industry and plays an important role in advancing the quality of automobile coatings.

Moreover, the demonstration of BC/CC technology involves advancement in application equipment as well as the coatings, and the two must be compatible. The advancement and demonstration of this technology must take into account a number of variables including different plant designs and approaches to paint processing; variability among coating supplied by three or more suppliers; plant-to-plant differences in the performance of paint line equipment (e.g. ovens, temperature, and humidity control systems); the use of evolving robot systems; and new high voltage electrostatic equipment supplied by several vendors. In effect, these variables present a matrix of combinations which must be evaluated before the lower solvent BC/CC systems are fully demonstrated. Considering the complexity and technical challenge which this presents, the Agency concludes that each waiver is warranted.

BC/CC Will Not Cause or Contribute to Unreasonable Risk to Public Health, Welfare, or Safety

The ambient air implications of allowing additional VOC emissions during the waiver period would not contribute to an unreasonable risk to public health, welfare, or safety. The waivers would allow between 200 and 1,200 additional tons of VOC per plant per year to be emitted from topcoat operations while they are in effect. All five plants are in non-attainment areas for ozone. Each plant, however, must obtain State permits prior to construction. These permits must insure that reasonable further progress toward attainment will be achieved. Therefore, the proposed waivers would not prevent attainment and maintenance of the national ambient air quality standard for ozone. Each of the five plants must also meet the lowest achievable emission rate (LAER) requirement of section 173 of the Act.

Use of the low-VOC content BC/CC coating systems will not result in an increase in water or solid waste pollution compared to the current coating systems now in use at existing plants, nor will new pollutants be released to the environment.

Conclusion

Based on the above considerations, the Administrator proposes to grant, subject to the concurrence of the Governors of Michigan, Missouri, Ohio, and Tennessee, innovative technology waivers as specified in this proposal to: (1) GM for their Wentzville, Missouri automobile assembly plant; (2) GM for their Detroit, Michigan automobile assembly plant; (3) GM for their Orion Township, Michigan automobile assembly plant; (4) Honda for their Marysville, Ohio automobile assembly plant; and (5) Nissan for their Smyrna, Tennessee light-duty truck assembly plant; based upon findings that such waivers comply with the provision of Section 111(j) of the Act.

Proposed Waivers

The five waivers are proposed to be granted under the followed general conditions. The starting BC/CC system would be the lowest emitting BC/CC system adequately demonstrated for each plant. The plants must use coating applications systems with the highest transfer efficiencies that are currently available and practical at the respective plant.

The waivers will cover only the BC/CC metallic topcoat portion of the topcoat operations. If single coat solid color or metallic topcoats are used, the

portion of the topcoat operation must meet the topcoat standard of performance at all times. Reports of progress on the development of the BC/CC systems must be made to EPA within 60 days of start-up and at least once each 12-month period. The topcoat standard of performance must be achieved as soon as possible. Each waiver will not exceed a period of 4 years from the start-up date of the plant, nor will it go beyond December 31, 1986.

The companies are required, consistent with Section 173 of the Clean Air Act, to obtain permits to operate from the State. These permits will assure that each plant granted a waiver will not prevent attainment and maintenance of any national ambient air quality standard. The conditions of the proposed waiver would also require proper operation of the BC/CC systems.

By virtue of Section 111(j)(1)(B) of the Act, 42 U.S.C. 7411(j)(1)(B), the terms and conditions of the Section 111(j) waivers would be federally promulgated standards of performance legally applicable during the waiver periods. Violations of the terms and conditions of the Section 111(j) waivers would subject the owners and operators of the plants granted waivers to Federal enforcement under Section 113 (b) and (c), 42 U.S.C. 7413 (b) and (c), and 120, 42 U.S.C. 7420 of the Act, as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

State Concurrence

Pursuant to Section 111(j)(1)(A) of the Act, 42 U.S.C. 7411(j)(1)(A), if after review and consideration of comments submitted in response to this rulemaking, the Administrator decides to issue a waiver of the Federal new source performance standard to the GM Detroit, Michigan plant; GM Wentzville, Missouri plant; GM Orion Township, Michigan plant; Honda Marysville, Ohio plant; and Nissan Smyrna, Tennessee plant; the Administrator shall request the concurrence of the Governors of the States of Michigan, Missouri, Ohio, and Tennessee. Receipt of such concurrences is a prerequisite for a waiver under Section 111(j) of the Act.

Docket

The docket for each proposed waiver is an organized and complete file of all the information considered in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking process. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated waivers and EPA's responses to significant comments, the contents of the docket will serve as the record in case of judicial review except for interagency review materials [Section 307(d)(7)(A)].

Miscellaneous

In accordance with Section 117 of the Act, publication of these proposed waivers was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

The Paperwork Reduction Act of 1980 (PL 96-511) requires EPA to submit to the Office of Management and Budget (OMB) certain public reporting/recordkeeping requirements before proposal. This rulemaking does not involve a "collection of information" as defined in the Paperwork Reduction Act. Therefore, the provisions of the Paperwork Reduction Act applicable to collection of information do not apply to this rulemaking.

The Administrator certifies that a regulatory flexibility analysis under 5 U.S.C. 601 et seq. is not required for this rulemaking because the rulemaking would not have a significant impact on a substantial number of small entities. The rulemaking would not impose any new requirements; and, therefore, no additional costs would be imposed. It is, therefore, classified as nonmajor under Executive Order 12291.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment, Disposal and Zinc.

Dated: July 29, 1982.

John W. Hernandez, Jr.,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Title 40 Part 60, Subpart MM of the Code of Federal Regulations is proposed to be amended by adding a new § 60.398 as set forth below:

§ 60.398 Innovative technology waivers.

(a) General Motors Corporation, Wentzville, Missouri Automobile Assembly plant.

(1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation automobile assembly plant located in Wentzville, Missouri, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Wentzville assembly plant.

(ii) Commencing on —— [date of promulgation in the Federal Register], and continuing for 4 years or to December 31, 1986, whichever comes first, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, the General Motors Corporation shall limit the discharge of VOC emissions to the atmospere from each topcoat operation at the Wentzville, Missouri assembly plant, to either:

(A) 3.2 kilograms of VOC per liter of applied coating solids from base coat/clear coat metallic topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solid from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat metallic coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(a)(1)(ii)(A).

(v) A technology development report shall be sent to EPA Region VII, 324 East 11th Street, Kansas City, Missouri 64106, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a federally promulgated standard of performance.

As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412 (b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(b) General Motors Corporation, Detroit, Michigan Automobile Assembly plant.

(1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation's automobile assembly plant located in Detroit, Michigan, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Detroit assembly plant.

(ii) Commencing on——[date of promulgation in the Federal Register], and continuing for 4 years or to December 31, 1986, whichever comes first, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, the General Motors Corporation shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Detroit, Michigan assembly plant, to either:

(A) 3.2 kilograms of VOC per liter of applied coating solids from base coat/clear coat metallic topcoats, and 1.47 kilograms of VCC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solid from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear metallic coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(b)(1)(ii)(A).

(v) A Technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a federally promulgated standard of performance. As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113(b) and (c), 42 U.S.C. 7412(b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(c) General Motors Corporation, Orion Township, Michigan automobile assembly plant.

(1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation automobile assembly plant located in Orion Township, Michigan, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Orion Township assembly plant.

(ii) Commencing on—— [date of promulgation in the Federal Register], and continuing for 4 years or to December 31, 1986, whichever comes first, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, the General Motors Corporation shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Orion Township, Michigan, assembly plant, to either:

(A) 3.2 kilograms of VOC per liter of applied coating solids from base coat/clear coat metallic topcoats, and 1.47 kilograms of VCC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solid from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear metallic coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(c)(1)(ii)(A).

(v) A Technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a federally promulgated standard of performance. As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412 (b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(d) Honda of America Manufacturing, Incorporated (Honda), Marysville, Ohio, automobile assembly plant.

(1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at Honda's automobile assembly plant located in Marysville, Ohio shall comply with the following conditions:

(i) Honda shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Marysville assembly plant.

(ii) Commencing on —— [date of promulgation in the Federal Register] and continuing for 4 years or to December 31, 1988, whichever comes first, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, Honda shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Marysville, Ohio, assembly plant, to either:

(A) 3.1 kilograms of VOC per liter of applied coating solids from base coat/

clear coat metallic topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solid from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat metallic coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(d)(1)(ii)(A).

(v) A technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a federally promulgated standard of performance. As such, it shall be unlawful for Honda to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject Honda to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412 (b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(e) Nissan Motor Manufacturing Corporation, U.S.A. (Nissan), Smyrna, Tennessee light-duty truck assembly plant.

(1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at Nissan's light-duty truck assembly plant located in Smyrna, Tennessee shall comply with the following conditions:

(i) Nissan shall obtain the necessary permits as required by Section 173 of the Clean Air Act as amended August 1977, to operate the Smyrna assembly plant.

(ii) Commencing on —— [date of promulgation in the Federal Register], and continuing for 4 years or to December 31, 1986, whichever comes first, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, Nissan shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Smyrna, Tennessee assemply plant, to either:

(A) 2.3 kilograms of VOC per liter of applied coating solids from base coat/clear coat metallic topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solid from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat metallic coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(e)(1)(ii)(A).

(v) A technology development report shall be sent to EPA Region IV, 345 Courtland Street, N.E., Atlanta, Georgia 30365, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a federally promulgated standard of performance. As such, it shall be unlawful for Nissan to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject Nissan to enforcement under Section 113(b) and (c), 42 U.S.C. 7412(b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

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Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2070-5(a)]

Standards of Performance for New Stationary Sources; Industrial Surface Coating—Large Appliances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance to limit emissions of volatile organic compounds (VOC's) from new, modified, and reconstructed surface coating operations within large appliance assembly plants. The standard was proposed in the **Federal Register** on December 24, 1980 (45 FR 85085). This standard implements Section 111 of the Clean Air Act and is based on the Administrator's determination that the surface coating of large appliances causes, or contributes significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare. The intended effect of this standard is to require all new, modified, and reconstructed large appliance surface coating operations to control emissions to the level achievable through use of the best demonstrated system of continuous emission reduction, considering costs, non-air-quality health, and environmental and energy impacts.

EFFECTIVE DATE: October 27, 1982.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard (NSPS) is available *only* by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES:

Background Information Document. The background information document (BID) for the final standard may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Industrial Surface Coating: Large Appliances—Background Information for Promulgated Standards" (EPA-450/3-80-037b). The BID contains (1) a summary of all public comments made on the proposed standard and the Administrator's responses to the comments; (2) a summary of changes made to the standard since proposal; and (3) the final environmental impact statement (EIS), which summarizes the impacts of the standard.

Docket. A docket, number A-80-06, containing support information used in developing the promulgated standard, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Chief, Standards Preparation Section, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5624.

SUPPLEMENTARY INFORMATION: OMB Control Number: 2000-0473

The Standard

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> • • • application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standard applies to new, modified, or reconstructed large appliance surface coating operations for which construction was commenced after December 24, 1980. Existing facilities are not subject to the regulation unless modified or reconstructed as defined in 40 CFR 60.14 or 60.15. The standard, as revised since proposal, applies to each prime coat and each topcoat operation within a large appliance assembly plant where large appliance parts are being coated with organic coatings. Powder coatings, however, are excluded from the definition of organic coatings. VOC emissions from each affected facility are limited to a monthly average of 0.90 kilogram per liter of applied coating solids. An affected facility is defined as a surface coating operation that consists of an application station(s), flashoff area(s), and a curing oven. Coating operations for any of the following organic surface-coated metal products manufactured for household, commercial, or recreational use are subject to the standard:

Range	Washer
Oven	Dryer
Microwave oven	Dishwasher
Refrigerator	Water heater
Freezer	Trash compactor

BDT for this industry has been determined to be the application of a coating containing 62 percent by volume of solids at a transfer efficiency of 60 percent with an assumed solvent density of 0.88 kg/l. The regulation, however, permits tradeoffs between these variables. In other words, an owner or operator using application equipment with a higher transfer efficiency may use a coating with a correspondingly lower solids content. Compliance can also be achieved by the use of coatings with an average organic-solvent content that, in conjunction with any capture system and control device operated at the reduction efficiency demonstrated during the most recent performance test, limits emissions to 0.90 kg/l of applied coating solids.

Following the initial 1-month performance test, the owner or operator must calculate and record the VOC emissions from each affected facility for each calendar month. Each monthly calculation is considered a performance test. Information necessary to perform the monthly calculation can be obtained from company records and data supplied by the coating manufacturer or by an analysis of the coating by Reference Method 24. Equations and transfer efficiencies for calculating the emissions for each affected facility are provided in the standard. Reference Method 25 will be used to determine the VOC concentration in a gas stream. This method in conjunction or combined with Reference Methods 1, 2, 3, and 4 will be used to determine the percentage reduction of VOC emissions achieved through use of a capture system and control system.

Recordkeeping requirements include those data necessary to substantiate the monthly calculations of emissions. These data must be retained at the source for a period of 2 years. The regulation contains no reporting requirements in addition to those required by the General Provisions of 40 CFR Part 60 relative to the initial performance test.

Environmental, Energy, and Economic Impacts

In 1980 it is believed that there were a total of 59 companies operating 104 facilities engaged in the production of large household appliances. Although plants are widely dispersed throughout 25 States, industry production is concentrated in the Midwestern and

Midsouthern States. It is estimated that the standard will apply to approximately 160 new, modified, or reconstructed surface coating operations (40 plants) by 1986.

Environmental, energy, and economic impacts of standards of performance are normally expressed as incremental differences between a facility complying with the proposed standard and a facility complying with a typical State implementation plan (SIP) emission standard. Most existing large appliance surface coating operations are in localities that are considered nonattainment areas for achieving the national ambient air quality standard (NAAQS) for ozone. New facilities are expected to locate in similar areas. At the time the emissions estimates in the BID for the proposed standard were prepared, SIP's were being revised for these areas. In revising their SIP's, most States were relying upon the control techniques guideline (CTG) document, "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume V: Surface Coating of Large Appliances" (EPA–450/2–77–034[CTG]). It appeared that most States were adopting the CTG recommendations statewide, in attainment as well as in nonattainment areas. For this reason, no distinction was made between the "no additional regulation" alternative and the alternative eventually selected as BDT. Both were based upon 62 percent (volume) solids coatings, and the transfer efficiency incorporated into the BDT alternative was an estimate of the average transfer efficiency actually achieved in the industry. Therefore, in the documents supporting the proposed standard, the emissions reduction attributable to the NSPS was reported as "minimal."

Now that the majority of SIP revisions have been approved, the emissions estimates have been refined. A recent analysis that is documented in the BID for the final standard indicates that 89 percent of the known large appliance manufacturing plants are located in nonattainment areas or in attainment areas where the emissions limits are at least as strict as those recommended by the CTG. If the projected growth in the industry is accommodated through plants subject to the NSPS distributed geographically in the same manner as existing plants (rather than through increased use of existing capacity), it is estimated that the standard will reduce nationwide VOC emissions by approximately 700 metric tons per year by 1986.

Standards of performance have other benefits in addition to reducing emissions beyond the requirements of a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation that reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. Costs are provided in an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact of controls on an industry.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well-publicized national forum to reach a decision on a pollution emission level that allows a dynamic economy and a healthful environment.

Surface coating operations in a typical large appliance assembly plant consume 73,000 GJ of energy a year. Because no new coatings, application methods, or control devices will be required, this standard will have no discernible impact on energy consumption in the large appliance industry.

Although growth through the next few years will probably be dampened by inflation, it is predicted that the large appliance industry will continue to experience steady, if minimal, overall growth. As in previous years, industry growth is expected to be confined to major manufacturers. The acquisition trend is also expected to continue as small manufacturers, unable to compete with mass producers, become prime candidates for acquisition. Although inflationary pressures are expected to increase industrywide prices during the next few years, price increases are expected to remain minimal.

Surface coating operations in a typical large appliance assembly plant represent a capital investment of almost $3 million. Annual direct operating costs are approximately $1.8 million. Because no new coatings, application methods, or control devices will be required, it is estimated that the standard will have no discernible impact on capital or operating costs of new surface coating operations within large appliance assembly plants. For the same reasons, no impact on product price is anticipated. The standard's impact on water pollution and solid waste disposal will also be minimal.

Detailed analyses of the regulatory alternatives and the environmental, energy, and economic impacts of the standard of performance were originally presented in "Industrial Surface Coating: Appliances—Background Information for Proposed Standards" (EPA–450/3–80–037a) and remain unchanged since proposal.

Public Participation

Prior to proposal of the standard, interested parties were advised by public notice in the **Federal Register** (45 FR 30686, May 9, 1980) of a meeting of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) to discuss the standard for appliance surface coating operations recommended for proposal. Held on June 5, 1980, the meeting was open to the public and each attendee was given an opportunity to comment on the standard recommended for proposal. The standard was proposed and published in the **Federal Register** on December 24, 1980 (45 FR 85085). The preamble to the proposed standard discussed the availability of the BID, "Industrial Surface Coating: Appliances—Background Information for Proposed Standards" (EPA–450/3–80–037a), which describes in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at that time and copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on January 28, 1981, at Research Triangle Park, North Carolina. The hearing was open to the public and each attendee was given an opportunity to comment on the proposed standards. Written comments were accepted throughout the comment period, which extended from December 24, 1980, to February 23, 1981.

Twenty-one comment letters were received and three interested parties testified at the public hearing concerning issues relative to the proposed standard

of performance for the appliance surface coating source category. The comments have been carefully considered and, where determined to be appropriate, changes have been made in the proposed standard.

Significant Comments and Changes to the Proposed Standard

Comments on the proposed standard were received from the appliance industry, the coatings industry, Federal agencies, one State and one local air pollution control agency, and two trade associations. Although a number of changes have been made in the standard since proposal, the affected facilities, control techniques on which the standard is based, and impacts remain as presented in the BID for the proposed standard. A detailed discussion of the comments and responses can be found in the BID for the promulgated standard. Most comment letters contained multiple comments. Major comments and responses are summarized in this preamble and have been divided into the following areas: General, Emission Control Technology, and Reporting and Recordkeeping.

General

This standard was proposed as an appliance surface coating standard that included several appliances not traditionally considered to be large household appliances, the category that appeared on the priority list of major source categories for which EPA is to promulgate NSPS. These other products had been added for reasons to be enumerated below, and a proposal to amend the priority list to include all appliances regardless of size was published in the Federal Register (45 FR 85099) concurrently with the proposal of the standard (December 24, 1980).

Several commenters said that the numerous small appliances manufactured by the home ventilating industry should not be covered by the appliance standard because the home ventilating industry and large appliance industry use different types of coatings and application equipment and have different manufacturing environments. Line speeds in large appliance manufacturing plants are faster, and coating operations of the two industries are not similar. Large appliance manufacturing plants make one or two products using a two-coat system, while home ventilating plants make a wide variety of products using a single-coat system. The coating technology is not as advanced in the small shops making the small appliances, and the existing small appliance coating application equipment does not approach the 60-percent assumed average transfer efficiency for large appliances. Failure to recognize these differences will allow unfair advantage to a few industries.

One company further commented that its range hoods are coated with a single-coat, modified alkyd baking enamel formulated for a hot, grease-laden environment. Specifications for this coating differ from specifications for acrylic coatings used in the large appliance industry. Another commenter stated that the available high-solids coatings were inadequate for coating irregularly shaped objects like range hoods and fans. Compliance coatings are reasonably available for the five major appliance colors but are not reasonably available for the other thirteen colors and color combinations used for range hoods. According to this commenter, while approaches to the development of new low-solvent coatings and new, efficient application systems for home ventilating products show promise [waterborne and high-solids coatings; exempt solvents, powder coatings, and electrodeposition (EDP)], they are still in the experimental stage.

The commenters continued that although much of the coating equipment used in the home ventilating industry is similar to that used in the large appliance industry, distinct shape differences for some parts make spinning disc electrostatic equipment, which is common in the large appliance industry, impractical for coating range hoods with high-solids coatings. Small appliance application coating equipment, like large appliance application equipment, will have to undergo modification before high-solids coatings are used.

As the commenters reported, often in the home ventilating industry, parts of several appliance products are coated on the same line. As different standards might then exist for different products, productivity would suffer while the line was changed to comply with whatever standards might apply to the units being coated. If the most stringent standard were used for all products coated on this hypothetical line, those not covered (but coated in compliance, nevertheless) may not be able to remain competitive with products made by manufacturers who did not have to comply. Different standards might also apply to different lines within a plant. One of the commenters stated that because of time constraints and limited resources, he was unable to provide complete cost information on the range hood/fan segment of the industry, and, therefore, only noted that the model plants used in the economic analysis are not typical of this segment of the industry.

Comments of a similar nature concerning the availability of high-solids coatings in many colors and the differences in coating operations were also received from one manufacturer of refrigerated display cases.

Based upon the comments received, EPA has determined that in the absence of additional analysis and study, it is inappropriate to conclude that BDT for the manufacture of traditional large appliances also applies to the manufacture of other appliances. The majority of data upon which the proposed standard was developed pertained to the surface coating of traditional household appliances such as ranges, microwave ovens, ovens, refrigerators, laundry equipment, and freezers. This information is contained in the BID for the proposed standard. The decision to regulate 17 other appliance products (range hoods, refrigerated display cases, dry cleaning equipment, water softeners, interior lighting fixtures, vacuum cleaners, ice makers, air purifiers, baseboard heaters, room heaters, humidifiers, dehumidifiers, fans, furnaces, window air conditioners, unitary air conditioners, and heat pumps) was made subsequent to development of the majority of the background information. This decision was made because the coating application methods appeared to be identical to those used in large appliance coating operations and because the coating materials and performance specifications also appeared to be similar to those used in the large appliance industry. Therefore, there appeared to be no technical reason to exclude these other appliance products. As a result of the reevaluation prompted by these comments, the entire group of 17 other appliance products listed above has been deleted from the standard. This is not to imply that none of these industries can achieve the levels of control required by this standard. This or even more stringent requirements may be appropriate in the application of BACT or LAER.

In addition, the Administrator has concluded from these comments that further examination of such factors as projected growth and applicable emission limits for other segments of the appliance coating industry are necessary before concluding that these other appliance coating operations contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Therefore, the Agency is withdrawing the proposed amendment to aggregate

all appliance surface coating operations into one source category on the priority list. An announcement to this effect appears elsewhere in this issue of the Federal Register.

One commenter stated that one company in its corporation uses an aluminum-based coating on gas furnace parts that are subject to very high temperatures (1,000° F) and may use similar coatings on certain parts of gas dryers and water heaters. While the coating solids are inorganic, the material is spray applied with an organic carrier that yields organic-solvent emissions. A question existed as to whether this coating would be considered an "organic coating." If so, it would not meet the standard nor would any other temperature-resistant coating known to the commenter.

Although an "organic coating" was not defined explicitly in the proposed standard, EPA considers any coating that yields VOC emissions to be organic. For clarification, a definition of an "organic surface coating" has been added in § 60.451 of the final regulation. In addition, the specific problem raised by the commenter is corrected in the final version of the standard by incorporating a temperature cutoff in the regulation. After several industry representatives were consulted, 250° F was selected as the cutoff because coatings required to withstand heat in excess of this temperature are difficult, if not impossible, to formulate at the 62-percent (volume) solids level. The coating of appliance parts that are subject to in-use temperatures above 250° F, therefore, is not subject to the emission limitations in this standard.

One commenter noted that key operating parameters of application equipment should be checked regularly to ensure that equipment is being operated in accordance with manufacturers' specification. These checks could be performed at the same time monthly determinations of VOC emissions compliance are made. It was recommended that the Agency encourage operator training by offering an incentive in the form of additional transfer efficiency credits for firms that have operator training programs.

Proper operation and maintenance of facilities is required in § 60.11(d) of the General Provisions of 40 CFR Part 60. Therefore, improper operation or emission excesses resulting from improper operator training would be considered a violation of § 60.11(d). Although EPA certainly encourages industry to provide adequate training for its spray equipment operators, a mechanism to "credit" operator training is not within the scope of EPA's regulatory development program. The training program's adequacy would have to be monitored, and the implementation and enforcement requirements are considered to be excessive. Decreases in coating use, part rejection, and maintenance are major economic incentives for a company to implement an operator training program. The Agency believes these reasons are sufficient to ensure proper operation and maintenance of application equipment.

Three commenters noted that technical requirements for surface coating of wood stoves, furnaces, and room heaters are not similar to large appliances in that high temperature requirements preclude the use of water-based coatings. High-solids coatings are also not available to meet these performance specifications. Consequently, wood stoves, furnaces, and room heaters should be classified as miscellaneous metal parts and products with extreme performance characteristics and should not be covered in this regulation.

Wood stoves and direct-fired room heaters were never intended to be included in this regulation. Although one commenter indicated successful testing of a coating that could achieve the proposed emission limit, EPA does not have sufficient data to conclude that such coatings have been adequately demonstrated. Because the coating of large appliance parts exposed to extreme temperatures was not intended to be subject to the proposed standard, the definition of large appliance parts to be covered by this regulation has been clarified. In addition, furnaces and room heaters have been excluded from the list of products to be covered by this regulation.

One commenter expressed concern that the proposed standard was unduly restrictive in that it did not allow use of the "bubble concept," whereby credit for overcompliance on one line could be used to offset use of noncompliance coatings on another line. Other commenters stated that many firms manufacturing smaller appliances finished several products on a single line.

The "bubble concept" refers to application of a standard to an entire plant rather than to separate portions of an individual plant. The term "affected facility" refers to the particular portion of a plant to which a standard applies. In this case the affected facility has been defined as a surface coating operation, which consists of a coating application station(s), flashoff area(s), and an oven. The choice of the affected facility for any standard is based on the Agency's interpretation of the Clean Air Act, as amended, and judicial construction of its meaning. Under Section 111, the NSPS must apply to "new sources;" a "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" [Section 111(a)(3)]. Most industrial plants, however, consist of numerous pieces or groups of equipment that emit air pollutants and that might be viewed as "sources." EPA uses the term "affected facility" to designate the equipment, within a particular kind of plant, that is chosen as the "source" covered by a given standard.

In choosing the affected facility, EPA must decide which pieces or groups of equipment are the appropriate units for separate emission standards in that particular industrial context. One major consideration in this decision is that use of a narrower definition brings replacement equipment under the NSPS sooner. If, for example, an entire plant were designated the affected facility, no part of the plant would be covered by the standard unless the plant as a whole were "modified." If, on the other hand, each piece of equipment were designated the affected facility, as each piece were replaced, the replacement piece would be a new source subject to the standard. Since the purpose of Section 111 is to minimize emissions by the application of the best demonstrated control technology (considering cost, other health and environmental effects, and energy requirements) at all new and modified sources, there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources within plants will be brought under the coverage of the standards as they are installed. This presumption can be overcome, however, if the Agency concludes that the relevant statutory factors (technical feasibility, cost, energy, and other environmental impacts) point to a broader definition. As shown in the BID, it is both technologically and economically feasible to control each coating operation. Since selecting this narrowest definition of the affected facility would achieve the greatest emission reduction, this definition is most consistent with the purposes of Section 111.

Two other possible definitions of the affected facility in this standard are all prime coat (or topcoat) operations in a product line and all prime coat (or topcoat) operations within an assembly plant. The product line definition would have reduced the number of affected facilities and would have permitted tradeoffs between different coatings and

application technologies. Likewise, defining all prime coating (or topcoating) operations within a plant as the affected facility would have reduced the number of affected facilities and, consequently, the associated recordkeeping and compliance calculations. However, such definitions would not necessarily result in either the use of best technology or the minimization of emissions from new sources. For these reasons, the Agency has chosen each surface coating operation as the affected facility.

The specific concern from small appliance manufacturers who finish several products on a single line that different standards would apply to different products on the same coating line is no longer applicable since manufacturers of these products are not subject to the promulgated standard. The Agency is not aware of any large appliance manufacturers finishing several products on a single line who might encounter this situation.

One commenter opposed implementation of the proposed standard at this time because he considered additional regulations unnecessary and overly burdensome and thought industry deserves to be advised of the real need for VOC standards more stringent than those now imposed.

Standards of performance are promulgated under Section 111 of the Clean Air Act. Section 111(b)(1)(A) requires that the Administrator establish standards of performance for categories of new, modified, or reconstructed stationary sources that in his judgment cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Standards of performance prevent new air pollution problems from developing by requiring application of the best technological system of continuous emission reduction that the Administrator determines to be adequately demonstrated. The 1977 Amendments to the Clean Air Act added the words, "in the Administrator's judgment," and the words, "may reasonably be anticipated," to the statutory test. The legislative history for these changes stresses two points:

- The Act is preventive, and regulatory action should be taken to prevent harm before it occurs; and
- The Administrator should consider the contribution of each single class of sources to the cumulative impact of all VOC emitters.

The 1977 Amendments to the Clean Air Act also required that the Administrator promulgate a priority list of source categories for which standards of performance are to be promulgated. The priority list, 40 CFR 60.16, was promulgated in the Federal Register on August 21, 1979 (44 FR 49222). Development of the priority list was initiated by compiling data on a large number of source categories from literature resources. Major stationary source categories were then subjected to a priority ranking procedure using the three criteria specified in Section 111(f) of the Act. The procedure ranks source categories on a pollutant-by-pollutant basis. In this ranking, first priority was given to the quantity of emissions, second priority was given to the potential impact on health or welfare, and third priority was given to the mobility and competitive nature of the source category.

In light of the considerations stated above, the Administrator found that the large appliance coating industry is a "significant contributor." (Applying the criteria for prioritizing such contributors, the Administrator ranked the surface coating of large appliances 28th of 59 source categories on the priority list.) This listing decision requires the Agency to promulgate standards of performance for new sources in this category.

Another study was conducted to investigate the large appliance surface coating industry in more detail. This study resulted in development of the BID, which specifically addressed the industry in terms of structure, processes, and emission control techniques. The BID also described modification and reconstruction; alternative regulatory options; and the environmental, economic, and energy impacts that would be associated with implementing each of the various regulatory options. During this study it was estimated that a minor reduction in emissions would result from the proposed regulation, primarily because of improvements already achieved by State regulations. A more recent study, however, estimated that the standard would reduce nationwide VOC emissions by 700 metric tons per year by 1986. This new study is documented in the BID for the final standard. The regulation has other benefits in addition to reducing emissions beyond those required in State regulations. The transfer efficiency concept incorporated in this regulation was not included in the CTG document issued to the States. Its inclusion here is a major benefit because specifying an emissions limit based upon a specific VOC content and a specific transfer efficiency automatically incorporates an equivalency provision into the regulation and allows tradeoffs between VOC content and transfer efficiency. That is, an operator using application equipment with a high transfer efficiency could use a coating with a higher VOC content. Such a provision also enables the diverse coatings and application techniques within the industry to be accommodated by a single standard.

Also, standards of performance establish a degree of national uniformity, which precludes situations in which some States may attract industries by relaxing air pollution standards relative to other States. They improve the efficiency of case-by-case determinations of BACT for facilities located in attainment areas and LAER for facilities located in nonattainment areas, by providing a starting point for the basis of these determinations. This starting point results from the process of developing a standard of performance, which involves comprehensive analysis of alternative emission control technologies and evaluation and verification of emission test methods.

For these reasons, VOC emissions from large appliance surface coating operations have been selected for regulation under an NSPS.

Emission Control Technology

One of the commenters stated that the generic classifications of equipment in Table 1 (Section 60.453) are poorly defined and inappropriate. The Agency's listing of transfer efficiencies for generic equipment will encourage the use of lower priced, inferior equipment that does not perform as well as the Agency has indicated. The listing will also discourage use of equipment that presently exceeds listed values, since added credit may be difficult to obtain. For this reason, the Agency's estimates of emission reductions are overstated and the objectives will not be met. The commenter suggested that a standardized test method be adopted to determine transfer efficiency. Equipment could then be "certified" by the manufacturer and a list of equipment ratings and operating conditions could be supplied to EPA for publication. The equipment operator should be required to use these published transfer efficiencies to determine compliance.

The promulgated standard will significantly benefit users of equipment that has a high transfer efficiency because of the flexibility of coating selection it will afford. Incorporation of the transfer efficiency concept into this standard is one of the main improvements over earlier RACT guidelines and existing State regulations because existing regulations do not give credit for transfer efficiency. With this

regulation, due credit will be given to users of more efficient equipment.

EPA recognizes that the actual transfer efficiency achieved in production line situations depends on a large number of variables. It was this difficulty in determining transfer efficiency values that caused EPA to use the table of assigned numbers. Any improvement in the efficiency at which coatings are applied will benefit both the EPA's goal of reducing VOC emissions and the industry's goal of achieving more economical operation. A more detailed listing of transfer efficiency values would require a uniform test method for all situations. Such a method has not yet been developed but is under investigation by EPA's Industrial Environmental Research Laboratory (IERL). The Agency does not believe the listed transfer efficiencies will promote the use of inferior equipment because operating cost advantages, such as decreased coating usage, will dictate the use of efficient equipment and encourage its proper operation.

Several commenters stated that the proposed standard was inequitable because the concept of assumed transfer efficiency did not account for the following parameters:

- Part configuration,
- Type of coating,
- Solids level,
- Resin type,
- Flow rate,
- Operator efficiency,
- Local environmental conditions,
- Charging voltages, and
- Interaction of all of the above variables with each type of application equipment.

Two of these commenters suggested that spray equipment manufacturers had not had adequate opportunity to suggest an appropriate test method to determine actual transfer efficiency that could be incorporated into the standard. It was suggested that the National Spray Equipment Manufacturers Association (NSEMA) coordinate industry responses on transfer efficiency. Exception was taken to NSEMA not being contacted during development of this standard.

No changes were made in the regulation as a result of these comments. EPA believes that to reflect BDT for the large appliance coating industry, emission limits for new sources must incorporate the use of both high-solids coatings and relatively efficient application equipment but must not at the same time deny industry flexibility to use different types of application equipment and different coatings. For this reason, the Agency has included the key transfer efficiency concept in this standard.

The commenter's claim that all the listed parameters affect transfer efficiency is correct. However, a universally acceptable test method for determining precise transfer efficiency under each conceivable set of variables has not yet been developed. This means that the Agency must either delete this crucial component of BDT or instead include in the standard assigned transfer efficiency values that correlate at least generally to the efficiencies of the application equipment used in the industry. EPA has chosen the latter course. The Agency has included values that are correlated to each piece of equipment and are sufficiently high to ensure that, regardless of coating properties and other relevant variables, each facility will be credited with at least the efficiency its equipment attains with the particular coatings it applies. These transfer efficiencies listed are based on data provided by spray equipment manufacturers and results of tests conducted during standard development. EPA contacted and visited several equipment and coatings manufacturers during the standard development process. Summaries of these contacts are contained in Docket Category II–E.

Moreover, the standard provides that if the operator can demonstrate to the satisfaction of the Administrator that other transfer efficiencies are appropriate (e.g., due to variables such as those cited in the comment), the Administrator will approve their use on a case-by-case basis. This provision ensures that a facility using equipment that achieves an efficiency greater than that assigned by the standard is fully credited for the efficiency achieved.

One commenter noted that the potential for cost effectiveness and overall performance of regenerative thermal oxidation systems was not included in background documentation for the proposed standard. A system designed by this company is said to be capable of providing primary heat exchange efficiencies of up to 95 percent in the thermal oxidation process. The high thermal energy recovery of this system allows operation in a self-sustaining mode of hydrocarbon contents of from 3 to 5 percent of the lower explosive limit (LEL). Little or no additional fuel is required. This system virtually eliminates the following problem areas generally associated with incineration systems:

- Fouling of heat transfer surfaces,
- Corrosion,
- Catalyst poisoning,
- Secondary emissions, and
- High operating costs with low LEL gas streams.

The commenter requested clarification of the potential of regenerative thermal oxidation systems in the documentation for the promulgated standard.

Regulatory Alternative B–III, outlined in Chapter 6 of the BID for the proposed standard, presents EPA's analysis of incineration of the topcoat exhaust. The analysis reveals that this option has a significantly greater capital investment and an increase in energy consumption over other options. Although the annual operating costs and energy use of a regenerative thermal oxidation system may be lower, initial capital investment is large compared to that for low-solvent coatings technology. Reduction in total organic-solvent emissions realized by controlling the topcoat oven exhaust is small because only 20 percent of these emissions are concentrated in the oven. The remaining 80 percent of the emissions are fugitives from the application and flashoff areas. The small percentage of emissions available for reduction by incineration makes any incinerator difficult to cost justify when compared to low-solvent coatings. For this reason and others set forth in the preamble to the proposal, EPA has decided to base the standard on low-solvent processes, rather than on incineration. Therefore, EPA does not consider necessary further clarification of the potential of regenerative thermal oxidation systems in the documentation for the promulgated standard.

Reporting And Recordkeeping

A comment received during development of another surface coating standard that is considered applicable to large appliance surface coating indicated that the 10-calendar-day period within which violations of the standards must be reported was insufficient to permit the coordination and clearances required to notify EPA of a violation.

As a result of this comment and others, EPA has been investigating alternative ways of reducing monitoring, recordkeeping, and reporting burdens on owners and operators. The goal is to reduce all recordkeeping and reporting not essential to determining compliance or to ensuring proper operation and maintenance. After reviewing requirements in the proposal, EPA determined that monthly compliance tests, monitoring, and compilation of monitoring data are essential for both the owner or operator and EPA to determine compliance and to ensure proper operation and maintenance. A

responsible owner or operator would need monitoring information compiled in a usable form to determine when adjustments in the control system are needed to ensure that it is performing at its intended effectiveness level.

EPA is therefore requiring only the additional step of filing the information in an accessible location. Because EPA judges that monthly compliance tests, monitoring, and recordkeeping are essential for determining compliance and proper operation and maintenance, these requirements have not been changed since proposal. It was judged, however, that reporting is not essential to EPA. In addition, when States are delegated the authority to enforce this standard, they may prefer either not to have reporting or to have reporting on a different schedule than EPA proposed. Therefore, the requirement to report violations of the standard and quarterly incineration reports has been removed since proposal. A State, however, at any time is free to impose its own reporting requirements in conjunction with this regulation.

Another commenter expressed concern over the time a facility would need for recordkeeping and reporting to determine monthly compliance as proposed in the regulation and stated that an added overhead burden would be placed on the industries that ultimately would be passed on to the consumer. Another commenter estimated that it would probably require one person per year at each affected plant, considerably more than estimated in the preamble.

As stated in the previous response, the requirement to report violations of monthly compliance tests has been removed since proposal. In the preamble to the regulation it was estimated that in the fifth year of applicability the promulgated regulation would apply to 50 affected facilities and over these 5 years would require about 40 industry person-years for recordkeeping and reporting. This amounts to about 1 person-month per affected facility per year. (This information is contained in a Reports Impact Analysis, Docket Entry II–I–20. Because all reporting requirements except for the initial performance test results have been eliminated from the standard, and because of the requirement to estimate the Agency resources needed for observing performance tests and for litigation, the Reports Impact Analysis has been revised since proposal. It is now estimated that the industry burden for recordkeeping and reporting will be 28 person-years over the first 5 years of applicability.) Information a manufacturer needs to keep on a day-to-day basis to determine compliance with this standard includes volume of coating used and volume of dilution solvent used. These data are normally kept by companies to provide adequate stock room balances of needed supplies. The other item of information needed to determine compliance, the fraction of solids in the coating, can be obtained from the coating manufacturer. The recording of these data is needed by both the owner/operator and EPA to determine that the source is in compliance. EPA considers the lower time estimates in the Reports Impact Analysis to be reasonably accurate. Therefore, the Agency does not consider the recordkeeping, which is necessary to determine compliance, an unreasonable burden.

Information Requirement Impacts

Reporting and recordkeeping requirements of this regulation are assessed in a Reports Impact Analysis. A copy of this analysis, which considers various alternatives and impacts, is included in the docket for public review. Please reference Subcategory II–I of Docket No. A–80–6.

The regulation will require no reports in addition to those required under the General Provisions of 40 CFR Part 60. The General Provisions contain notification requirements that enable the Agency to keep abreast of facilities subject to the standard and also contain requirements for conducting and reporting of initial performance tests. The resources needed by industry to maintain records and to prepare the reports through the first 5 years would be about 28 person-years. The resources required by EPA and State and local agencies to process the reports and maintain records through the first 5 years would be about 1.5 person-years. Analysis of these reporting requirements indicates that they are reasonable considering the savings in Agency time and resources required for effective enforcement.

The Paperwork Reduction Act of 1980 (Pub. L. 95–511) requires clearance from the Office of Management and Budget (OMB) of certain public reporting/recordkeeping requirements before this rulemaking can be promulgated as final. The reporting/recordkeeping requirements associated with this standard have been approved by OMB, and has been assigned OMB Control Number 2000–0473.

Regulatory Flexibility Analysis

This rulemaking was proposed before January 1, 1981, and therefore is not subject to the requirements of the Regulatory Flexibility Act. However, these requirements were reviewed, and it was determined that this rule would not have a significant economic impact on a substantial number of small entities.

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this rulemaking. The docket system is intended to allow members of the industries involved and the public to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket, except for certain interagency review materials, will serve as the record in case of judicial review [Section 307(d)(7)(A)].

Miscellaneous

The effective date of this regulation is October 27, 1982. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal December 24, 1980.

As prescribed by Section 111, promulgation of this standard was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of this promulgated standard was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All

aspects of the assessment were considered in the formulation of the standard to ensure that cost was carefully considered in determining BDT. The economic impact assessment is included in the BID for the proposed standard.

In addition to the economic impact analysis, the emissions reduction and annualized costs for typical facilities—expressed in dollars per ton of pollutant removed per year—were examined for several regulatory alternatives and results included in the BID for the proposed standard. Although such data are often used as a measure of the economic efficiency of pollution control systems, this concept of cost effectiveness was not directly applicable here because the alternatives considered represented different coating technologies rather than varying degrees of control within the same technology. A given coating technology may not be technically the most appropriate for a given segment of the industry, even though that technology may be more cost effective for the industry as a whole. Therefore, a plant operator must select a specific coating technology with an established cost and associated emissions and may not have the option of selecting a control system whose efficiency depends upon capital and operating costs alone.

As previously discussed, BDT for this industry has been determined to be the application of a coating containing 62 percent by volume coating solids at a 60-percent transfer efficiency (Alternative II). This decision was made primarily for technological rather than for economic reasons.

The emissions and annualized costs in the absence of an NSPS are nearly identical to those for the NSPS level of control in a nonattainment area. Compared to an uncontrolled plant in an attainment area, however, the NSPS level represents an emission reduction of 104 tons per year and an annual savings of about $682 per ton of emissions reduced for a prime coat operation and an emission reduction of 173 tons per year and an annual savings of approximately $758 per ton of emissions reduced for a topcoat operation. These savings result from reduced material costs. EDP (Alternative III) and powder coating (Alternative IV) are not required by the standard but may be selected in some instances. Compared to an uncontrolled plant, these result in annual savings of approximately $1,400 and $10,000 per ton of emissions reduced, respectively. These technologies, however, are not universally applicable.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because (1) the national annualized compliance costs, including capital charges resulting from the standard, total less than $100 million; (2) the standard does not cause a major increase in prices or production costs; and (3) the standard does not cause significant adverse effects on domestic competition, employment, investment, productivity, innovation, or competition in foreign markets. This regulation was submitted to OMB for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are included in Docket Number A–80–6. The docket is available for public inspection at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street SW., Washington, D.C. 20460.

Dated: October 20, 1982.

Anne M. Gorsuch,

Administrator.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc.

PART 60—[AMENDED]

40 CFR Part 60 is amended by adding a new Subpart SS as follows:

Subpart SS—Standards of Performance for Industrial Surface Coating: Large Appliances

Sec.

60.450 Applicability and designation of affected facility.
60.451 Definitions.
60.452 Standard for volatile organic compounds.
60.453 Performance test and compliance provisions
60.454 Monitoring of emissions and operations.
60.455 Reporting and recordkeeping requirements.
60.456 Test methods and procedures.

Authority: Sections 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a), and additional authority as noted below.

§ 60.450 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each surface coating operation in a large appliance surface coating line.

(b) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after December 24, 1980.

§ 60.451 Definitions.

(a) All terms used in this subpart not defined below are given the meaning in the Act or in Subpart A of this part.

"Applied coating solids" means the coating solids that adhere to the surface of the large appliance part being coated.

"Large appliance part" means any organic surface-coated metal lid, door, casing, panel, or other interior or exterior metal part or accessory that is assembled to form a large appliance product. Parts subject to in-use temperatures in excess of 250° F are not included in this definition.

"Large appliance product" means any organic surface-coated metal range, oven, microwave oven, refrigerator, freezer, washer, dryer, dishwasher, water heater, or trash compactor manufactured for household, commercial, or recreational use.

"Large appliance surface coating line" means that portion of a large appliance assembly plant engaged in the application and curing of organic surface coatings on large appliance parts or products.

"Coating application station" means that portion of the large appliance surface coating operation where a prime coat or a top coat is applied to large appliance parts or products (e.g., dip tank, spray booth, or flow coating unit).

"Curing oven" means a device that uses heat to dry or cure the coating(s) applied to large appliance parts or products.

"Electrodeposition" (EDP) means a method of coating application in which the large appliance part or product is submerged in a tank filled with coating material suspended in water and an electrical potential is used to enhance deposition of the material on the part or product.

"Flashoff area" means the portion of a surface coating line between the coating application station and the curing oven.

"Organic coating" means any coating used in a surface coating operation, including dilution solvents, from which VOC emissions occur during the application or the curing process. For the purpose of this regulation, powder

coatings are not included in this definition.

"Powder coating" means any surface coating that is applied as a dry powder and is fused into a continuous coating film through the use of heat.

"Spray booth" means the structure housing automatic or manual spray application equipment where a coating is applied to large appliance parts or products.

"Surface coating operation" means the system on a large appliance surface coating line used to apply and dry or cure an organic coating on the surface of large appliance parts or products. The surface coating operation may be a prime coat or a topcoat operation and includes the coating application station(s), flashoff area, and curing oven.

"Transfer efficiency" means the ratio of the amount of coating solids deposited onto the surface of a large appliance part or product to the total amount of coating solids used.

"VOC content" means the proportion of a coating that is volatile organic componds (VOC's), expressed as kilograms of VOC's per liter of coating solids.

"VOC emissions" means the mass of volatile organic compounds (VOC's), expressed as kilograms of VOC's per liter of applied coating solids, emitted from a surface coating operation.

(b) All symbols used in this subpart not defined below are given the meaning in the Act or Subpart A of this part.

C_a = the concentration of VOC's in a gas stream leaving a control device and entering the atmosphere (parts per million by volume, as carbon).

C_b = the concentration of VOC's in a gas stream entering a control device (parts per million by volume, as carbon).

C_f = the concentration of VOC's in a gas stream emitted directly to the atmosphere (parts per million by volume, as carbon).

D_c = density of coating (or input stream), as received (kilograms per liter).

D_d = density of a VOC-solvent added to coatings (kilograms per liter).

D_r = density of a VOC-solvent recovered by an emission control device (kilograms per liter).

E = the VOC destruction efficiency of a control device (fraction).

F = the proportion of total VOC's emitted by an affected facility that enters a control device (fraction).

G = the volume-weighted average mass of VOC's in coatings consumed in a calendar month per unit volume of applied coating solids (kilograms per liter).

L_c = the volume of coating consumed, as received (liters).

L_d = the volume of VOC-solvent added to coatings (liters).

L_r = the volume of VOC-solvent recovered by an emission control device (liters).

L_s = the volume of coating solids consumed (liters).

M_d = the mass of VOC-solvent added to coatings (kilograms).

M_o = the mass of VOC's in coatings consumed, as received (kilograms).

M_r = the mass of VOC's recovered by an emission control device (kilograms).

N = the volume-weighted average mass of VOC's emitted to the atmosphere per unit volume of applied coating solids (kilograms per liter).

Q_a = the volumetric flow rate of a gas stream leaving a control device and entering the atmosphere (dry standard cubic meters per hour).

Q_b = the volumetric flow rate of a gas stream entering a control device (dry standard cubic meters per hour).

Q_f = the volumetric flow rate of a gas stream emitted directly to the atmosphere (dry standard cubic meters per hour).

R = the overall VOC emission reduction achieved for an affected facility (fraction).

T = the transfer efficiency (fraction).

V_s = the proportion of solids in a coating (or input stream), as received (fraction by volume).

W_o = the proportion of VOC's in a coating (or input stream), as received (fraction by weight).

§ 60.452 Standard for volatile organic compounds.

On or after the date on which the performance test required by § 60.8 is completed, no owner or operator of an affected facility subject to the provisions of this supbart shall discharge or cause the discharge of VOC emissions that exceed 0.90 kilogram of VOC's per liter of applied coating solids from any surface coating operation on a large appliance surface coating line.

§ 60.453 Performance test and compliance provisions.

(a) Sections 60.8 (d) and (f) do not apply to the performance test procedures required by this subpart.

(b) The owner or operator of an affected facility shall conduct an initial performance text as required under § 60.8(a) and thereafter a performance test each calendar month for each affected facility according to the procedures in this paragraph.

(1) An owner or operator shall use the following procedures for any affected facility that does not use a capture system and control device to comply with the emissions limit specified under § 60.452. The owner or operator shall determine the composition of the coatings by formulation data supplied by the coating manufacturer or by analysis of each coating, as received, using Reference Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the coating manufacturer to determine the VOC content of coatings using Reference Method 24. The owner or operator shall determine the volume of coating and the mass of VOC-solvent used for thinning purposes from company records on a monthly basis. If a common coating distribution system serves more than one affected facility or serves both affected and existing facilities, the owner or operator shall estimate the volume of coatings used at each facility, by using the average dry weight of coating and the surface area coated by each affected and existing facility or by other procedures acceptable to the Administrator.

(i) Except as provided in subparagraph b(1)(iv) of this section, the weighted average of the total mass of VOC's consumed per unit volume of coating solids applied each calendar month will be determined as follows.

(A) Calculate the mass of VOC's consumed ($M_o + M_d$) during the calendar month for each affected facility by the following equation:

$$M_o + M_d = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj}, \quad (1)$$

($\Sigma L_{dj} D_{dj}$ will be 0 if no VOC-solvent is added to the coatings, as received)

where

n is the number of different coatings used during the calendar month, and

m is the number of different VOC-solvents added to coatings during the calendar month.

(B) Calculate the total volume of coatings solids used (L_s) in the calendar month for each affected facility by the following equation:

$$L_s = \sum_{i=1}^{n} L_{ci} V_{si}, \quad (2)$$

where

n is the number of different coatings used during the calendar month.

(C) Select the appropriate transfer efficiency from Table 1. If the owner or operator can demonstrate to the satisfaction of the Administrator that transfer efficiencies other than those shown are appropriate, the Administrator will approve their use on a case-by-case basis. Transfer efficiencies for application methods not listed shall be determined by the Administrator on a case-by-case basis. An owner or operator must submit sufficient data for the Administrator to judge the accuracy of the transfer efficiency claims.

TABLE 1.—TRANSFER EFFICIENCIES

Application method	Transfer efficiency (T_e)
Air-atomized spray	0.40
Airless spray	0.45
Manual electrostatic spray	0.60
Flow coat	0.85
Dip coat	0.85
Nonrotational automatic electrostatic spray	0.85
Rotating head automatic electrostatic spray	0.90
Electrodeposition	0.95

Where more than one application method is used within a single surface coating operation, the owner or operator shall determine the composition and volume of each coating applied by each method through a means acceptable to the Administrator and compute the weighted average transfer efficiency by the following equation:

$$T=\frac{\sum_{i=1}^{n}\sum_{k=1}^{m}L_{c_{ik}}V_{s_{ik}}T_{k}}{L_{a}}, \quad (3)$$

where
n is the number of coatings (or input streams) used, and
m is the number of application methods used.

(D) Calculate the volume-weighted average mass of VOC's consumed per unit volume of coating solids applied (G) during the calendar month for each affected facility by the following equation:

$$G=\frac{M_{o}+M_{d}}{L_{a}T}, \quad (4)$$

(ii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during the calendar month for each affected facility by the following equation:

$$N=G. \quad (5)$$

(iii) Where the volume-weighted average mass of VOC's discharged to the atmosphere per unit volume of coating solids applied (N) is equal to or less than 0.90 kilogram per liter, the affected facility is in compliance.

(iv) If each individual coating used by an affected facility has a VOC content, as received, which when divided by the lowest transfer efficiency at which the coating is applied, results in a value equal to or less than 0.90 kilogram per liter, the affected facility is in compliance, provided no VOC's are added to the coating during distribution or application.

(2) An owner or operator shall use the following procedures for any affected facility that uses a capture system and a control device that destroys VOC's (e.g., incinerator) to comply with the emission limit specified under § 60.452.

(i) Determine the overall reduction efficiency (R) for the capture system and control device. For the initial performance test the overall reduction efficiency (R) shall be determined as prescribed in A, B, and C below. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency (R) for the performance test, providing control device and capture system operating conditions have not changed. The procedure in A, B, and C, below, shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the initial performance test.

(A) Determine the fraction (F) of total VOC's emitted by an affected facility that enters the control device using the following equation:

$$F=\frac{\sum_{i=1}^{n}C_{a_i}Q_{a_i}}{\sum_{i=1}^{n}C_{a_i}Q_{a_i}+\sum_{k=1}^{p}C_{a_k}Q_{a_k}}, \quad (6)$$

Where
n is the number of gas streams entering the control device
p is the number of gas streams emitted directly to the atmosphere.

(B) Determine the destruction efficiency of the control device (E) using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation:

$$E=\frac{\sum_{i=1}^{n}Q_{b_i}C_{b_i}-\sum_{j=1}^{m}Q_{a_j}C_{a_j}}{\sum_{i=1}^{n}Q_{b_i}C_{b_i}}, \quad (7)$$

Where
n is the number of gas streams entering the control device, and
m is the number of gas streams leaving the control device and entering the atmosphere.

(C) Determine overall reduction efficiency (R) using the following equation:

$$R=EF. \quad (8)$$

(ii) Calculate the volume-weighted average of the total mass of VOC's per unit volume of applied coating solids (G) during each calendar month for each affected facility using equations (1), (2), (3) if applicable, and (4).

(iii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month by the following equation:

$$N=G(1-R). \quad (9)$$

(iv) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is equal to or less than 0.90 kilogram per liter of applied coating solids, the affected facility is in compliance.

(3) An owner or operator shall use the following procedure for any affected facility that uses a control device for VOC recovery (e.g., carbon adsorber) to comply with the applicable emission limit specified under § 60.452.

(i) Calculate the total mass of VOC's assumed (M_o+M_d) and the volume-weighted average of the total mass of VOC's per unit volume of applied coating solids (G) during each calendar month for each affected facility using equations (1), (2), (3) if applicable, and (4).

(ii) Calculate the total mass of VOC's recovered (M_r) during each calendar month using the following equation:

$$M_r=L_rD_r. \quad (10)$$

(iii) Calculate overall reduction efficiency of the control device (R) for each calendar month for each affected facility using the following equation:

$$R=\frac{M_r}{M_o+M_d} \quad (11)$$

(iv) Calculate the volume-weighted average mass of VOC's emitted to the atmosphere (N) for each calendar month for each affected facility using equation (9).

(v) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is equal to or less than 0.90 kilogram per liter of applied coating solids, the affected facility is in compliance. Each monthly calculation is considered a performance test.

§ 60.454 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses a capture system and an incinerator to comply with the emission limits specified under § 60.452 shall install, calibrate, maintain, and operate temperature measurement devices as prescribed below:

(1) Where thermal incineration is used, a temperature measurement device shall be installed in the firebox. Where catalytic incineration is used, a temperature measurement device shall be installed in the gas stream immediately before and after the catalyst bed.

(2) Each temperature measurement device shall be installed, calibrated, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of 0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5° C.

(3) Each temperature measurement device shall be equipped with a recording device so that a permanent continuous record is produced.

(Sec.114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.455 Reporting and recordkeeping requirements.

(a) The reporting requirements of §60.8(a) apply only to the initial performance test. Each owner or operator subject to the provisions of this subpart shall include the following data in the report of the initial performance test required under § 60.8(a):

(1) Except as provided in subparagraph (a)(2) of this section, the volume-weighted average mass of VOC's emitted to the atmosphere per volume of applied coating solids (N) for a period of 1 calendar month from each affected facility.

(2) For each affected facility where compliance is determined under the provisions of § 60.453(b)(1)(iv), a list of the coatings used during a period of 1 calendar month, the VOC content of each coating calculated from data determined using Reference Method 24 or supplied by the coating manufacturer, and the minimum transfer efficiency of any coating application equipment used during the month.

(3) For each affected facility where compliance is achieved through use of an incineration system, the following additional information will be reported:

(i) The proportion of total VOC's emitted that enters the control device (F).

(ii) The VOC reduction efficiency of the control device (E).

(iii) The average combustion temperature (or the average temperature upstream and downstream of the catalyst bed), and

(iv) A description of the method used to establish the amount of VOC's captured and sent to the incinerator.

(4) For each affected facility where compliance is achieved through use of a solvent recovery system, the following additional information will be reported:

(i) The volume of VOC-solvent recovered (L_r), and

(ii) The overall VOC emission reduction achieved (R).

(b) Following the initial performance test, the owner or operator of an affected facility shall identify and record:

(1) Each instance in which the volume-weighted average of the total mass of VOC's emitted to the atmosphere per volume of applied coating solids (N) is greater than the limit specified under § 60.452.

(2) Where compliance with § 60.452 is achieved through use of thermal incineration, each 3-hour period of coating operation during which the average temperature of the device was more than 28° C below the average temperature of the device during the most recent performance test at which destruction efficiency was determined as specified under § 60.453.

(3) Where compliance with § 60.452 is achieved through use of catalytic incineration, each 3-hour period of coating operation during which the average temperature recorded immediately before the catalyst bed is more than 28° C below the average temperature at the same location during the most recent performance test at which destruction efficiency was determined as specified under § 60.453. Additionally, all 3-hour periods of coating operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference across the catalyst bed during the most recent performance test at which destruction efficiency was determined as specified under § 60.453 will be recorded.

(c) Each owner or opreator subject to the provisions of this subpart shall maintain at the source, for a period of at least 2 years, records of all data and calculations used to determine VOC emissions from each affected facility. Where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain at the source daily records of the incinerator combustion chamber temperature. If catalytic incineration is used, the owner or operator shall maintain at the source daily records of the gas temperature, both upstream and downstream of the incinerator catalyst bed. Where compliance is achieved through the use of a solvent recovery system, the owner or operator shall maintain at the source daily records of the amount of solvent recovered by the system for each affected facility.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.456 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.452 as follows:

(1) Method 24 or formulation data supplied by the coating manufacturer to determine the VOC content of a coating. In the event of dispute, Reference Method 24 shall be the reference method. For determining compliance only, results of Method 24 analyses of waterborne coatings shall be adjusted as described in Subsection 4.4 of Method 24. Procedures to determine VOC emissions are provided in § 60.453.

(2) Method 25 for the measurement of the VOC concentration in the gas stream vent.

(3) Method 1 for sample and velocity traverses.

(4) Method 2 for volocity and volumetric flow rate.

(5) Method 3 for gas analysis.

(6) Method 4 for stack gas moisture.

(b) For Method 24, the coating sample must be a 1-liter sample taken into a 1-liter container at a point where the sample will be representative of the coating material.

(c) For Method 25, the sample time for each of three runs is to be at least 60 minutes and the minimum sample volume is to be at least 0.003 dscm except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) The Administrator will approve sampling of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that the testing of representative stacks would yield results comparable to those that would be obtained by testing all stacks.

(Sec. 114 of the Clean Air Act amended (42 U.S.C. 7414))

[FR Doc. 82-29516 Filed 10-26-82; 8:45 am]
BILLING CODE 6560-50-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2070-5(b)]

Standards of Performance for New Stationary Sources; Priority List; Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Withdrawal of proposed rule.

SUMMARY: This action withdraws the proposed amendment to the priority list that was published in the Federal Register (45 FR 85099) on December 24, 1980. The priority list is a list of major source categories for which EPA is required to promulgate new source performance standards (NSPS) and includes the category "Industrial Surface Coating: Large Applicances." The proposed amendment, which is being withdrawn, would have amended the priority list by aggregating all appliance surface coating operations (including small appliance coating operations) in one category.

After considering the comments received EPA has concluded that further study of applicable control technology is necessary before promulgating standards for this segement of the industry. The source category on the list will remain as "Industrial Surface Coating: Large Appliances."

DATE: This withdrawal is effective October 27, 1982.

ADDRESSES:

Background Information Documents. Background information on the emissions from the appliance surface coating industry may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone (919) 541-2777. Please refer to "Industrial Surface Coating: Appliances—Background Information for Proposed Standards," EPA-450/3-80-037a. Public comments on the proposed NSPS's for the appliance coating individual which bear on this withdrawal; EPA's responses to the Comments; and a summary of the changes made prior to promulgation are contained in the document, "Industrial Surface Coating: Large Appliances—Background Information for Promulgated Standards," EPA-450/3-80-037b, which is available from the same address.

Docket. A docket, number A-80-06, containing comments received during the public comment period for the proposed addition to the priority list and the proposed NSPS for appliance coating operations, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5624.

SUPPLEMENTARY INFORMATION: Under Section 111 of the Clean Air Act, EPA is required to develop a standard of performance for new stationary sources that the Administrator determines may contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Section 111(f) of the Act, as amended in 1977, requires that the Administrator promulgate a priority list of categories of major stationary sources for which standards of performance for new sources are to be promulgated.

In developing priorities, Section 111 specifies that the Administrator consider: (1) The quantity of emissions from each source category, (2) the extent to which each pollutant endangers public health or welfare, and (3) the mobility and competitive nature of each stationary source category.

The priority list, which identifies major source categories in order of priority for development, was proposed on August 31, 1978 and promulgated, after revisions, on August 21, 1979 (40 CFR 60.16, 44 FR 49222). Of the 59 source categories on the list, large appliance surface coating operations are listed as number 28.

On December 24, 1980 (45 FR 85099), EPA proposed to amend the priority list to aggregate all appliance surface coating operations into one source category. EPA studies of the appliance coating industry had indicated that the operations, processes, and emissions characteristic of the coating of certain comparatively small appliances were similar, and in many cases identical, to those associated with traditional, large appliance surface coating. Therefore, it appeared that there was no reason to distinguish among the emissions from appliance surface coating operations based solely on the size of the appliance being coated. Accordingly, the Administrator determined that emissions from appliance surface coating operations as a whole contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare.

Because of the similarities in coating materials and coating application techniques, some of these smaller appliances were included on the list of products to be covered by the proposed NSPS for "Industrial Surface Coating: Appliances," also published on December 24, 1980 (45 FR 85085). Comments received on that proposal have indicated certain important differences, of which EPA was not aware, between the manufacture and coating of smaller appliances and of the traditional, large household appliances.

After considering these comments, the Agency has concluded that further study of applicable control technology is necessary before promulgating standards for this segment of the industry. (See final promulgation of NSPS in this separate part of the Federal Register. In addition, the Administrator has concluded from these comments that further examination of such factors as the projected growth and applicable emission limits for other segments of the appliance coating industry are necessary before concluding that these other appliance coating operations contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Therefore, the Agency is withdrawing the proposed amendment to aggregate all appliance surface coating operations into one source category on the priority list.

Dated: October 20, 1982.

Anne M. Gorsuch,

Administrator.

[FR Doc. 82-29346 Filed 10-26-82; 8:45 am]

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federal register

Friday
October 29, 1982

Part X

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Surface Coating of Metal Furniture

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2053-7]

Standards of Performance for New Stationary Sources; Surface Coating of Metal Furniture

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for surface coating of metal furniture were proposed in the **Federal Register** on November 28, 1980 (45 FR 79390). This action promulgates standards of performance for surface coating of metal furniture. These standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination that metal furniture surface coating facilities cause, or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed metal furniture surface coating facilities to control emissions to the level achievable through use of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: October 29, 1982.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard (NSPS) is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESS: *Background Information Document.* The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Surface Coating of Metal Furniture—Background Information for Promulgated Standards" (EPA-450/3-80-007b). The BID contains (1) a summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final environmental impact statement which summarizes the impacts of the standards.

Docket. A docket, number A-79-47, containing information considered by EPA in development of the promulgated standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5624.

SUPPLEMENTARY INFORMATION: OMB control number: (2000-0649).

The Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standards apply to new, modified, or reconstructed metal furniture surface coating operations for which construction was commenced after November 28, 1980. Existing facilities are not subject to the regulation unless modified or reconstructed as defined in 40 CFR 60.14 or 60.15. The promulgated standards will limit emissions of volatile organic compounds (VOC) from each metal furniture surface coating operation consisting of application station(s), flash-off area, and curing oven. A metal furniture surface coating operation may be either a prime coat or topcoat operation within a metal furniture plant where metal furniture parts or products are being coated with organic coatings. Powder coatings, however, are excluded from the definition of organic coatings. Emissions of VOC from each affected facility will be limited to a monthly average of 0.90 kilogram of VOC per liter of coating solids applied. The Agency has identified as the best demonstrated technology the use of either high solids coatings, waterborne coatings, or powder coatings (with the appropriate application equipment). The emission limit is based on the use of 62 percent by volume solids coating applied at 60 percent transfer efficiency and an assumed solvent density of 0.88 kilogram per liter. Compliance could also be achieved with add-on control devices, a combination of add-on control devices and a low organic solvent coating, or any combination of coating and transfer efficiency that limits emissions to 0.90 kilogram of VOC per liter of coating solids applied.

Following the initial 1 month performance test, the owner or operator must calculate and record the VOC emissions from each affected facility for each calendar month. Each monthly calculation is considered a performance test. The information necessary to perform the monthly calculation can be obtained from company records and data supplied by the manufacturer of the coating or by an analysis of the coating by Reference Method 24. Equations and transfer efficiencies for calculating the emissions for each affected facility are provided in the standards. Reference Methods 1, 2, 3, 4, and 25 will be used to determine the percentage reduction of VOC emissions achieved through the use of a capture system and control device.

Recordkeeping requirements include those data necessary to substantiate the monthly calculations of emissions. These data must be retained at the source for a period of 2 years. The regulation contains no reporting requirements in addition to those required by the General Provisions to 40 CFR Part 60 relative to the initial performance test.

Summary of Environmental, Energy, And Economic Impacts

The metal furniture industry is composed of approximately 1,400 plants, many of which have multiple surface coating operations. The EPA estimates that the promulgated standards will affect 800 new and 1,200 modified or reconstructed sources within the first 5 years after the standard is effective. The typical "uncontrolled" metal furniture manufacturer applies paint that contains about 35 percent by volume solids. In contrast, a control techniques guideline (CTG) document, entitled "Control of Volatile Organic Emissions from Existing Stationary Sources, Volume III: Surface Coating of Metal Furniture" (EPA-450/2-77-032) which defines reasonably available control technology (RACT), recommends that a 60 percent by volume solids coating be adopted by States into their State implementation plans (SIP's). The same metal furniture manufacturer applying a CTG complying

coating would emit about 60 percent less VOC compared to the uncontrolled coating. It is estimated that this CTG recommendation could reduce emissions of VOC from about 49.8 megagrams per year to about 19.4 megagrams per year. The promulgated standards would reduce VOC emissions to about 18.0 megagrams per year for the typical plant (assuming two affected facilities per plant) which is an additional 7 percent emission reduction below the CTG recommendation. This represents an industrywide annual reduction in the fifth year of 1,400 megagrams per year.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, an evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. The costs are provided in an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact controls on an industry.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government and the public affected by that industry's emission.

The impact of the promulgated standards on water pullution would depend on the control option selected. For example, water use in spray booths would be unnecessary when powder coatings are used. Therefore, there would be a decrease in wastewater discharged when the promulgated standards are met by employing powder coatings. Wastewater discharges could be expected not to increase for plants which utilize higher solids and waterborne coatings. The quality of wastewater discharged is expected to remain the same for plants that apply higher solids coatings when compared to that from plants that employ solvent-borne coatings. However, the quality of wastewater discharged from plants applying waterborne coatings could be reduced because these coatings contain water-miscible solvents. Finally, where incineration is used, the water pollution impact would depend on the type of coating used.

The impact on solid waste generation also depends on the control option selected. Powder coatings are generally recycled so that there is little waste. Higher solids and waterborne coatings produce about the same amount of solid waste as solvent-borne coatings. The use of an incinerator on a bake oven would have no effect on the amount of solid waste generated from the types of coatings applied.

For a typical metal furniture manufacturer complying with the recommended CTG, energy requirements would vary depending upon which control option is employed to meet the promulgated standards. Energy consumption would decrease by about 20 percent (15 gigajoules) if powder coatings were used. Energy consumption would increase, however, with the use of waterborne coatings or with incineration plus a CTG coating by about 3 percent (2.3 gigajoules) and 7 percent (5.2 gigajoules), respectively.

The economic impact summary presented in this section is based on the total anticipated costs of constructing and operating a new coating facility. Many of the control options considered involve a redesigning of the coating facility rather than simply adding equipment to an existing design. Usually powder coatings and waterborne coatings, for example, could not be applied in a facility equipped to use a solvent-based coating. For this reason, the capital and annualized costs represent a comparison of the total cost of each type of controlled facility rather than an incremental difference in the cost of each type of facility.

For a new typical spray coating plant with two coating lines, the initial capital and annualized costs do not vary significantly regardless of which control option would be employed to comply with the promulgated standards. Capital costs for each of the different control options are expected to range from about $960,000 (higher solids coatings) to about $1,200,000 (waterborne coatings). The capital cost for a typical CTG coating facility or a typical uncontrolled coating facility would be about $960,000. The annualized costs for the different control options would range from about $600,000 to $700,000. These annualized costs would be comparable to the annualized costs for a typical CTG coating facility ($620,000) and a typical uncontrolled facility ($630,000).

Total annualized costs (savings) vary depending upon which control option would be employed to comply with the promulgated standards for all new, modified, and reconstructed spray coating plants (e.g., large, medium, and small sizes). For these facilities the fifth year industrywide annualized costs, if all affected facilities used a combination of incineration and waterborne coatings, would be about $17 million. An industrywide savings of $18 million would result in the fifth year if high solids coatings were used by all affected facilities. The total industrywide annualized costs for powder coatings could vary from a savings of $2 million to a cost of $126 million depending upon achieved coating thickness and other factors. In the proposal preamble an industrywide annualized fifth-year cost of $11 million was projected. This projection was based on the assumption that higher solids coatings, powder coatings, and a combination of incineration and waterborne coatings would each be used by one-third of the affected spray coating facilities. It is estimated at this time, however, that 80 percent of the affected spray coating facilities will use higher solids coatings, 10 percent will use powder coatings, and 10 percent will use a combination of incineration and waterborne coatings. Based on this distribution, there is a potential for industrywide annualized savings of $13.9 million in the fifth year after the standard is in effect. These costs (savings) do not include lost opportunity costs (i.e., the profit or return on investment which could be derived by investing in other than air pollution control equipment).

The economic impacts of the promulgated standards were evaluated based upon reduced profitability, inflationary impact, and expected price increases. The highest profit impairment is expected for small metal furniture manufacturers (4,000 liters of coatings consumed annually) regardless of control option. The maximum impact could result in about a 1.3 percent increase in the wholesale price of a metal furniture product from the small manufacturer.

The environmental, energy, and economic impacts are discussed in greater detail in the background information document for the proposed standards, "Surface Coating of Metal Furniture—Background Information for Proposed Standards" (EPA–450/3–80–007a).

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register March 17, 1978, and February 11, 1980) of the meetings of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) to discuss the surface coating of metal furniture standard recommended for proposal. The first meeting was held on April 5–6, 1978, and an updated NAPCTAC presentation was given on February 27, 1980. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the Federal Register on November 28, 1980 (45 FR 79390). The preamble to the proposed standards discussed the availability of the background information document (BID), "Surface Coating of Metal Furniture—Background Information for Proposed Standards" (EPA–450/3–80–007a), which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on January 9, 1981, at Research Triangle Park, North Carolina. The hearing was open to the public and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from January 9, 1981 to March 10, 1981.

Ten comment letters were received, and four interested parties testified at the public hearing concerning issues relative to the proposed standards of performance for the surface coating of metal furniture. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from industry, trade associations, and one State air pollution control agency. A detailed discussion of these comments and responses can be found in the BID for the promulgated standards, which is referred to in the **ADDRESSES** section of this preamble. The summary of comments and responses in the BID serve as the basis for the revisions which have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The comments have been divided into the following areas: General, Emission Control Technology, Modification and Reconstruction, Economic Impact, Environmental Impact, Energy Impact, and Reporting and Recordkeeping.

General

Several commenters requested a change in the definition of the affected facility to include all finishing systems within a manufacturing plant or the finishing system necessary to provide a finished product. This would allow a plant to average its topcoat emissions with the much lower emissions from an electrocoat system. One commenter requested that the NSPS allow the option of a plantwide emission reduction plan, particularly as it relates to application of the bubble concept for new and/or modified sources at a given plant.

The choice of the affected facility for this standard (each surface coating operation which includes the application station(s), flash-off area, and bake oven) is based on EPA's interpretation of Section 111 of the Clean Air Act and judicial construction of its meeting. In choosing the affected facility, EPA must decide which pieces or groups of equipment are the appropriate units for separate emission standards in the particular industrial context involved. EPA must do this by examining the situation in light of the terms and purpose of Section 111. One major consideration in this examination is that the use of a narrower definition results in bringing replacement equipment under NSPS sooner; if, for example, an entire plant were designated as the affected facility, no part of the plant would be covered by the standard unless the plant as a whole is "modified." If, on the other hand, each piece of equipment is designated as the affected facility, then as each piece is replaced, the replacement piece will be a new source subject to the standard. Since the purpose of Section 111 is to minimize emissions by the application of the best demonstrated control technology (considering cost, other health and environmental effects, and energy requirements) at all new and modified sources, there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources within plants will be brought under the coverage of the standards as they are installed. This presumption can be overcome, however, if the Agency concludes that the relevant statutory factors (technical feasibility, cost, energy, and other environmental impacts) point to a broader definition. Since it is technologically feasible to control each surface coating operation and such control would not be exorbitantly costly (as shown in the economic analysis section of the BID accompanying the proposed standards), selecting this narrowest definition of affected facility is most consistent with the purposes of Section 111.

Two other possible definitions of the affected facility for this standard are: all prime coat (or topcoat) operations in a product line and all prime coat (or topcoat) operations within an assembly plant. The product line definition would have reduced the number of affected facilities and would have permitted tradeoffs between different coatings and application technologies. Likewise, defining all prime coating (or topcoating) operations within a plant as the affected facility would have reduced the number of affected facilities and consequently the associated recordkeeping and compliance calculations. However, such a definition would not necessarily result in either the use of the best technology or the minimizing of emissions from new sources.

For these reasons, the Agency has chosen each surface coating operation as the affected facility.

One commenter stated that the metal furniture industry should not be considered as a "significant source of VOC emissions." He pointed out that EPA listed the industry as a minor source of VOC's according to the impact it would have on public health and also that EPA estimates VOC emissions from the industry at 5 percent of the Nation's VOC emissions.

Standards of performance are promulgated under Section 111 of the Clean Air Act. Section 111(b)(1)(A) requires that the Administrator establish standards of performance for categories of new, modified, or reconstructed stationary sources which in her judgment cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. One important purpose of standards of performance is to prevent new air pollution problems from developing by requiring the application of the best technological system of continuous emission reduction which the Administrator determines to be adequately demonstrated. The 1977 Amendments to the Clean Air Act added the words, "in the Administrator's judgment," and the words, "may reasonably be

anticipated," to the statutory test. The legislative history for these changes stresses two points: (1) The Act is preventive, and regulatory action should be taken to prevent harm before it occurs; and (2) the Administrator should consider the role of each single class of sources in contributing to the comulative impact of VOC emissions from all sources.

The 1977 Amendments to the Clean Air Act also required that the Administrator promulgate a priority list of source categories for which standards of performance are to be promulgated. A list for new source performance standards was promulgated at 44 FR 49222 (August 21, 1979). Priority ranking was based on consideration of the source's quantity of emission, the extent to which each pollutant endangers public health and welfare, and the mobility and competitive nature of the source category. The statutory test for listing a category of sources was that it "causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

As stated in the preamble for the proposed standards, the surface coating of metal furniture is listed as a minor source category on this listing. This classification as a minor source is due primarily to the fact that individual metal furniture surface coating plants typically emit less than 100 tons of VOC per year. However, the priority list states that "the metal furniture coating industry is also a significant source of VOC emissions, and there are over 300 existing facilities with the potential to emit more than 100 tons per year."

There are approximately 1,400 metal furniture manufacturing establishments in the United States which paint their products. These metal furniture manufactures are located throughout the country and are generally situated in highly populated urban areas. In fact, 70 percent of the industry is concentrated in nine highly populated States.

The metal furniture industry emits about 95.5 gigagrams (1975 data) of VOC per year. The emissions of VOC result from usage of solvent-based coatings by the industry. These coatings contain organic solvent mixtures of aromatics, saturated and unsaturated aliphatics, alcohols, ketones, esters, and ethers. The emissions of these organic solvents contribute to ozone formation in urban atmospheres. EPA has established a national ambient air quality standard (NAAQS) for ozone of 0.12 microgram per cubic meter which is currently exceeded in those States where metal furniture manufacturing establishments are concentrated. Information concerning health and welfare effects associated with ozone can be found in "Air Quality Criteria for Ozone and Other Photochemical Oxidants" (EPA-600/8-78-004).

The Administrator is called upon in the Clean Air Act to evaluate an industry's contribution to air pollution and make a determination as to the significance of the subject industry's emission contribution. In the case of the metal furniture surface coating industry, the Administrator has determined that even though the total amount of emissions from a single plant (like that from many sources which contribute to the inventory of VOC emissions) is by itself a small portion of the Nation's total VOC emissions, this industry would contribute significantly to the Nation's total VOC emissions.

In addition, the metal furniture industry is projected to have an annual growth rate of 4 percent through 1985 and will include about 2,000 new, modified, or reconstructed affected facilities by 1985. Based on this growth, the industry will contribute increasing amounts of VOC to urban atmospheres.

Therefore, industrial surface coating of metal furniture was listed as a "significant contributor". This selection was based upon the number of affected facilities, coating method, the yearly VOC emission rate, the growth rate of the industry, and the location of this industry in or near highly populated urban areas.

One commenter requested that the effective date of the standard be the promulgation date rather than the proposal date.

Section 111(a)(2) of the Clean Air Act states, "The term 'new source' means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." Therefore, the statute requires that the applicability date for a new or revised standard be the date of the proposal.

One commenter stated that coatings manufacturers and users have the right to demand the same treatment as other citizens who continue to use pounds and gallons instead of metric equivalents.

It is EPA's policy to use metric units, not English units, in regulations and technical documents. This policy is in conformance with Section 3 of Public Law 94-168, the Metric Conversion Act of 1975, which states that the policy of the United States shall be to coordinate and plan the increasing use of the metric system. Therefore, EPA is now in the process of incorporating the International System of Units (SI) into all of its regulations. EPA is currently using as the basic reference a publication entitled "Standard for Metric Practice" (E 380-76) published by the American Society for Testing and Materials (ASTM). This publication explains the SI units and symbols, their application, and rules for conversion and rounding. It may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103. This document is useful in explaining the abbreviations of units of measurement cited in EPA regulations.

Emission Control Technology

Two commenters objected to statements in the preamble that 68 percent by volume solids coatings are demonstrated in this industry and are readily available for use. They contend that such coatings are not currently being applied by hand-held electrostatic spray equipment and are not available for use by the industry. According to one commenter, stricter regulations on the industry are not justified by the state of the art of the control technology, the situation with the economy, and the high cost of borrowing money. Another commenter stated that EPA is forcing technological changes too rapidly upon an industry at a time when efforts should be going into making coatings more cost effective and energy efficient. Another commenter stated that the high viscosity of coatings with greater than 60 percent by volume solids creates problems in accomplishing rapid color changes and that atomization problems limit the types of spray equipment which can be used. According to one commenter, there is not enough technical basis given for setting the standards at the 68 percent volume solids level. He stated that the proposed control level was apparently derived by merely reducing the CTG emission limit by 30 percent. Another commenter stated that he viewed the proposed emission limit as "an arbitrary level of suspect origin."

The proposed standard was based on an analysis of four alternative levels of controls as described in the preamble. Information obtained during the analysis led to the determination that 68 percent by volume solids coatings were being produced by some coating manufacturers and had been successfully applied in production tests. Therefore, the use of a 68 percent by volume solids coating was selected as the basis for the proposed standards. As a result of the comments concerning the availability and applicability of coatings

with a 68 percent volume solids content, EPA conducted a survey of several coatings manufacturers and users. The results of this survey (see Docket item IV-B-8) indicate that although much laboratory work and some production testing have been done with 68 percent volume solids coatings, there are some problems which must be overcome before these coatings can be considered as the best demonstrated technology. The single most difficult problem appears to be the increase in viscosity of the coating as the solids content approaches 68 percent by volume. Increased viscosity requires more energy for manufacturing, and increases agitation requirements during storing, pumping, and atomization of the coatings. Improper atomization of the coatings by the spray equipment also causes problems with the finish obtained on the metal surface.

Survey results showed that advances are currently being made in the field of higher solids coatings. Several coating manufacturers claim to have coatings, available in a wide range of colors, which can be applied by existing spray equipment and have percent solids contents in the low 60's. Some manufacturers explained that since the States are generally adopting the CTG document recommended emission level based on 60 percent by volume solids, all their efforts have gone toward achieving this level. At this volume solids level, the problems with viscosity can be overcome by increased use of in-line heating and slightly larger recirculation pumps.

Most spray equipment manufacturers contacted during the survey indicated that atomization and application of coatings with a percent solids content above 60 has been demonstrated in production tests. Some of the manufacturers recommended the use of in-line heaters in order to maintain a constant material temperature and indicated that these heaters would not be difficult to install. Several of the equipment manufacturers have stated that much of the problem encountered when applying higher solids coatings is directly related to the operator rather than the equipment. Accordingly to these contacts, the difficulties in obtaining proper film thickness is a result of solids being delivered to the nozzle at a greater rate than operators are accustomed to. This creates a situation in which the operator is using his normal application pattern and is applying more solids to the target than is necessary, resulting in excessive film thickness. The equipment suppliers indicate that this problem can be overcome by proper operator training and more careful control of material flow rates.

Several representatives of the metal furniture industry were contacted during the survey. Most of those contacted have experimented with higher solids coatings in order to achieve the emission limits required by State implementation plans (SIP's). Results of these trials have been mixed, with some plants experiencing viscosity, atomization, and excessive film thickness problems when attempting to apply higher solids coatings with existing coating lines. However, through the use of techniques such as in-line heating, larger diameter piping, reduced material flow rates, and improved operator training, many companies have successfully applied coatings which will comply with the SIP's. Due to the rapid increase in the viscosity of coatings as the solids content increases, these techniques are much less efficient and less cost effective at 68 percent by volume solids level than at 62 percent by volume solids. Three plants are currently using coatings with a least 62 percent by volume solids contents. These three plants are considered typical of the industry; two are manufacturers of office furniture and the other manufactures shelving and store fixtures. This represents a wide range of coating uses and specifications since the appearance of office furniture is very critical and the durability of shelving is important. In-line heating is used to aid in viscosity control at one of the plants, and a wide variety of hand-held and automatic spray equipment is used at these plants. A wide range of colors are applied at these plants and the surface on the product is considered acceptable.

One commenter pointed out that most coatings suppliers are currently offering higher volume solids systems that are basically versions of the old lower volume solids systems. The main limitation of this approach is viscosity, i.e., as the volume solids increases, the viscosity increases. The short-term solution which coating manufacturers are using to solve viscosity problems can cause problems with the quality of the finish on the product. Molecular weight reduction of solvents and coatings also decreases covering.

One of the commenters stated that hand-held electrostatic spray guns are widely used in the metal furniture industry due to the complexity of the metal furniture configuration and the mix of parts. There is some touch-up required for hard-to-reach areas where this type of equipment is necessary. However, hand-held electrostatic spray guns are limited in their ability to atomize 68 percent by volume solids coatings because of their greater viscosity. Therefore, there would be a problem achieving the desired quality of finish.

Another commenter claimed that due to finish specifications for certain types of metal furniture (for example, matching the color and texture of products that were produced during different time periods), automatic electrostatic spray equipment must be used. However, he stated that he has not been able to spray coatings with higher than 60 percent volume solids with this equipment due to the viscosity of these coatings.

One commenter stated that equipment is not available which will spray high solids coatings with their increased viscosity and still maintain the proper film thickness and texture without excessive overspray. Another stated that automatic electrostatic equipment is required to produce a consistent film thickness and that a great deal of manual touch-up is required when the solids content of the coatings is increased.

When the volume solids content of a coating increases, the viscosity also increases. It has been confirmed by several coating manufacturers and users that the higher solids coatings which comply with the proposed standard cause significant problems due to their higher viscosity.

However, the standard is being revised to a level which can be met by available coatings which are acceptable in terms of viscosity and coverage capacity. The emission limit is now based on the use of a coating with 62 percent volume solids content. Hand-held electrostatic spray guns capable of atomizing and applying 62 percent by volume solids coatings are currently being marketed by several well-known manufacturers of spray equipment. Five of the six spray equipment manufacturers recently contacted stated they have equipment available which can satisfactorily apply 62 percent volume solids coatings. Most manufacturers have indicated that automatic electrostatic spray equipment is the most proven method of applying high solids coatings. Three manufacturers contacted recently indicated that they are successfully applying coatings with greater than 60 percent by volume solids contents. The film thickness and touch-up requirement problems are solved, according to the equipment manufacturers, by proper training of operators and more exact process controls. Based on this

information, it is EPA's judgment that hand-held and automatic electrostatic spray equipment can satisfactorily apply 62 percent volume solids coatings.

Some coatings with 68 percent by volume solids are available, but their use is limited to certain products and application with specific equipment which may not be feasible in certain situations. Therefore, EPA is revising the emission limit from 0.7 to 0.9 kilogram of VOC per liter of applied solids. This level is based on the use of a coating with 62 percent by volume solids, a solvent density of 0.88 kilogram per liter, and a transfer efficiency of 60 percent.

According to one commenter, the basic problem with alternative coating systems such as waterbased coatings, powder, electrodeposition, dip and flow coatings (which EPA interprets to mean those systems which would meet the standard) is the difficulty in obtaining color/texture matching with products painted by conventional sprays. Another commenter stated that the alternative coating systems are not applicable for a wide range of uses within the industry, thus limiting the choices of control options available to some segments of the industry.

The Agency has identified as the best demonstrated technology the use of either high solids coatings, waterborne coatings, or powder coatings (with appropriate application equipment). The standard is achievable through the use of these methods; and as a result, the industry has a choice among several methods capable of meeting the standard. For example, a coater desiring a thick film with high durability might choose powder coating for a product. Two coats of a high solids coating, however, might also accomplish the desired results. Powder or EDP might be a coater's choice if only one or two colors are required. Furthermore, even though EPA's economic analysis has shown that waterbased coatings are likely to be the most expensive option for controlling VOC emissions, some metal furniture manufacturers have chosen to use them. Clearly, in an industry which produces such a wide variety of products as the metal furniture industry, there are always a few situations where, due to product specifications, the number of alternative control methods will be limited. Electrodeposition cannot be used on non-conductive materials, for example, and waterbased coatings require extra precaution against corrosion. Products requiring a metallic finish could not be coated with powder coatings. Nevertheless, there is always at least one coating method that can meet the standards and the color/texture requirements of the industry. The Agency has determined, based on the analysis of the most costly method of control, that when only one method applies, the cost of using that method is reasonable.

Several commenters made statements concerning the use of the table of assigned transfer efficiencies in the regulation. One commenter suggested that a production line testing program be used to determine the proper efficiencies and that EPA clarify whether the table values were intended for equipment manufacturers or users. Another commenter stated that the assigned values seemed unrealistic to be used as universal standards. He also stated that if transfer efficiencies are to be assigned, however, then all known application methods should be included in order to avoid the time-consuming process of obtaining approval to use alternative equipment. In his comment, he noted that the continuous coater method and the liquid seal process were not mentioned.

One commenter presented a very detailed alternative to the use of the existing table of transfer efficiencies. He stated that the generic classifications of equipment now in the regulation is very poorly defined and explained that actual transfer efficiency is dependent on many factors such as equipment configuration, operating conditions, the part being coated, the coating being applied, and the operator. He recommended that the variables in design and operation of equipment be considered by defining such parameters as voltage, atomizing pressure, flow rates, etc., of each type of spray equipment. He also suggested that a standardized test method be adopted to determine transfer efficiency of equipment. Equipment could then be "certified" by the manufacturers, a list of equipment ratings and operating conditions could be supplied to EPA for publication.

EPA believes that to reflect the best demonstrated technology for the metal furniture coating industry, emission limits for new sources must incorporate the use of both high solids coatings and relatively efficient application equipment, but must not at the same time deny industry flexibility to use different types of application equipment and different coatings. For this reason, the Agency has included the key transfer efficiency concept in these standards.

The commenters' claim that all the listed parameters affect transfer efficiency is correct. However, a universally acceptable test method for determining precise transfer efficiency under each conceivable set of variables has not yet been developed. This means that the Agency must either delete this crucial component of BDT or instead include in the standards assigned transfer efficiency values that correlate at least generally to the efficiencies of the application equipment used in the industry. EPA has chosen the latter course. The Agency has included values that are correlated to each piece of equipment and are sufficiently high to ensure that, regardless of coating properties and other relevant variables, each facility will be credited with at least the efficiency its equipment attains with the particular coatings it applies. These transfer efficiencies listed are based on data provided by spray equipment manufacturers and results of tests conducted during standard development. EPA contacted and visited several equipment and coatings manufacturers during the standard development process.

Moreover, the standards provide that if the operator can demonstrate to the satisfaction of the Administrator that other transfer efficiencies are appropriate (e.g., due to variables such as those cited in the comment), the Administrator will approve their use on a case-by-case basis. This provision ensures that a facility using equipment that achieves an efficiency greater than that assigned by the standard is fully credited for the efficiency achieved. The certification of spray equipment by manufacturers can be undertaken by the industries and trade associations without EPA involvement.

The preponderance of metal furniture coating application techniques is addressed in the table. In addition, the regulation contains provisions whereby alternative coating equipment may be approved. Transfer efficiency values for coating methods which are not specifically addressed in the table can be determined in a manner similar to the way the table was developed. Data can be obtained from the manufacturer of the equipment; testing procedures can be submitted; and, based on an analysis of the data, EPA will determine the efficiency to be used in the emission calculations. The Agency does not believe this process of obtaining the Administrator's approval to use alternative equipment would be unreasonably time consuming. Also, this approval need only be obtained once for any one application technique. The values in the transfer efficiency table will be reviewed in the future, and

techniques in general use at that time may be added to the table.

One commenter suggested that key operating parameters of spray equipment be monitored on a regular basis (monthly) to be sure they are within design specifications. He recommended this be done at the same time that monthly determination of VOC emission compliance occurs.

While EPA considers that the proper operation and maintenance of spray equipment should be a routine procedure, the variations in operating parameters are understood to be great. Subpart A of the General Provisions of 40 CFR Part 60, § 60.11(d) states that: "At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source." EPA believes that this general requirement, coupled with economic incentives such as reduced coating use, is sufficient to ensure that coatings users routinely check key operating parameters and maintain application equipment in good condition.

One commenter submitted information concerning the potential for cost effectiveness and performance of regenerative thermal oxidation systems. A system designed by the commenter is claimed to be capable of providing primary heat exchange efficiencies of 85 percent, 90 percent, and 95 percent in the thermal oxidation process. The high thermal energy recovery of this system allows operation in a self-sustaining mode on hydrocarbon concentrations from 3 to 5 percent of the lower explosive limit (LEL). Little or no additional fuel is required. This system virtually eliminates the following problem areas generally associated with incineration systems: (1) Fouling of heat transfer surfaces, (2) corrosion, (3) catalyst poisoning, (4) secondary emissions, and (5) high operating costs with low LEL gas streams. The commenter requested clarification of the potential of regenerative thermal oxidation systems in the documentation for the promulgated standard.

The analysis of incineration found in Chapter 3 of the proposal BID (EPA–450/3–80–007a) reveals that this option has a significantly greater capital investment and an increase in energy consumption, over other control options. Although the annual operating costs and energy use of a regenerative thermal oxidation system may be lower, the initial capital investment is large compared to that for low solvent coatings technology. The reduction in total organic solvent emissions realized by controlling the topcoat oven is small because only 20 to 30 percent of these emissions are concentrated in the oven. The remaining 70 to 80 percent of the emission are from fugitives from the application and flashoff areas. The small percentage of emissions available for reduction by incineration makes any incinerator difficult to justify on a cost basis when compared to low solvent coatings. Therefore, the Administrator does not believe that further clarification of the potential of regenerative thermal oxidation systems is necessary.

Modification and Reconstruction

Several commenters expressed concern that expenditures made to comply with a State implementation plan (SIP) could bring the facility under the NSPS as a reconstruction. They requested that this situation be avoided by exempting SIP-related expenditures from the reconstruction provisions included under the General Provisions of 40 CFR Part 60.

It is possible that when an existing facility is modified to meet a State requirement the capital costs incurred could be large enough to trigger the reconstruction provisions of the Federal regulations, thereby forcing compliance with the more restrictive Federal requirement. This was a valid issue at the time the standard was proposed with an emission limit that was considerably more restrictive than most State regulations. Since proposal, however, the recommended standard has been revised so that it is now based on the use of a coating only two percent higher in volume solids content than the coating recommended in the CTG document. Because the technologies required to comply with the two emission limits are similar and no additional equipment would be required to apply an NSPS complying coating versus a CTG complying coating, the commenters' situation is no longer considered to be an issue.

Economic Impact

One commenter stated that continued development of inflexible standards will impact the growth of the industry and result in loss of job opportunities. The commenter continued by saying that the cost to comply with the proposed standards will be much higher than projected. These increased costs are due to higher construction, operating, and energy costs. A comparison of cost and energy requirements for a plant built in 1977 versus a plant built in 1980 was submitted by the commenter.

It is definitely true that costs of construction, raw materials, labor, and energy have increased significantly since the economic analysis portion of the proposal BID was completed. Many of these costs, however, will not be any greater for a complying high solids coating system than for a conventional solvent coating system. If line heating, larger diameter recirculation lines, or more powerful agitation equipment is specified, there would be an increase in costs. However, these costs are considered to be reasonable. A recent Society of Manufacturing Engineers (SME) technical paper (FC81–237) reported that both operating and energy costs can actually be reduced by using high solids coatings rather than conventional solvent based coatings. The BID also indicates that a potential for savings in annualized costs exists with the use of higher solids coatings. This savings results from a decrease in the energy required to dry the coatings and lower labor and maintenance costs. Materials costs are also reduced because with higher solids coatings, even though the price per gallon may be higher, fewer gallons of coating are needed.

One commenter stated that the types of application equipment necessary to apply high solids coatings in order to meet the standards is exceedingly costly to the industry. Another commenter claimed that the electrostatic equipment is much more expensive than conventional spray equipment now being used.

The economic impacts discussed in the BID are based on the use of electrostatic equipment to apply higher solids coatings. Although electrostatic spray equipment is more expensive than conventional equipment, EPA believes its advantages outweigh the costs. The projected payback time for an average size plant purchasing electrostatic equipment in lieu of conventional equipment is less than one year. Most of the newer plants contacted during development of the standard were using electrostatic equipment (automatic and hand-held) because of the improved efficiency. Since the standard applies only to new sources and sources undergoing modification of reconstruction, it is anticipated that many affected facilities would use

electrostatic equipment even in the absence of the standard.

Energy Impact

A comment was received which stated that installation of incinerators on all spray booth stacks and oven vents to obtain compliance with the standards would be an expensive waste of energy due to the fuel which would be required to sustain combustion of the exhausted solvents.

Even though incineration is expected to have limited use in this industry as a means of controlling emissions, EPA did perform an analysis of the impacts of this alternative. The analysis of incineration as a means of emissions control indicated a substantial impact on energy consumption relative to other control technologies. This was the primary reason that incineration was not considered to be the best demonstrated control technology even though it is a control technology available at reasonable cost. EPA recognizes, however, that incineration of oven vents used in conjunction with coatings having a volume solids content less than 62 percent could be an alternative to using a 62 percent by volume solids coating system. Manufacturers using systems with partial incineration would have more flexibility in their selection of coatings and coating manufacturers and, by returning the available heat from the incinerator back to the process, would not experience a drastic increase in energy costs.

Reporting and Recordkeeping

Several commenters stated that they viewed the reporting and recordkeeping requirements as an unnecessary and expensive burden on both the coating manufacturers and coating users. One commenter stated that monthly recordkeeping to determine compliance would be difficult due to the fact that paint is usually purchased in large volumes and delivered over a long period of time. Another commenter, a coatings supplier, presented a detailed plan for recordkeeping and reporting which is based on data contained in Occupational Safety and Health Administration's (OSHA's) Material Safety Data Sheet (MSDS). The major points of his proposal are as follows:

a. All coatings suppliers submit to users information on their coatings. Every coating, catalyst, reducer, and modifier shipped to the user is described in detail with an MSDS for each coating formulation.

b. Coatings suppliers keep records of all shipments made to each customer, usually by quarterly and annual basis, and many suppliers computerize this information.

c. The recordkeeping counterproposal is to switch from a monthly compliance determination to an annual event, or an "inventory day," somewhere near the end of the year.

d. By using the shipment records and subtracting inventory on hand, a total picture of VOC emissions is determined.

e. High technology industrial coatings are expensive and users will know to the nearest drum or gallon how much was purchased and how much is on hand, perhaps not on a monthly basis but on a quarterly or annual basis.

f. The reporting requirements can be implemented by the following steps:

(1) The coatings and solvent suppliers shall submit a form 20 OSHA approved MSDS with each composition sold to the user.

(2) The individual signing the MSDS for the coating or solvent supplier shall be responsible to the user for the accuracy of the information.

(3) The coatings and solvent suppliers can be asked to supply shipment information upon request of the user on an annual basis for purposes of determining compliance with the regulations.

(4) The user is responsible for the accuracy of the annual usage report of VOC-containing materials.

(5) The EPA may audit the data, but may request no records other than those already required by the IRS, DOT, OSHA, DOE, and the EPA itself under the Major Generator Provisions of the Resource Conservation and Recovery Act (RCRA).

As a result of this comment and others, EPA has been investigating alternative ways of reducing monitoring, recordkeeping, and reporting burdens on owners and operators. The goal is to reduce all recordkeeping and reporting that is not essential to determining compliance or to ensuring proper operation and maintenance. After reviewing the requirements in the proposed standards, EPA determined that monthly compliance tests, monitoring, and the compilation of monitoring data are essential for both the owner or operator and EPA to determine compliance and to ensure proper operation and maintenance. A responsible owner or operator would need monitoring information compiled in a usable form to determine when adjustments in the control system are needed to ensure that it is performing at its intended effectiveness level.

The proposed standard was written with the understanding that much of the data required to complete a compliance determination would be provided to the facility by the coating manufacturers. Some additional information, such as transfer efficiency and dilution solvent added at the plant, would be provided by the facility itself. It would appear that a facility manager would keep records of this type, even in the absence of any requirement to do so, to assure efficient materials utilization. EPA is therefore requiring only the additional step of filing the information in an accessible location. Because EPA judges that monthly compliance tests, monitoring, and recordkeeping are essential for determining compliance and proper operation and maintenance, these requirements have not been changed since proposal. It was judged, however, that reporting is not essential to EPA. In addition, when States are delegated the authority to enforce these standards, they may prefer either not to have reporting or to have reporting on a different schedule than EPA proposed. Therefore, the requirement to report violations of the standard and quarterly incineration reports have been removed since proposal. A State, however, at any time is free to impose its own reporting requirements in conjunction with this regulation.

The data supplied by the coating manufacturers may be in any format which is agreeable to the plant owner or operator. Likewise, the owner or operator may use any format in maintaining records as long as all the pertinent data is clearly identified, complete, and in the appropriate terms and units. As required in the regulation, a facility must maintain the records for a period of 2 years. Reports prepared for other agencies may be used for EPA requirements if the preceding conditions are met. Since this standard applies to the metal furniture industry, the coatings users and not suppliers are responsible to EPA for the completeness and accuracy of all reports and records.

Information Requirements Impacts

The reporting and recordkeeping requirements of the regulation are assessed in Standard Form 83 and supporting statement, which is included in the docket for public review (reference subcategory IV–H of docket number A–79–47). This documentation contains: (1) A description of the reporting and recordkeeping required by the regulation and the General Provisions, (2) the reasons for the requirements, and (3) an evaluation of the major alternatives considered (including the use of existing sources of information). Approximately 2,000 new, modified, or reconstructed affected

facilities are expected to be subject to the regulation through the first 5 years.

The regulation will require no reports in addition to those required under the General Provisions of 40 CFR Part 60. The General Provisions contain notification requirements that enable the Agency to keep abreast of facilities subject to the regulation and also contain requirements for the conduct and reporting of initial performance tests. Analysis of these reporting requirements indicates that they are both necessary and reasonable considering the savings in Agency time and resources required for effective enforcement.

The resources needed by the industry to maintain records and to collect, prepare, and use the reports through the first 5 years would be about 178 person-years. The resources required by EPA and State and local agencies to process the reports and to maintain records through the first 5 years would be about 8.5 person-years.

The Paperwork Reduction Act of 1980 (Pub. L. 95-511) requires clearance from the Office of Management and Budget (OMB) of certain public reporting/recordkeeping requirements before this rulemaking can be promulgated as final. The reporting/recordkeeping requirements associated with this standard have been approved by OMB, and have been assigned OMB control #2000-0649.

Regulatory Flexibility Analysis

This standard was proposed before January 1, 1981, and therefore is not subject to the requirements of the Regulatory Flexibility Act. However, during the development of the background information document for this standard, the economic impacts for representative small model plants were examined, and there were no significant impacts on these plants.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docket system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket, except for certain inter-Agency review materials, will serve as the record in case of judicial review (Section 307(d)(7)(A)).

Miscellaneous

The effective date of this regulation is October 29, 1982. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (November 28, 1980).

As prescribed by Section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to insure that cost was carefully considered in determining BDT. The economic impact assessment is included in the background information document for the proposed standards.

In addition to the economic impact analysis, the emission reduction and annualized cost for typical facilities expressed for each alternative in terms of dollars per ton of pollutant removed were compared to both the preceding alternative and to Alternative 1. For example, Alternative 4 was compared to Alternative 3 and Alternative 1.

Compared to the uncontrolled plant (Alternative 1), Alternative 2 (62 percent by volume solids coatings and 60 percent average transfer efficiency) results in an emission reduction of 29 megagrams (32 tons) of VOC per year. The annualized cost of Alternative 2 is $3,500 less than the annualized cost of Alternative 1 because of reduced material costs. This level of control results in a potential savings of $110 per ton of emissions reduced. Costs presented here are updated to July 1980 dollars.

Alternative 3 (70 percent by volume solids coatings and 60 percent average transfer efficiency) results in an emission reduction of 37.3 megagrams (41.1 tons) per year greater than Alternative 1. This level of control has an annualized cost of $28,000 less than Alternative 1 for a potential savings of $680 per ton of emissions reduced. Compared to Alternative 2 the application of Alternative 3 results in emission reductions of 8.26 megagrams (9.1 tons), has an annualized cost of $24,000 less, and a potential savings of $2,600 per ton of additional emission reduction.

Alternative 4 (waterborne coatings) results in an emission reduction of 40 megagrams (44.1 tons) per year greater than Alternative 1. This level of control has an annualized cost of $66,000 higher than Alternative 1 and results in a control cost of $1,500 per ton of emission reduction. Compared to Alternative 3, the application of Alternative 4 results in emission reductions of 2.72 megagrams (3.0 tons) per year, increases the annualized costs by $94,000 and has a control cost of $31,300 per ton of additional emission reductions.

In summary, both Alternatives 2 and 3 result in emission reductions and have a lower annualized cost than the uncontrolled plant. Alternative 2 was selected as the promulgated control level because of technological problems encountered with Alternative 3 control techniques. Alternative 4 was rejected because the cost of precluding the use of the much more cost-effective high solids coatings would be unreasonable in light of the amount of additional emission reduction that would be achieved by selecting the Alternative 4. Also, waterborne coatings are not demonstrated for application in all representative situations. Various other control techniques were quickly ruled out of consideration as BDT due to excessive control costs or technological limitations.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not "major" because: (1) The national annualized compliance costs, including capital charges resulting from the standards total less than $100 million; (2) the standards do not cause a major increase in prices or production costs; and (3) the

standards do not cause significant adverse effects on domestic competition, employment, investment, productivity, innovation or competition in foreign markets. This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are included in docket number A–79–47. The docket is available for public inspection at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc.

Dated: October 20, 1982.

Anne M. Gorsuch,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended by adding a new Subpart EE as follows:

Subpart EE—Standards of Performance for Surface Coating of Metal Furniture

Sec.

60.310 Applicability and designation of affected facility.
60.311 Definitions and symbols.
60.312 Standard for volatile organic compounds.
60.313 Performance tests and compliance provisions.
60.314 Monitoring of emissions and operations.
60.315 Reporting and recordkeeping requirements.
60.316 Test methods and procedures.

Authority: Sections 111 and 301(a) of the Clean Air Act, as amended, (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart EE—Standards of Performance for Surface Coating of Metal Furniture

§ 60.310 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each metal furniture surface coating operation in which organic coatings are applied.

(b) This subpart applies to each affected facility identified in paragraph (a) of this section on which construction, modification, or reconstruction is commenced after November 28, 1980.

§ 60.311 Definitions and symbols.

(a) All terms used in this subpart not defined below are given the meaning in the Act and in Subpart A of this part.

"Bake oven" means a device which uses heat to dry or cure coatings.

"Dip coating" means a method of applying coatings in which the part is submerged in a tank filled with the coatings.

"Electrodeposition (EDP)" means a method of applying coatings in which the part is submerged in a tank filled with the coatings and in which an electrical potential is used to enhance deposition of the coatings on the part.

"Electrostatic spray application" means a spray application method that uses an electrical potential to increase the transfer efficiency of the coatings.

"Flash-off area" means the portion of a surface coating operation between the coating application area and bake oven.

"Flow coating" means a method of applying coatings in which the part is carried through a chamber containing numerous nozzles which direct unatomized streams of coatings from many different angles onto the surface of the part.

"Organic coating" means any coating used in a surface coating operation, including dilution solvents, from which volatile organic compound emissions occur during the application or the curing process. For the purpose of this regulation, powder coatings are not included in this definition.

"Powder coating" means any surface coating which is applied as a dry powder and is fused into a continuous coating film through the use of heat.

"Spray application" means a method of applying coatings by atomizing and directing the atomized spray toward the part to be coated.

"Surface coating operation" means the system on a metal furniture surface coating line used to apply and dry or cure an organic coating on the surface of the metal furniture part or product. The surface coating operation may be a prime coat or a top coat operation and includes the coating application station(s), flash-off area, and curing oven.

"Transfer efficiency" means the ratio of the amount of coating solids deposited onto the surface of a part or product to the total amount of coating solids used.

"VOC content" means the proportion of a coating that is volatile organic compounds (VOC's), expressed as kilograms of VOC's per liter of coating solids.

"VOC emissions" means the mass of volatile organic compounds (VOC's), expressed as kilograms of VOC's per liter of applied coating solids, emitted from a metal furniture surface coating operation.

(b) All symbols used in this subpart not defined below are given the meaning in the Act and in Subpart A of this part

C_a = the VOC concentration in each gas stream leaving the control device and entering the atmosphere (parts per million by volume, as carbon)

C_b = the VOC concentration in each gas stream entering the control device (parts per million by volume, as carbon)

C_f = the VOC concentration in each gas stream emitted directly to the atmosphere (parts per million by volume, as carbon)

D_c = density of each coating, as received (kilograms per liter)

D_d = density of each diluent VOC-solvent (kilograms per liter)

D_r = density of VOC-solvent recovered by an emission control device (kilograms per liter)

E = VOC destruction efficiency of the control device (fraction)

F = the proportion of total VOC's emitted by an affected facility that enters the control device (fraction)

G = the volume-weighted average mass of VOC's in coatings consumed in a calendar month per unit volume of coating solids applied (kilograms per liter)

L_c = the volume of each coating consumed, as received (liters)

L_d = the volume of each diluent VOC-solvent added to coatings (liters)

L_r = the volume of VOC-solvent recovered by an emission control device (liters)

L_s = the volume of coating solids consumed (liters)

M_d = the mass of diluent VOC-solvent consumed (kilograms)

M_o = the mass of VOC's in coatings consumed, as received (kilograms)

M_r = the mass of VOC's recovered by an emission control device (kilograms)

N = the volume weighted average mass of VOC emissions to the atmosphere per unit volume of coating solids applied (kilograms per liter)

Q_a = the volumetric flow rate of each gas stream leaving the control device and entering the atmosphere (dry standard cubic meters per hour)

Q_b = the volumetric flow rate of each gas stream entering the control device (dry standard cubic meters per hour)

Q_f = the volumetric flow rate of each gas stream emitted directly to the atmosphere (dry standard cubic meters per hour)

R = the overall VOC emission reduction achieved for an affected facility (fraction)

T = the transfer efficiency (fraction)

V_s = the proportion of solids in each coating (or input stream), as received (fraction by volume)

W_o = the proportion of VOC's in each coating (or input stream), as received (fraction by weight)

§ 60.312 Standard for volatile organic compounds (VOC).

(a) On and after the date on which the initial performance test required to be conducted by § 60.8(a) is completed, no owner or operator subject to the provisions of this subpart shall cause the discharge into the atmosphere of VOC emissions from any metal furniture surface coating operation in excess of 0.90 kilogram of VOC per liter of coating solids applied.

§ 60.313 Performance tests and compliance provisions.

(a) Sections 60.8(d) and (f) do not apply to the performance test procedures required by this subpart.

(b) The owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8(a) and thereafter a performance test each calendar month for each affected facility according to the procedures in this section.

(c) The owner or operator shall use the following procedures for determining monthly volume-weighted average emissions of VOC's in kilograms per liter of coating solids applied (G).

(1) An owner or operator shall use the following procedures for any affected facility which does not use a capture system and control device to comply with the emissions limit specified under § 60.312. The owner or operator shall determine the composition of the coatings by formulation data supplied by the manufacturer of the coating or by an analysis of each coating, as received, using Reference Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the manufacturer of the coating to determine the VOC content of coatings using Reference Method 24. The owner or operator shall determine the volume of coating and the mass of VOC-solvent used for thinning purposes from company records on a monthly basis. If a common coating distribution system serves more than one affected facility or serves both affected and existing facilities, the owner or operator shall estimate the volume of coating used at each facility by using the average dry weight of coating and the surface area coated by each affected and existing facility or by other procedures acceptable to the Administrator.

(i) Calculate the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied (G) during each calendar month for each affected facility, except as provided under § 60.313(c)(2) and (c)(3). Each monthly calculation is considered a performance test. Except as provided in paragraph (c)(1)(iv) of this section, the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied (G) each calendar month will be determined by the following procedures.

(A) Calculate the mass of VOC's used ($M_o + M_d$) during each calendar month for each affected facility by the following equation:

$$M_o + M_d = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj}$$

($\Sigma L_{dj} D_{dj}$ will be 0 if no VOC solvent is added to the coatings, as received.)

Where: n is the number of different coatings used during the calendar month and m is the number of different diluent VOC-solvents used during the calendar month.

(B) Calculate the total volume of coating solids used (L_s) in each calendar month for each affected facility by the following equation:

$$L_s = \sum_{i=1}^{n} L_{ci} V_{si}$$

Where: n is the number of different coatings used during the calendar month.

Select the appropriate transfer efficiency from Table 1. If the owner or operator can demonstrate to the satisfaction of the Administrator that other transfer efficiencies other than those shown are appropriate, the Administrator will approve their use on a case-by-case basis. Transfer efficiency values for application methods not listed below shall be determined by the Administrator on a case-by-case basis. An owner or operator must submit sufficient data for the Administrator to judge the accuracy of the transfer efficiency claims.

TABLE 1.—TRANSFER EFFICIENCIES

Application methods	Transfer efficiency (T)
Air atomized spray	0.25
Airless spray	.25
Manual electrostatic spray	.60
Nonrotational automatic electrostatic spray	.70
Rotating head electrostatic spray (manual and automatic)	.80
Dip coat and flow coat	.90
Electrodeposition	.95

Where more than one application method is used within a single surface coating operation, the owner or operator shall determine the composition and volume of each coating applied by each method through a means acceptable to the Administrator and compute the weighted average transfer efficiency by the following equation:

$$T = \frac{\sum_{i=1}^{n} \sum_{k=1}^{p} L_{cik} V_{sik} T_k}{L_s}$$

Where n is the number of coatings used and p is the number of application methods used.

(C) Calculate the volume-weighted average mass of VOC's consumed per unit volume of coating solids applied (G) during the calendar month for each affected facility by the following equation:

$$G = \frac{M_o + M_d}{L_s T}$$

(ii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during the calendar month for each affected facility by the following equation:

$$N = G$$

(iii) Where the volume-weighted average mass of VOC discharged to the atmosphere per unit volume of coating solids applied (N) is less than or equal to 0.90 kilogram per liter, the affected facility is in compliance.

(iv) If each individual coating used by an affected facility has a VOC content, as received, which when divided by the lowest transfer efficiency at which the coating is applied, results in a value equal to or less than 0.90 kilogram per liter, the affected facility is in compliance provided no VOC's are added to the coatings during distribution or application.

(2) An owner or operator shall use the following procedures for any affected facility that uses a capture system and a control device that destroys VOC's (e.g., incinerator) to comply with the emission limit specified under § 60.312.

(i) Determine the overall reduction efficiency (R) for the capture system and control device. For the initial performance test the overall reduction efficiency (R) shall be determined as prescribed in (c)(2)(i) (A), (B), and (C) of this section. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency (R) for the performance test providing control device and capture system operating conditions have not changed. The procedure in (c)(2)(i) (A), (B), and (C), of this section, shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the initial performance test.

(A) Determine the fraction (F) of total VOC's emitted by an affected facility that enters the control device using the following equation:

$$F=\frac{\sum_{i=1}^{n} C_{bi} Q_{bi}}{\sum_{i=1}^{n} C_{bi} Q_{bi}+\sum_{j=1}^{m} C_{fj} Q_{fj}}$$

Where n is the number of gas streams entering the control device and m is the number of gas streams emitted directly to the atmosphere.

(B) Determine the destruction efficiency of the control device (E) using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation:

$$E=\frac{\sum_{i=1}^{n} Q_{bi} C_{bi}-\sum_{j=1}^{m} Q_{aj} C_{aj}}{\sum_{i=1}^{n} Q_{bi} C_{bi}}$$

Where: n is the number of gas streams entering the control device, and m is the number of gas streams leaving the contol device and entering the atmosphere.

(C) Determine overall reduction efficiency (R) using the following equation:

$R=EF$

(ii) Calculate the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each affected facility using equations in paragraphs (c)(1)(i) (A), (B), and (C) of this section.

(iii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month by the following equation:

$N=G(1-R)$

(iv) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.90 kilogram per liter of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

(3) An owner or operator shall use the following procedure for any affected facility which uses a control device that recovers the VOC's (e.g., carbon adsorber) to comply with the applicable emission limit specified under § 60.312.

(i) Calculate the total mass of VOC's consumed (M_o+M_d) and the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each affected facility using equations in paragraph (c)(1)(i) (A), (B), and (C) of this section.

(ii) Calculate the total mass of VOC's recovered (M_r) during each calender month using the following equation:

$M_r=L_rD_r$

(iii) Calculate overall reduction efficiency of the control device (R) for each calendar month for each affected facility using the following equation:

$$R=\frac{M_r}{M_o+M_d}$$

(iv) Calculate the volume-weighted average mass of VOC's emitted to the atmosphere (N) for each calendar month for each affected facility using equation in paragraph (c)(2)(iii) of this section.

(v) If the weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.90 kilogram per liter of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

§ 60.314 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility which uses a capture system and an incinerator to comply with the emission limits specified under § 60.312 shall install, calibrate, maintain, and operate temperature measurement devices according to the following procedures:

(1) Where thermal incineration is used, a temperature measurement device shall be installed in the firebox. Where catalytic incineration is used, a temperature measurement device shall be installed in the gas stream immediately before and after the catalyst bed.

(2) Each temperature measurement device shall be installed, calibrated, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of 0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C.

(3) Each temperature measurement device shall be equipped with a recording device so that a permanent continuous record is produced.

(b) The owner or operator of an affected facility which uses a capture system and a solvent recovery system to comply with the emission limits specified under § 60.312 shall install the equipment necessary to determine the total volume of VOC-solvent recovered daily.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.315 Reporting and recordkeeping requirements.

(a) The reporting requirements of Section 60.8(a) apply only to the initial performance test. Each owner or operator subject to the provisions of this subpart shall include the following data in the report of the initial performance test required under § 60.8(a):

(1) Except as provided in paragraph (a)(2) of this section, the volume-weighted average mass of VOC's emitted to the atmosphere per volume of applied coating solids (N) for a period of one calendar month from each affected facility.

(2) For each affected facility where compliance is determined under the provisions of § 60.313(c)(1)(iv), a list of the coatings used during a period of one calendar month, the VOC content of each coating calculated from data determined using Reference Method 24 or supplied by the manufacturer of the coating, and the minimum transfer efficiency of any coating application equipment used during the month.

(3) For each affected facility where compliance is achieved through the use of an incineration system, the following additional information will be reported:

(i) The proportion of total VOC's emitted that enters the control device (F),

(ii) The VOC reduction efficiency of the control device (E),

(iii) The average combustion temperature (or the average temperature upstream and downstream of the catalyst bed), and

(iv) A description of the method used to establish the amount of VOC's captured and sent to the incinerator.

(4) For each affected facility where compliance is achieved through the use of a solvent recovery system, the following additional information will be reported:

(i) The volume of VOC-solvent recovered (L_r), and

(ii) The overall VOC emission reduction achieved (R).

(b) Following the initial performance test, the owner or operator of an affected facility shall identify and record:

(1) Each instance in which the volume-weighted average of the total mass of VOC's emitted to the atmosphere per volume of applied

coating solids (N) is greater than the limit specified under § 60.312.

(2) Where compliance with § 60.312 is achieved through the use of thermal incineration, each 3-hour period when metal furniture is being coated during which the average temperature of the device was more than 28°C below the average temperature of the device during the most recent performance test at which destruction efficiency was determined as specified under § 60.313.

(3) Where compliance with § 60.312 is achieved through the use of catalytic incineration, each 3-hour period when metal furniture is being coated during which the average temperature of the device immediately before the catalyst bed is more than 28°C below the average temperature of the device immediately before the catalyst bed during the most recent performance test at which destruction efficiency was determined as specified under § 60.313. Additionally, when metal furniture is being coated, all 3-hour periods during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference across the catalyst bed during the most recent performance test at which destruction efficiency was determined as specified under § 60.313 will be recorded.

(c) Each owner or operator subject to the provisions of this subpart shall maintain at the source, for a period of at least 2 years, records of all data and calculations used to determine VOC emissions from each affected facility. Where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain, at the source, daily records of the incinerator combustion chamber temperature. If catalytic incineration is used, the owner or operator shall maintain at the source daily records of the gas temperature, both upstream and downstream of the incinerator catalyst bed. Where compliance is achieved through the use of a solvent recovery system, the owner or operator shall maintain at the source daily records of the amount of solvent recovered by the system for each affected facility.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.316 Test methods and procedures.

(a) The reference methods in Appendix A to this part except as provided under § 60.8(b) shall be used to determine compliance with § 60.312 as follows:

(1) Method 24, or coating manufacturer's formulation data, for use in the determination of VOC content of each batch of coating as applied to the surface of the metal parts. In case of an inconsistency between the Method 24 results and the formulation data, the Method 24 results will govern.

(2) Method 25 for the measurement of VOC concentration.

(3) Method 1 for sample and velocity traverses.

(4) Method 2 for velocity and volumetric flow rate.

(5) Method 3 for gas analysis.

(6) Method 4 for stack gas moisture.

(b) For Method 24, the coating sample must be at least a 1 liter sample in a 1 liter container taken at a point where the sample will be representative of the coating material as applied to the surface of the metal part.

(c) For Method 25, the minimum sampling time for each of 3 runs is 60 minutes and the minimum sample volume is 0.003 dry standard cubic meters except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) The Administrator will approve testing of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Metal Coil Surface Coating Operations

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2070-7]

Standards of Performance for New Stationary Sources; Metal Coil Surface Coating Operations

April 26, 1982.

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for metal coil surface coating operations were proposed in the Federal Register on January 5, 1981 (45 FR 1102). This action promulgates standards of performance for metal coil surface coating operations. These standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination that metal coil surface coating operations cause or contribute significantly to all pollution that may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed metal coil surface coating operations to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: November 1, 1982.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard (NSPS) is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Background Information Document.* The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Metal Coil Surface Coating Industry: Background Information for Promulgated Standards," EPA-450/3-80-035b. The BID contains (1) a summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final environmental impact statement (EIS), which summarizes the impacts of the standards.

Docket. A docket, number A-80-5, containing information considered by EPA in development of the promulgated standards is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Section Chief, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. EPA, Research Triangle Park, North Carolina 27711, telephone (919) 541-5578.

SUPPLEMENTARY INFORMATION: OMB Control Number: 2000-0660.

The Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> * * * Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact, and energy requirements) the Administrator determines has been adequately demonstrated (Section 111(a)(1)).

The standards apply to all new, modified, and reconstructed metal coil surface coating (coil coating) operations. Existing facilities are not subject to the standards unless they undergo a modification or a reconstruction as defined in 40 CFR 60.14 and 60.15. Compliance with the standards can be achieved by any of four approaches for each affected facility. The owner or operator can use coatings whose average volatile organic compound (VOC) content on a monthly basis is 0.28 kilograms per liter (kg/*l*) of coating solids applied or less; the owner or operator can apply higher VOC-content coatings if he reduces VOC emissions to 0.14 kg/*l* of coating solids applied or less; the owner or operator can comply by demonstrating an overall VOC emission reduction of 90 percent or greater prior to discharge to the atmosphere; or the owner or operator can comply by the combined use of low VOC-content coatings and higher VOC-content coatings with a control device to achieve a calculated monthly emission limit. The owner or operator using an incinerator to control VOC emissions is required to construct an enclosure of the coating application station during the test of incinerator efficiency to evaluate the capture efficiency of the control system.

The standards require each owner or operator to conduct monthly performance tests to demonstrate compliance with the proposed emission limits. Where coatings are used without a VOC capture system and emission control device to meet the numerical limit of 0.28 kg/*l* of coating solids applied, the owner or operator is required to calculate and record a weighted average of the VOC content of coatings applied (including dilution solvents) for each affected facility for each calendar month. Manufacturers' formulation data will normally be used for that purpose; Reference Method 24 will be used to resolve any disputes that may occur.

Where higher VOC-content coatings are used with a VOC capture system and emission control device to meet the numerical limit of 0.14 kg/*l* of coating solids applied, the owner or operator is required to calculate and record the weighted average of the VOC content (including dilution solvents) of coatings applied for each affected facility for each calendar month. During the initial performance tests, the owner or operator must measure the overall VOC emission reduction achieved by the VOC capture system and emission control device. Reference Method 25 and the equations provided in the standards are used for these determinations. Compliance is demonstrated where the overall VOC emission reduction is equal to or less than 0.14 kg/*l*.

Where compliance is achieved through the demonstration of a 90-percent overall reduction in VOC emissions, the owner or operator will conduct an initial performance test by using Reference Method 25 and the equations provided in the standards. Compliance is demonstrated where the overall percent reduction is equal to or greater than 90 percent. After the first monthly test, the owner or operator is required to monitor the operating parameters of the control device.

Where compliance is achieved by the combined use of low VOC-content coatings and higher VOC-content coatings with a control device, the owner or operator is required to calculate and record a weighted average VOC content of coatings applied (including dilution solvents) for each affected facility for each calendar month. Separate calculations must be made for coatings used without the control device in operation and for coatings used with the control device in operation. During the initial performance test, the owner or operator must measure the overall VOC emission reduction achieved by the capture

system and control device. The owner or operator is then required to calculate a monthly emission limit and the VOC emissions to the atmosphere to determine compliance.

If thermal incineration is used, the owner or operator is required to install and operate a device to monitor and record continuously the combustion temperature of the control device. The standards require the owner or operator to record all coating periods of more than 3 hours duration where the average combustion temperature falls 28° C (50° F) or more below the temperature at which compliance was demonstrated during the most recent measurement of incinerator efficiency. If catalytic incineration is used, the owner or operator is required to install a device to monitor and record continuously the gas temperature both upstream and downstream of the incinerator catalyst bed. The owner or operator is required to record all coating periods in excess of 3 hours where the average difference between the temperatures upstream and downstream of the catalyst bed falls below 80 percent of the temperature difference at which compliance was demonstrated during the most recent measurement of incinerator efficiency or where the average inlet (or upstream) temperature falls 28° C (50° F) or more below the inlet temperature at which compliance was demonstrated during the most recent measurement of incinerator efficiency.

Environmental, Energy, And Economic Impacts

The environmental, energy, and economic impacts of standards of performance are normally expressed as incremental differences between the impacts of complying with the proposed standards and those of complying with a typical State implementation plan (SIP). Many existing metal coil surface coating operations are located in areas that are considered nonattainment areas for purposes of achieving the national ambient air quality standard (NAAQS) for ozone. New facilities are expected to have the same geographic distribution as existing plants. States are in the process of revising their SIP's for these areas. In revising SIP's, States generally consider the recommendations contained in control techniques guidelines (CTG) documents. The CTG document applicable to this source category is "Control of Volatile Organic Emissions From Existing Stationary Sources, Volume II, Surface Coating of Cans, Coil, Paper, Fabrics, Automobiles, and Light-Duty Trucks," EPA-450/2-77-008 (CTG). Although the CTG documents are published for guidance only and are not legally binding on the States, impacts were estimated by assuming that most States will revise their existing SIP's in accordance with the CTG recommendations or retain their existing limits on VOC emission.

Approximately 70 percent of the existing coil coating plants are located in States that currently require VOC emissions to be reduced by at least 85 percent prior to discharge, except for plants that use waterborne or other low VOC-content coatings. This emission limit is more stringent than the CTG recommendations, and it appears that these States plan to maintain this level of control for VOC emissions. The ramaining plants are located in States that use a permit system for controlling VOC emissions. These States are expected to revise their SIP's to require VOC emission reductions to the CTG-recommended level, which is equivalent to a 64-percent reduction in the emissions from the average industry solvent-borne coating formulation of 60 percent VOC's and 40 percent solids by volume.

The standards would reduce VOC emissions from a typical plant by approximately 33 percent in States that currently control VOC emissions by a numerical limit (85-percent reduction) and reduce emissions from a typical plant by approximately 72 percent in States that adopt the CTG-recommended level of control (64-percent reduction). With no NSPS, nationwide VOC emissions from new plant capacity are projected to be 8,600 megagrams (Mg) per year after 5 years. Implementation of the NSPS would reduce these emissions by 6,000 Mg per year. In addition, after 5 years, the NSPS would also result in an emission reduction of 2,000 Mg per year from the control of existing plant capacity brought under the standards by modifications and reconstruction. Thus, the total fifth-year emission reduction resulting from implementation of the NSPS would be 8,000 Mg. An estimated 85 percent of new plants will use higher VOC-content coatings and incineration systems to comply with the standards, and the remaining 15 percent will use low VOC-content coating.

EPA recognizes that the estimated 8,000-Mg emission reduction is substantially greater than the 3,200 Mg estimate contained in the proposal preamble. The previous estimate was based on gross industry coating usage data that implied an average applied dry coating thickness of 0.025 millimeter (mm) or 0.001 in. (1 mil). A more reasonable approach is to estimate the emission reduction by using model plant data, which were the basis of cost and economic analyses and which used an average applied dry coating thickness of 1.8 mils. The 1.8-mil value was offered as typical by several industry sources and was subsequently approved by numerous industry reviewers of model plant data. The change in film thickness, plus rounding of model plant data to achieve consistency between costs and emission reduction estimates, results in the estimated fifth-year emission reduction of 8,000 Mg.

Little or no water pollution or solid waste impact from new, modified, or reconstructed coil coating plants is expected to result from application of the standards. None of the control techniques used by the coil coating industry generates either liquid or solid waste; therefore, the standards would have no impact in these areas.

Nationwide energy usage by the coil coating industry totaled about 6,600 terajoules (TJ) in 1978. The standards will result in an energy usage increase of about 1 percent per year, which is equivalent to 200,000 barrels of crude oil in the fifth year. Plants located in States requiring an 85-percent reduction and that achieve compliance through the use of higher VOC-content coatings in combination with an incinerator are expected to decrease their energy consumption by about 5 percent. However, for plants regulated to the CTG-recommended level of control, compliance with the standards through the use of incineration could result in as much as a 50-percent increase in energy consumption in some individual plants if one of the more energy-efficient systems identified as being capable of achieving the CTG-recommended limits is used as the baseline. Little or no impact in energy consumption is expected to result from the standards for plants meeting the emission limits with the use of waterborne or other low VOC-content coatings without the use of incineration.

The standards increase both the capital and annualized costs of new coil coating plants. Based on a predicted industry growth rate of 12 percent per year through 1985, the increased capital costs of new plants that locate in States requiring an 85-percent reduction in VOC emissions could range from $110,000 for a small plant to $140,000 for a large plant. This capital outlay represents an increase in the total capital costs of a new plant of approximately 1.4 percent for a small plant and 0.9 percent for a large plant. The increase in total annualized costs could range from $11,000 for a small plant to $23,000 for a large plant. For plants that locate in States that adopt

the CTG-recommended limits, capital costs for a new plant could increase by $160,000 for a small plant and by $920,000 for a large plant—2.3- and 6.6-percent increases, respectively, in the total capital costs of a new plant. Total annualized costs could increase by $55,000 for a small plant and by $395,000 for a large plant. Compliance with the standards could result in increases in the price of coil coated metal ranging from 0.2 percent for a large plant in 85-percent reduction areas to 4.1 percent for a large plant in States that adopt the CTG-recommended limits. The effects for other plant sizes fall between these two values.

During the first 5 years, the incremental capital costs of the NSPS are estimated to be approximately $18.8 million, and the incremental annualized costs in the fifth year are estimated at $5.4 million. These values are lower than those in the proposal preamble—$20.0 million and $7 million for the capital and annualized cost increments, respectively. The previous values were computed to show the maximum cost to the industry by assuming that all new plant capacity will use solvent-borne coatings and incineration as a means of complying with the standard. The lower estimates given above are based on the more realistic assumption that 15 percent of new plant capacity will comply with the standards by using waterborne coatings and thus incur no costs. This latter assumption is consistent with the estimates of emission reduction given above.

Cost estimates for plants in CTG areas are probably overstated by a substantial amount. These cost estimates were based on the least expensive devices that appear to be potentially capable of meeting CTG limits. In practice, however, these units are not now used. Rather, the predominant trend is toward use of modern heat recovery incineration systems. These systems, in addition to effectively reducing emissions, help to ensure a stable energy supply for coaters by using the coating solvents as fuel. The use of coating solvents as fuel is a benefit for which no credit is given in the economic analysis but that is important enough to cause many coil coaters to install the systems without a regulatory requirement.

The environmental, energy, and economic impacts are discussed in greater detail in the BID for the promulgated standards, "Metal Coil Surface Coating Industry—Background Information for Promulgated Standards of Performance," EPA-450/3-80-035b.

In addition to achieving emission reductions beyond those required by a typical SIP, standards of performance have other benefits. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries because they have less stringent air pollution standards than other States. Further, standards of performance provide documentation, which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. The costs are provided for an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact of controls on an industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** (45 FR 30686, May 9, 1980) of a meeting of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) to discuss the metal coil surface coating operations standards recommended for proposal. This meeting was held on June 4 and 5, 1980. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the **Federal Register** on January 5, 1981, (45 FR 1102). The preamble to the proposed standards discussed the availability of the proposal BID, "Metal Coil Surface Coating Industry—Background Information for Proposed Standards," EPA-450/3-80-035a, which describes in detail the regulatory alternatives considered and their impacts. Public comments were solicited at the time of proposal, and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on February 4, 1981, at Research Triangle Park, North Carolina. The hearing was open to the public, and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from February 4, 1981, to April 6, 1981.

Six comment letters were received and two interested parties testified at the public hearing concerning issues relative to the proposed standards of performance for metal coil surface coating operations. The comments have been carefully considered, and, where determined appropriate by the Administrator, changes have been made in the proposed standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from coil coaters, coating manufacturers, and Federal and State environmental agencies. A detailed discussion of these comments and responses can be found in the promulgation BID, "Metal Coil Surface Coating Industry: Background Information for Promulgated Standards of Performance," EPA-450/3-80-035b. The summary of comments and responses in the BID serves as the basis for the revisions that have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The comments have been divided into the following areas: General, Emission Control Technology, Environmental Impact, Legal Considerations, and Test Methods and Monitoring.

Significant changes in the standards since proposal involve compliance and reporting procedures. A procedure was added to the compliance provisions by which coil coaters can compute a monthly emission limit for affected facilities that control emissions by the combined use of low-solvent technology and higher solvent coatings with a control device. Reporting of monthly performance test data has been dropped from the standards, but owners and operators are required to record and maintain these data.

General

Two commenters questioned the need for an NSPS for coil coating, stating that, for economic reasons, new coil coating lines already employ the best technology for capturing VOC emissions to burn as fuel for their ovens and, therefore, do not contribute significantly to VOC emissions nationwide. They also questioned EPA's determination that coil coating contributes significantly to air pollution.

Section 111 of the Clean Air Act requires EPA to promulgate NSPS's for all source categories that contribute significantly to harmful air pollution (Section 111(b)(1), (f)(1)). Metal coil

coating is such a category (40 CFR 60.16 (Source Category No. 22); 44 FR 49222 (August 21, 1979)).

EPA recognizes that the recent trend in the coil coating industry has been toward the use of incineration with heat recovery as an energy conserving and economically attractive operating setup. EPA appreciates the emission reduction that has been achieved by this trend; however, promulgation of an NSPS is necessary to ensure that emission reductions reflecting best demonstrated technology (BDT) are achieved.

One commenter stated that EPA regulations covering VOC emissions from metal surface coating operations are inequitable in that the emission limits proposed for coil coating are more stringent than the limits proposed for other metal coating operations.

Section 111 requires that each NSPS reflect BDT for that source category. EPA uses the same approach in evaluating BDT for different source categories. The fact that the resulting emission limits are different for different source categories is irrelevant ("*Portland Cement Association* v. *Ruckelshaus*," 486 F.2d 375, 389 (D.C. Cir. 1973); "*National Lime Association* v. *EPA*," 627 F.2d 416, 447 n. 108 (D.C. Cir. 1980).

One respondent commented that the projected growth rate for coil coating used in the background study (12 percent per year) is too high and that a rate of 8 to 10 percent is more realistic.

The 12-percent per year growth rate mentioned in the background study is a misstatement of the growth rate used in the analyses. Total coating capacity was estimated to increase by a constant amount each year over a 5-year period. The increase used was equal to 12 percent of the total industry capacity in the baseline year. This is not equal to a 12-percent annual growth rate. Stated on a percentage basis, the annual growth rates assumed were 12 percent the first year, 10.7 percent the second year, 9.8 percent the third year, 9.0 percent the fourth year, and 8.5 percent the fifth year. Over the 5-year period, the average annual growth rate was approximately 10 percent per year. This growth rate is within the range of the growth rate values suggested by the commenter, and, therefore, EPA concludes that the projections in the background study are reasonable.

One commenter stated that he was unsure whether or not the standards permit a coater to use low VOC-content coatings that have a VOC content greater than 0.28 kg/l of coating solids in conjunction with other lower VOC-content coatings and to comply by computing the weighted average of the VOC contents.

The standards state that an affected facility is in compliance if each coating used has a VOC content less than or equal to 0.28 kg/l of coating solids or if the volume weighted average VOC content of all coatings used in a calendar month is less than or equal to 0.28 kg/l of coating solids. A procedure for computing the volume weighted average VOC content is provided in the standards. EPA considers that the concerns of the commenter are clearly covered in the standards as written and, therefore, made no changes to the wording of the standards in response to this comment.

One public hearing participant stated that the definition of "affected facility" should be changed from each coating operation to an entire coating line to permit averaging of the two coating operations on a tandem coil coating line. The public hearing participant later submitted this in a letter.

The choice of the affected facility for these standards is based on the Agency's interpretation of Section 111 of the Act and judicial construction of its meaning. Under Section 111, the NSPS must apply to "new sources"; "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" (Section 111(a)(3)). Most industrial plants, however, consist of numerous pieces or groups of equipment that emit air pollutants and that might be viewed as "sources." EPA therefore uses the term "affected facility" to designate the equipment, within a particular kind of plant, chosen as the "source" covered by given standards.

In choosing the affected facility, EPA must decide which pieces or groups of equipment are the appropriate units for separate emission standards. The Agency must do this in light of the terms and purpose of Section 111. One major consideration is that the use of a narrower definition results in bringing replacement equipment under the NSPS sooner. For example, if an entire plant were designated as the affected facility, no part of an existing plant would be subject to the standards unless the plant as a whole were "modified." If, on the other hand, each piece of equipment were designated as an affected facility, then, as each piece was replaced, it would be a new source subject to the standards. Because the purpose of Section 111 is to minimize emissions by the application of BDT (considering cost, other health and environmental effects, and energy requirements) at all new and modified sources, there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources would be subject to the standards as they are installed. This presumption can be overcome, however, if the Agency concludes that relevant statutory factors (technical feasibility, cost, energy, and other environmental impacts) point to a broader definition.

Designation of an entire coil coating line or an entire plant as an affected facility was considered in the development of the standards. These options were rejected in favor of designating each coating operation as an affected facility. In addition to the advantages cited above, this designation also simplifies recordkeeping and enforcement activities and, in many cases, gives added flexibility to owners or operators by allowing them to use different control technologies on each coating operation without the need for complicated averaging calculations.

One commenter stated that the definition of "coil coating" is too broad and would result in the regulation of many operations not considered in the development of the standards. The commenter suggested that the definition of "coil coating" be modified to exclude operations that process only metal with thicknesses less than 0.178 mm (0.007 in.), commonly considered to be metal foil, and to exclude operations covered by the proposed NSPS for can coating.

Metal foil is defined by the Aluminum Association as metal strip with a thickness less than 0.152 mm (0.006 in.). While metal foil fits the definition of metal coil contained in the proposed standards (i.e., a continuous metal strip packaged in a roll or coil), coating formulations, application rates, emissions, and process operations for foil are quite different from those for coil. In the background study for the coil coating standards, EPA did not evaluate foil processing operations nor identify BDT. Foil processing is therefore excluded from coverage under the coil coating standards. EPA has, therefore, modified the definition of "coil coating" to exclude operations that process only metal with a thickness less than 0.152 mm (0.006 in.). This cutoff point is based on the formal definition of "foil products" that is used by the aluminum industry and that was communicated to EPA by the Aluminum Association and verified by a major producer of foil products. EPA could find no basis for selecting 0.178 mm (0.007 in.) as a point of differentiation as suggested by the commenter. The comment regarding operations covered by the coil coating standards that are also covered by the can coating standards reflects a

misinterpretation of the coverage of the standards. Coil coating of can stock is covered by the coil coating standards but is excluded from coverage by the can surface coating standards.

One public hearing participant commented that affected facilities where waterborne coatings are used for a significant portion of the time, but where solvent-borne coatings are also used, should be allowed to meet the waterborne emission limit when waterborne coatings are used and the emission limit for solvent-borne coatings and a control device for the remainder of their coating operations. This method of compliance was not allowed by the proposed standards.

The few coil coating lines that are the basis for the comment use waterborne coatings for 80 to 90 percent of their coating operations and solvent-borne coatings for the remainder of the time. Incinerators for these lines are designed for the operation only when solvent-borne coatings are used and do not have heat recovery facilities. Where such incinerators are used to reduce emissions from waterborne coatings, previous EPA analyses indicate that energy costs are very high because of the required use of a large quantity of supplemental fuel and that emission reductions are small because of the low VOC concentration in the exhaust stream. The costs per unit of emission reduction achieved become exorbitant under these circumstances. Consequently, a procedure was added to the promulgated standards by which coil coaters can calculate an emission limit each month based on the relative amounts of coatings used with and without the emission control device in operation. Operators can then comply with the calculated VOC emission limit, which will have a value between 0.14 (or a 90-percent emission reduction) and 0.28 kg/l of coating solids applied, by the combination of waterborne coatings and solvent-borne coatings with a capture system and control device.

Two approaches were considered for this provision. Under the first approach (the one incorporated), owners or operators compute an affected facility's monthly emission limit, weighted according to the coating solids applied with each control technology, and then compute actual monthly emissions to determine compliance. Under the second approach, each affected facility would be required to achieve compliance with the emission limit for low VOC-content coatings (0.28 kg/l of coating solids applied) during the portion of the month when these coatings are used, and would be required to achieve compliance with the emission limit for higher VOC-content coatings and a control device (0.14 kg/l of coating solids applied, or a 90-percent emission reduction) for the portion of the month when this system is used.

The second approach has a disadvantage relative to the first one in that the averaging time over which compliance must be demonstrated may range from 1 day (or less) to a calendar month (~30 days). The established emission limits are based on a calendar month averaging time to allow owners or operators the flexibility of using coatings with a wide range of VOC content, which is very common in the industry, and still achieve compliance on a monthly basis. If the averaging time is reduced to less than a calendar month, the data may not support the emission limits now specified. In view of this disadvantage, the first approach was incorporated into the standards. The number of installations to which this provision applies is quite small, but the provision was determined necessary to allow particular installations to continue their normal operating patterns.

Emission Control Technology

One public hearing participant and one commenter stated that the emission limit for low VOC-content coatings contained in the proposed standards, 0.28 kg/l of coating solids applied, is too stringent and would stifle research and development activities in low-solvent technology. It was further stated that the emission limit in the proposed standards was based mainly on coatings applied to architectural and building products and that the technology was not demonstrated for all applications. Particular reference was made to the coating of can-end stock as requiring a separate emission limit for low-solvent technology.

EPA believes that the data obtained during the background study adequately demonstrate the availability of waterborne coatings that will meet the proposed emission limits for most applications. EPA did not identify any low VOC-content coatings applicable for coil coating can-end stock and does not know of any now in use. The coil coating lines identified during the background study that coat can-end stock all use solvent-borne coatings. In recent discussions, several coating manufacturers stated that they are now working on the development of waterborne coatings for can-end stock and that the operating requirements for this application pose difficult problems in reducing the VOC content of the coatings. Reasons cited for these problems include the limitations established by the U.S. Food and Drug Administration on the ingredients that can be used in such coatings and the severe stress that the coatings must withstand during the can-end forming process.

Some coating manufacturers have indicated that coatings for can-end stock with a VOC content in the range of 0.4 to 0.5 kg/l of coating solids may become available within the next few years, but they do not expect the levels of VOC content to be much below this range. Emissions from such coatings would be substantially greater than emissions from other coil coating operations that use either low VOC-content coatings or higher VOC-content coatings and incineration.

Because the use of higher VOC-content coatings with a control device has been determined to be technically and economically feasible and not exorbitantly costly, EPA has not established a separate emission limit for coil coating of can-end stock.

One commenter suggested that, instead of placing stringent emission limits on coil coaters, EPA should require other metal surface coating operations to change to the use of precoated coil as a more environmentally favorable process.

EPA has identified BDT (considering cost, other health and environmental effects, and energy requirements) for each metal surface coating operation and has based the standards for each operation on that technology. The Agency believes that this procedure is consistent with the provisions of Section 111 of the Clean Air Act. This comment addresses other surface coating NSPS's and does not question or cast any doubt on the appropriateness of the coil coating NSPS; therefore, no changes have been made as a result of this comment.

One commenter suggested that the proposed standards incorrectly emphasize the installation of incinerators over the use of low-solvent technology and stated that EPA did not consider low-solvent technology in the development of the standards. The commenter further stated that the energy analysis was flawed by incorrect assumptions related to coater room exhausts.

These comments were originally submitted at the NAPCTAC meeting in June 1980 and were resubmitted along with additional comments relating to the proposed standards. Subsequent to the NAPCTAC meeting and prior to proposal, EPA made changes to the standards in response to these

comments. Several additional regulatory alternatives were evaluated, and separate provisions were added to the standards relating to the use of low-solvent technology. As proposed, the standards allow compliance by either low-solvent technology or incineration. The comment regarding consideration of low-solvent technology is therefore not applicable. Changes were also made to the provisions relating to coater rooms. As a result, the coater room exhaust is no longer required to enter the oven or control device. The energy-related comment referring to the coater room exhaust requirement also no longer applies. EPA therefore believes that an adequate response has been made to these comments and that they do not pertain to the proposed standards.

Environmental Impact

One commenter stated that the draft EIS in the proposal BID may understate final emission levels by a factor of 2 because incinerators are only capable of achieving a 90-percent reduction in VOC emissions rather than the 95-percent reduction assumed in the development of the draft EIS.

EPA believes that the emission test data presented in the proposal BID adequately demonstrate the ability of incinerators to reduce emissions by 95 percent when operated at a temperature of 760° C (1,400° F) or more. This conclusion is based on emission tests at four plants where the incinerators were operated at 760° C (1,400° F) or greater and that achieved an emission reduction of 95 percent or greater and on tests at a fifth plant where an emission reduction of 95 percent or more was achieved at temperatures below 760° C (1,400° F). These data are itemized in Chapter 4 of the proposal BID.

Legal Considerations

One commenter stated that EPA's raw data base for the proposed standards is inadequate and was not based on Reference Method 25 testing.

The standards are based on the Reference Method 25 test conducted by EPA during the background study. This test showed a 95-percent reduction across the incinerator at a temperature of 760° C (1,400° F). During that test, a continuous flame ionization detector (FID) was also used to measure VOC concentration in the incinerator outlet. The FID measurements consistently showed an emission reduction of approximately 99 percent at 760° C (1,400° F). There are other test data available that were obtained with an FID. In all these tests where the incinerator was operated at 760° C (1,400° F) or greater, the FID data consistently show an emission reduction of approximately 99 percent. These other data reinforce the validity of selecting 95 percent as the standard based on Reference Method 25 measurements.

Test Methods and Monitoring

One commenter believes that Reference Method 25 is inappropriate as the only method for compliance testing because it is virtually unavailable to any source outside the Los Angeles area, where the air pollution control district owns the equipment and performs the tests, or outside the service area of a single commercial laboratory in the Midwest capable of carrying out the technique.

There are at least five commercial laboratories in the Midwest and Northeast that are capable of performing compliance tests using Reference Method 25. Most of these laboratories are capable of supplying testing services to any region of the country.

One commenter stated that Reference Method 25 is highly laboratory oriented and requires extensive capital investment if individual sources must prepare to carry out the testing procedure. This commenter further stated that Reference Method 25 is subject to criticism for potential bias; that no suppliers exist for an instrument to handle analyses of Reference Method 25 test samples; and that, while one U.S. company has offered an instrument for sale, it has not performed reliably.

At least one company has already built a prototype instrument, which has functioned reliably as the nonmethane organic analyzer described in Reference Method 25. In addition, there are now a number of commercial laboratories capable of supplying this service.

One commenter was particularly concerned with the inability of Reference Method 25 to account for the bias that can be introduced by particulate matter, such as a flake of paint or a droplet of condensed hydrocarbon.

Although organic particulate matter could be a potential problem if it were collected in the Reference Method 25 sampling train, this can be easily prevented by including a filter in the sample train upstream of the cold traps. Using a filter is an option that is permitted in Method 25.

One commenter believes that alternative test procedures are available by which direct measurement can be made of total gaseous organic compounds with an FID. This method has adequately demonstrated the ability to monitor emissions on a real-time basis—an ability particularly important for cyclic processes or those that do not emit a uniform level of pollutants. The commenter, therefore, urged that the Agency consider substituting a more suitable method or, at least, providing for one or more alternative methods. The commenter offered to provide documentation and detail of the method considered superior and practical.

EPA is presently developing a procedure using a flame ionization analyzer that may be used as an alternative method in certain cases. It will be permitted as an alternative procedure for determining the efficiency of control devices on coating operations if the analyzer is calibrated with the solvent material used in the coating process. This procedure will be available for use as an alternative procedure as soon as it is published in the Federal Register in its final form and the necessary changes have been made in the appropriate regulations.

In the meantime, one can apply under § 60.8(b) for alternative method status. All that is required is that one submit a detailed written procedure for the candidate method and data comparing the candidate method and the reference method.

A comment received during the development of another surface coating standard questioned the relationship of the proposed standards and the use of Reference Method 24 for determining compliance. The commenter stated that the proposed standards should include a "cushion" that would allow for differences in test results caused by variations in the three experimentally determined parameters used to calculate VOC content of coatings.

Upon evaluation, EPA determined that this comment is equally applicable to the coil coating regulation.

EPA recognizes the potential variability in the results when Reference Method 24 is used to analyze water-based coatings. The method itself contains a procedure to account for this variability. The promulgated standards require that, when Reference Method 24 results are used to determine compliance, they be adjusted as described in Section 4.4 of Reference Method 24. This adjustment applies only to waterborne coatings.

If the actual VOC level of a waterborne coating is at or below the standard, there is less than 1 chance in 10,000 that the Reference Method 24 adjusted results will show the VOC levels to be above the standard.

One commenter challenged the use of the terms "total enclosure" and "total capture of VOC emissions" in the proposed test procedure for incinerators.

stating that there is no such thing as total enclosure and total capture.

EPA agrees that, taken literally, the terms "total enclosure" and "total capture of VOC emissions" describe conditions that are extremely difficult to achieve. Although these terms were used in a practical engineering sense, a literal interpretation could lead to both compliance and enforcement difficulties. In view of this possibility, EPA has changed the wording of the test procedure to eliminate the two terms and has replaced them with a requirement that coating station enclosures be maintained at a negative pressure to achieve good capture of VOC emissions.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA's responses to significant comments, the contents of the docket will serve as the record in case of judicial review (Section 307(d)(7)(A)).

Miscellaneous

The effective date of this regulation is November 1, 1982. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (January 5, 1981).

As prescribed by Section 111, establishment of standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

The rulemaking process that implements performance standards ensures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which Government resources are applied in a well-publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in this regulation will be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining BDT. The economic impact assessment is included in the BID for the proposed standards.

In addition to conducting an economic impact analysis, EPA examined the emission reduction and annualized costs—expressed in dollars per ton of pollutant removed per year—for three levels of control in typical plants. The three levels of control are an overall emission reduction of 64 percent, as recommended by the CTG; an overall emission reduction of 85 percent, as specified in many existing SIP's; and an overall emission reduction of 90 percent, as contained in the NSPS. This examination showed that an 85-percent level of control reduces emissions by 174 Mg (192 tons) per year relative to the CTG recommendation and increases annualized costs by $982/Mg ($890/ton). It also showed that the incremental emission reduction achieved by increasing the control level from 85 to 90 percent is 41 Mg (45 tons) per year at an annualized cost of $668/Mg ($609 ton). These annualized costs per ton of pollutant removed are comparable to costs and associated emission reductions in other industries that control VOC emissions.

The Paperwork Reduction Act of 1980 (Pub. L. 95-511) requires EPA to submit to the Office of Management and Budget (OMB) certain public reporting/recordkeeping requirements before proposal. The reporting/recordkeeping requirements associated with this standard have been submitted to OMB for approval, and have been assigned Control No. 2000-0660.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a regulatory impact analysis. This regulation is not major because it would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be major. The industry wide annualized costs in the fifth year after the standards would go into effect would be $5.4 million, much less than the $100 million established as the first criterion for a major regulation in the Order. The estimated price increase of less than 3 percent associated with the proposed standards would not be considered a "major increase in costs or prices" specified as the second criterion in the Order. The economic analysis of the proposed standards' effects on the industry did not indicate any significant adverse effects on competition, investment, productivity, employment, innovation, or the ability of U.S. firms to compete with foreign firms (the third criterion in the Order).

This regulation was submitted to OMB for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are available for public inspection in the docket referenced in the address section of this preamble.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc.

Dated: October 20, 1982.

Anne M. Gorsuch,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended by adding a new Subpart TT as follows:

Subpart TT—Standards of Performance for Metal Coil Surface Coating

Sec.

60.460 Applicability and designation of affected facility.
60.461 Definitions.

Sec.
60.462 Standards for volatile organic compounds.
60.463 Perfomance test and compliance provisions.
60.464 Monitoring of emissions and operations.
60.465 Reporting and recordkeeping requirements.
60.466 Test methods and procedures.

Authority: Sections 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart TT—Standards of Performance for Metal Coil Surface Coating

§ 60.460 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in a metal coil surface coating operation: each prime coat operation, each finish coat operation, and each prime and finish coat operation combined when the finish coat is applied wet on wet over the prime coat and both coatings are cured simultaneously.

(b) This subpart applies to any facility identified in paragraph (a) of this section that commences construction, modification, or reconstruction after January 5, 1981.

§ 60.461 Definitions.

(a) All terms used in this subpart not defined below are given the same meaning as in the Act or in Subpart A of this part.

"Coating" means any organic material that is applied to the surface of metal coil.

"Coating application station" means that portion of the metal coil surface coating operation where the coating is applied to the surface of the metal coil. Included as part of the coating application station is the flashoff area between the coating application station and the curing oven.

"Curing oven" means the device that uses heat or radiation to dry or cure the coating applied to the metal coil.

"Finish coat operation" means the coating application station, curing oven, and quench station used to apply and dry or cure the final coating(s) on the surface of the metal coil. Where only a single coating is applied to the metal coil, that coating is considered a finish coat.

"Metal coil surface coating operation" means the application system used to apply an organic coating to the surface of any continuous metal strip with thickness of 0.15 millimeter (mm) (0.006 in.) or more that is packaged in a roll or coil.

"Prime coat operation" means the coating application station, curing oven, and quench station used to apply and dry or cure the initial coating(s) on the surface of the metal coil.

"Quench station" means that portion of the metal coil surface coating operation where the coated metal coil is cooled, usually by a water spray, after baking or curing.

"VOC content" means the quantity, in kilograms per liter of coating solids, of volatile organic compounds (VOC's) in a coating.

(b) All symbols used in this subpart not defined below are given the same meaning as in the Act and in Subpart A of this part.

C_a = the VOC concentration in each gas stream leaving the control device and entering the atmosphere (parts per million by volume, as carbon).
C_b = the VOC concentration on each gas stream entering the control device (parts per million by volume, as carbon).
C_f = the VOC concentration in each gas steam emitted directly to the atmosphere (parts per million by volume, as carbon).
D_c = density of each coating, as received (kilograms per liter).
D_d = density of each VOC-solvent added to coatings (kilograms per liter).
D_r = density of VOC-solvent recovered by an emission control device (kilograms per liter).
E = VOC destruction efficiency of the control device (fraction).
F = the proportion of total VOC's emitted by an affected facility that enters the control device (fraction).
G = volume-weighted average mass of VOC's in coatings consumed in a calendar month per unit volume of coating solids applied (kilograms per liter).
L_c = the volume of each coating consumed, as received (liters).
L_d = the volume of each VOC-solvent added to coatings (liters).
L_r = the volume of VOC-solvent recovered by an emission control device (liters).
L_s = the volume of coating solids consumed (liters).
M_d = the mass of VOC-solvent added to coatings (kilograms).
M_c = the mass of VOC's in coatings consumed, as received (kilograms).
M_r = the mass of VOC's recovered by an emission control device (kilograms).
N = the volume-weighted average mass of VOC emissions to the atmosphere per unit volume of coating solids applied (kilograms per liter).
Q_a = the volumetric flow rate of each gas stream leaving the control device and entering the atmosphere (dry standard cubic meters per hour).
Q_b = the volumetric flow rate of each gas stream entering the control device (dry standard cubic meters per hour).
Q_f = the volumetric flow rate of each gas steam emitted directly to the atmosphere (dry standard cubic meters per hour).
R = the overall VOC emission reduction achieved for an affected facility (fraction).
S = the calculated monthly allowable emission limit (kilograms of VOC per liter of coating solids applied).
V_s = the proportion of solids in each coating, as received (fraction by volume).
W_o = the proportion of VOC's in each coating, as received (fraction by weight).

§ 60.462 Standards for volatile organic compounds.

(a) On and after the date on which § 60.8 requires a performance test to be completed, each owner or operator subject to this subpart shall not cause to be discharged into the atmosphere more than:

(1) 0.28 kilogram VOC per liter (kg VOC/*l*) of coating solids applied for each calendar month for each affected facility that does not use an emission control device(s); or

(2) 0.14 kg VOC/*l* of coating solids applied for each calendar month for each affected facility that continuously uses an emission control device(s) operated at the most recently demonstrated overall efficiency; or

(3) 10 percent of the VOC's applied for each calendar month (90 percent emission reduction) for each affected facility that continuously uses an emission control device(s) operated at the most recently demonstrated overall efficiency; or

(4) a value between 0.14 (or a 90-percent emission reduction) and 0.28 kg VOC/*l* of coating solids applied for each calendar month for each affected facility that intermittently uses an emission control device operated at the most recently demonstrated overall efficiency.

§ 60.463 Performance test and compliance provisions.

(a) Sections 60.8 (d) and (f) do not apply to the performance test.

(b) The owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8(a) and thereafter a performance test for each calendar month for each affected facility according to the procedures in this section.

(c) The owner or operator shall use the following procedures for determining monthly volume-weighted average emissions of VOC's in kg/*l* of coating solids applied.

(1) An owner or operator shall use the following procedures for each affected facility that does not use a capture system and control device to comply with the emission limit specified under § 60.462(a)(1). The owner or operator shall determine the composition of the coatings by formulation data supplied by the manufacturer of the coating or by an analysis of each coating, as received

using Reference Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the manufacturer of the coatings to determine the VOC content of coatings using Reference Method 24 or an equivalent or alternative method. The owner or operator shall determine the volume of coating and the mass of VOC-solvent added to coatings from company records on a monthly basis. If a common coating distribution system serves more than one affected facility or serves both affected and existing facilities, the owner or operator shall estimate the volume of coating used at each affected facility by using the average dry weight of coating and the surface area coated by each affected and existing facility or by other procedures acceptable to the Administrator.

(i) Calculate the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied during each calendar month for each affected facility, except as provided under § 60.463(c)(1)(iv). The weighted average of the total mass of VOC's used per unit volume of coating solids applied each calendar month is determined by the following procedures.

(A) Calculate the mass of VOC's used (Mo+Md) during each calendar month for each affected facility by the following equation:

$$M_o+M_d=\sum_{i=1}^{n} L_{oi}D_{ci}W_{oi}+\sum_{j=1}^{m} L_{sj}D_{sj}$$

($\Sigma L_{sj}D_{sj}$ will be 0 if no VOC solvent is added to the coatings, as received)

where

n is the number of different coatings used during the calendar month, and

m is the number of different VOC solvents added to coatings used during the calendar month.

(B) Calculate the total volume of coating solids used (L_s) in each calendar month for each affected facility by the following equation:

$$L_s=\sum_{i=1}^{n} V_{oi}L_{oi}$$

where

n is the number of different coatings used during the calendar month.

(C) Calculate the volume-weighted average mass of VOC's used per unit volume of coating solids applied (G) during the calendar month for each affected facility by the following equation:

$$G=\frac{M_o+M_d}{L_s}$$

(ii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during the calendar month for each affected facility by the following equation:

N=G

(iii) Where the volume-weighted average mass of VOC's discharged to the atmosphere per unit volume of coating solids applied (N) is equal to or less than 0.28 kg/l, the affected facility is in compliance.

(iv) If each individual coating used by an affected facility has a VOC content, as received, that is equal to or less than 0.28 kg/l of coating solids, the affected facility is in compliance provided no VOC's are added to the coatings during distribution or application.

(2) An owner or operator shall use the following procedures for each affected facility that continuously uses a capture system and a control device that destroys VOC's (e.g., incinerator) to comply with the emission limit specified under § 60.462(a) (2) or (3).

(i) Determine the overall reduction efficiency (R) for the capture system and control device.

For the initial performance test, the overall reduction efficiency (R) shall be determined as prescribed in paragraphs (c)(2)(i) (A), (B), and (C) of this section. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency (R) for the performance test, providing control device and capture system operating conditions have not changed. The procedure in paragraphs (c)(2)(i) (A), (B), and (C) of this section, shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the initial performance test.

(A) Determine the fraction (F) of total VOC's emitted by an affected facility that enters the control device using the following equation:

$$F=\frac{\sum_{i=1}^{l} C_{ai}Q_{ai}}{\sum_{i=1}^{l} C_{ai}Q_{ai}+\sum_{j=1}^{p} C_{aj}Q_{aj}}$$

where

l is the number of gas streams entering the control device, and

p is the number of gas streams emitted directly to the atmosphere.

(B) Determine the destruction efficiency of the control device (E) using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation:

$$E=\frac{\sum_{i=1}^{n} Q_{bi}C_{bi}-\sum_{j=1}^{m} Q_{aj}C_{aj}}{\sum_{i=1}^{n} Q_{bi}C_{bi}}$$

where

n is the number of gas streams entering the control device, and

m is the number of gas streams leaving the control device and entering the atmosphere.

The owner or operator of the affected facility shall construct the VOC emission reduction system so that all volumetric flow rates and total VOC emissions can be accurately determined by the applicable test methods and procedures specified in § 60.468. The owner or operator of the affected facility shall construct a temporary enclosure around the coating applicator and flashoff area during the performance test for the purpose of evaluating the capture efficiency of the system. The enclosure must be maintained at a negative pressure to ensure that all VOC emissions are measurable. If a permanent enclosure exists in the affected facility prior to the performance test and the Administrator is satisfied that the enclosure is adequately containing VOC emissions, no additional enclosure is required for the performance test.

(C) Determine overall reduction efficiency (R) using the following equation:

R=EF

If the overall reduction efficiency (R) is equal to or greater than 0.90, the affected facility is in compliance and no further computations are necessary. If the overall reduction efficiency (R) is less than 0.90, the average total VOC emissions to the atmosphere per unit volume of coating solids applied (N) shall be computed as follows.

(ii) Calculate the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each

affected facility using equations in paragraphs (c)(1)(i) (A), (B), and (C) of this section.

(iii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month by the following equation:

$$N = G(1 - R)$$

(iv) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.14 kg// of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

(3) An owner or operator shall use the following procedure for each affected facility that uses a control device that recovers the VOC's (e.g., carbon adsorber) to comply with the applicable emission limit specified under § 60.462(a) (2) or (3).

(i) Calculate the total mass of VOC's consumed ($M_o + M_a$) during each calendar month for each affected facility using equation (1).

(ii) Calculate the total mass of VOC's recovered (M_r) during each calendar month using the following equation:

$$M_r = L_a D_a$$

(iii) Calculate the overall reduction efficiency of the control device (R) for each calendar month for each affected facility using the following equation:

$$R = \frac{M_r}{M_o + M_a}$$

If the overall reduction efficiency (R) is equal to or greater than 0.90, the affected facility is in compliance and no further computation are necessary. If the overall reduction efficiency (R) is less than 0.90, the average total VOC emissions to the atmosphere per unit volume of coating solids applied (N) must be computed as follows.

(iv) Calculate the total volume of coating solids consumed (L_{ca}) and the volume-weighted average of the total mass of VOC's per unit volume of coating solids applied (G) during each calendar month for each affected facility using equations in paragraphs (c)(1)(i) (B) and (C) of this section.

(v) Calculate the volume-weighted average mass of VOC's emitted to the atmosphere (N) for each calendar month for each affected facility using equation (8).

(vi) If the weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to 0.14 kg// of coating solids applied, the affected facility is in compliance. Each monthly calculation is a performance test.

(4) An owner or operator shall use the following procedures for each affected facility that intermittently uses a capture system and a control device to comply with the emission limit specified in § 60.462(a)(4).

(i) Calculate the total volume of coating solids applied without the control device in operation (L_{oa}) during each calendar month for each affected facility using the following equation:

$$L_{oa} = \sum_{i=1}^{n} V_{oi} L_{oi}$$

where

n is the number of coatings used during the calendar month without the control device in operation.

(ii) Calculate the total volume of coating solids applied with the control device in operation (L_{ca}) during each calendar month for each affected facility using the following equation:

$$L_{ca} = \sum_{i=1}^{m} V_{ai} L_{ai}$$

where

m is the number of coatings used during the calendar month with the control device in operation.

(iii) Calculate the mass of VOC's used without the control device in operation ($M_{oa} + M_{oa}$) during each calendar month for each affected facility using the following equation:

$$M_{oa} + M_{oa} = \sum_{i=1}^{n} L_{oi} D_{oi} W_{oi} + \sum_{j=1}^{m} L_{oj} D_{oj}$$

where

n is the number of different coatings used without the control device in operation during the calendar month, and

m is the number of different VOC-solvents added to coatings used without the control device in operation during the calendar month.

(iv) Calculate the volume-weighted average of the total mass of VOC's consumed per unit volume of coating solids applied without the control device in operation (G_n) during each calendar month for each affected facility using the following equation:

$$G_n = \frac{M_{oa} + M_{oa}}{L_{oa}}$$

(v) Calculate the mass of VOC's used with the control device in operation ($M_{ca} + M_{ca}$) during each calendar month for each affected facility using the following equation:

$$M_{ca} + M_{ca} = \sum_{i=1}^{n} L_{ai} D_{ai} W_{ai} + \sum_{j=1}^{m} L_{aj} D_{aj}$$

where

n is the number of different coatings used with the control device in operation during the calendar month, and

m is the number of different VOC-solvents added to coatings used with the control device in operation during the calendar month.

(vi) Calculate the volume-weighted average of the total mass of VOC's used per unit volume of coating solids applied with the control device in operation (G_c) during each calendar month for each affected facility using the following equation:

$$G_c = \frac{M_{ca} + M_{ca}}{L_{ca}}$$

(vii) Determine the overall reduction efficiency (R) for the capture system and control device using the procedures in § 60.463(c)(2)(i) (A), (B), and (C) or § 60.463(c)(3) (i), (ii), and (iii), which is applicable.

(viii) Calculate the volume-weighted average of VOC emissions to the atmosphere (N) during each calendar month for each affected facility using the following equation:

$$N=\frac{G_n L_{sn}+G_c L_{sc}(1-R)}{L_{sn}+L_{sc}}$$

(ix) Calculate the emission limit(s) for each calendar month for each affected facility using the following equation:

$$S=\frac{0.28\,L_{sn}+0.1\,G_c L_{sc}}{L_{sn}+L_{sc}} \text{ or } \frac{0.28\,L_{sn}+0.14\,L_{sc}}{L_{sn}+L_{sc}},$$

which is greater.

(x) If the volume-weighted average mass of VOC's emitted to the atmosphere for each calendar month (N) is less than or equal to the calculated emission limit (S) for the calendar month, the affected facility is in compliance. Each monthly calculation is a performance test.

§ 60.464 Monitoring of emissions and operations.

(a) Where compliance with the numerical limit specified in § 60.462(a) (1) or (2) is achieved through the use of low VOC-content coatings without the use of emission control devices or through the use of higher VOC-content coatings in conjunction with emission control devices, the owner or operator shall compute and record the average VOC content of coatings applied during each calendar month for each affected facility, according to the equations provided in § 60.463.

(b) Where compliance with the limit specified in § 60.462(a)(4) is achieved through the intermittent use of emission control devices, the owner or operator shall compute and record for each affected facility the average VOC content of coatings applied during each calendar month according to the equations provided in § 60.463.

(c) If thermal incineration is used, each owner or operator subject to the provisions of this subpart shall install, calibrate, operate, and maintain a device that continuously records the combustion temperature of any effluent gases incinerated to achieve compliance with § 60.462(a) (2), (3), or (4). This device shall have an accuracy of ±2.5° or ±0.75 percent of the temperature being measured expressed in degrees Celsius, which is greater. Each owner or operator shall also record all periods (during actual coating operations) in excess of 3 hours during which the average temperature in any thermal incinerator used to control emissions from an affected facility remains more than 28° C (50° F) below the temperature at which compliance with § 60.462(a) (2), (3), or (4) was demonstrated during the most recent measurement of incinerator efficiency required by § 60.8. The records required by § 60.7 shall identify each such occurrence and its duration. If catalytic incineration is used, the owner or operator shall install, calibrate, operate, and maintain a device to monitor and record continuously the gas temperature both upstream and downstream of the incinerator catalyst bed. This device shall have an accuracy of ±2.5° C or ±0.75 percent of the temperature being measured expressed in degrees Celsius, whichever is greater. During coating operations, the owner or operator shall record all periods in excess of 3 hours where the average difference between the temperature upstream and downstream of the incinerator catalyst bed remains below 80 percent of the temperature difference at which compliance was demonstrated during the most recent measurement of incinerator efficiency or when the inlet temperature falls more than 28° C (50° F) below the temperature at which compliance with § 60.462(a) (2), (3), or (4) was demonstrated during the most recent measurement of incinerator efficiency required by § 60.8. The records required by § 60.7 shall identify each such occurrence and its duration.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.465 Reporting and recordkeeping requirements.

(a) Where compliance with the numerical limit specified in § 60.462(a) (1), (2), or (4) is achieved through the use of low VOC-content coatings without emission control devices or through the use of higher VOC-content coatings in conjunction with emission control devices, each owner or operator subject to the provisions of this subpart shall include in the initial compliance report required by § 60.8 the weighted average of the VOC content of coatings used during a period of one calendar month for each affected facility. Where compliance with § 60.462(a)(4) is achieved through the intermittent use of a control device, reports shall include separate values of the weighted average VOC content of coatings used with and without the control device in operation.

(b) Where compliance with § 60.462(a) (2), (3), or (4) is achieved through the use of an emission control device that destroys VOC's, each owner or operator subject to the provisions of this subpart shall include the following data in the initial compliance report required by § 60.8:

(1) The overall VOC destruction rate used to attain compliance with § 60.462(a) (2), (3), or (4) and the calculated emission limit used to attain compliance with § 60.462(a)(4); and

(2) The combustion temperature of the thermal incinerator or the gas temperature, both upstream and downstream of the incinerator catalyst bed, used to attain compliance with § 60.462(a) (2), (3), or (4).

(c) Each owner or operator subject to the provisions of this subpart shall maintain at the source, for a period of at least 2 years, records of all data and calculations used to determine monthly VOC emissions from each affected facility and to determine the monthly emission limit, where applicable. Where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain, at the source, daily records of the incinerator combustion temperature. If catalytic incineration is used, the owner or operator shall maintain at the source daily records of the gas temperature, both upstream and downstream of the incinerator catalyst bed.

§ 60.466 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.462 as follows:

(1) Reference Method 24, or data provided by the formulator of the coating for determining the VOC content of each coating as applied to the surface of the metal coil. In the event of a dispute, Reference Method 24 shall be the reference method. When VOC content of waterborne coatings, determined by Reference Method 24, is used to determine compliance of affected facilities, the results of the Reference Method 24 analysis shall be adjusted as described in Section 4.4 of Reference Method 24;

(2) Reference Method 25, both for measuring the VOC concentration in each gas stream entering and leaving the control device on each stack equipped with an emission control device and for measuring the VOC concentration in each gas stream emitted directly to the atmosphere;

(3) Method 1 for sample and velocity traverses;

(4) Method 2 for velocity and volumetric flow rate;

(5) Method 3 for gas analysis; and

(6) Method 4 for stack gas moisture.

(b) For Method 24, the coating sample must be at least a 1-liter sample taken at a point where the sample will be representative of the coating as applied to the surface of the metal coil.

(c) For Method 25, the sampling time is to be at least 60 minutes, and the minimum sample volume is to be at least 0.003 dry standard cubic meter (DSCM); however, shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) The Administrator will approve testing of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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Part II

Environmental Protection Agency

Standards of Performance for New Stationary Sources—Graphic Arts Industry: Publication Rotogravure Printing

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2070-6]

Standards of Performance for New Stationary Sources—Graphic Arts Industry: Publication Rotogravure Printing

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for publication rotogravure printing presses were proposed in the Federal Register on October 28, 1980 (45 FR 71538). This action promulgates a standard of performance to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed publication rotogravure printing presses. Reference Method 24A is included with this promulgation. The standard implements Section 111 of the Clean Air Act and is based on the Administrator's determination that the graphic arts industry causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of the standard is to require all new, modified, and reconstructed publication rotogravure printing presses to control VOC emissions to the level achievable through use of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: November 8, 1982.

The incorporation by reference of the ASTM Standard listed in the regulations is approved by the Director of the Federal Register as of November 8, 1982.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 370(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Background Information Document.* The background information document (BID) for the promulgated standard may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Publication Rotogravure Printing—Background Information for Promulgated Standards" (EPA-450/3-80-031b). The BID contains (1) a summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the regulation since proposal. The final Environmental Impact Statement, which summarizes the impacts of the standards, is included in "Publication Rotogravure Printing—Background Information for Proposed Standards" (EPA-450/3-80-031a). The environmental impacts have not changed since proposal.

Docket. A docket, number A-79-50, containing information considered by EPA in development of the promulgated standard, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Section Chief, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5578.

SUPPLEMENTARY INFORMATION:

OMB Control number: 2000-0462.

The Standard

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standard applies to publication rotogravure production presses for which construction, reconstruction, or modification commenced after October 28, 1980. Definition of the terms "modification" and "reconstruction" are included in 40 CFR 60.14 and 60.15. Proof presses are not affected by the standard. Proof presses are used only to check the quality of the image formation of newly etched or engraved printing cylinders and do not print saleable items.

VOC emissions from publication rotogravure presses are limited to 16 percent of the total mass of VOC solvent and water used at the press.

Compliance with the emission limit must be demonstrated during a long-term performance test. The performance averaging period of each test is 30 consecutive calendar days instead of an average of three runs as prescribed under 40 CFR 60.8. Actual press emissions and the average control system performance are determined by a solvent mass balance. The total mass of recovered solvent is compared to the total mass of the solvent and water used at the press. If only solvent-borne are used, performance may be determined by a temperature/density-corrected solvent volume balance, at the option of the owner or operator. VOC content data for solvent-borne inks and related coatings are obtained from the ink manufacturer or determined by analysis with Reference Method 24A. VOC and water content data for waterborne inks and related coatings are obtained from the ink manufacturer. EPA is not promulgating a test method for analysis of waterborne printing inks. The calculated emission percentage can be reported as rounded-off to the nearest whole number.

The regulation includes compliance provisions based on the use of solvent-borne ink systems with a solvent vapor capture system and a fixed-bed carbon adsorption/solvent recovery system for VOC emission control. Provisions for compliance using waterborne inks have been included in expectation of future development of this low VOC emitting printing technique. Emission control equipment is not expected to be used with waterborne ink systems. When affected facilities are installed in plants with existing facilities, the owner or operator is allowed to choose among several compliance options for conducting performance tests.

After completion of the performance test, the owner or operator is required to monitor for proper operation and maintenance. The performance averaging period for monitoring is either a calendar month or a 4 consecutive week period, at the option of the owner or operator. Records of the amount of solvent and water used, solvent recovered, and the estimated emission percentage for each performance averaging period must be maintained for 2 years. No periodic reporting of the monthly monitoring results is required.

The emission limit can also be met through the use of other control techniques. Fluidized-bed carbon adsorption/solvent recovery systems

might be applied, but this method has not been successfully demonstrated in this industry. Regenerative cryogenic condensation/solvent recovery systems are becoming feasible on a commercial scale, but have not been tried in this industry. Solvent destruction (i.e., oxidation) control systems are used on other similar services, but are not desirable or necessary in this industry since the solvents used can be recovered in suitable enough condition to permit direct recycle to the presses. Specific procedures for determination of compliance with solvent destruction are not being promulgated since this control technique is not expected to be used on any new, modified, or reconstructed press.

Summary of Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts of the standard are expressed as incremental differences relative to a baseline level. A 75 percent overall VOC reduction efficiency, or 25 percent emission level, was chosen as the baseline for the impact analyses. This baseline level corresponds to the recommendation in EPA's control techniques guideline (CTG) document, "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume VIII: Graphic Arts—Rotogravure and Flexography" (EPA-450/2-78-033 [CTG]). The states are expected to use this document in developing their revised State Implementation Plans (SIP) for new and existing publication rotogravure printing facilities. If no NSPS were promulgated, new and existing facilities would be controlled to this baseline level by virtue of SIPs. The impact analyses compared impacts of new facilities under SIP control (i.e., in the absence of a NSPS) with impacts under the promulgated standard level of control. These impact analyses are based on the use of fixed-bed carbon adsorption/solvent recovery systems for control of VOC emissions from both existing and affected facilities. All existing facilities installed before October 1980 are assumed to be controlled at the 75 percent baseline level.

The projected impacts are calculated based on the expectation that 15 percent (85 percent overall control) of the total VOC solvent used at affected facilities will be emitted. Emissions are expected to increase to the 16 percent level (84 percent overall control) during only 1 or 2 months per year.

Compared to the baseline control level, the standard will further reduce VOC air pollutant emissions from typical affected facilities by 13 percent. The standard will reduce the industrywide VOC emissions by about 7,900 megagrams per year in the year 1985, the fifth year after the applicable date of the standard. This represents about five percent more reduction of industrywide emissions than with control at the baseline level. This projection is based on the expectation of 7 percent annual real growth rate in this industry.

Potential water pollution from a facility controlled under the standards is 13 percent greater than that from one controlled at the baseline level. Projected nationwide discharges for 1985 will increase by about 32 million liters above that for control at the baseline level. In the year 1985, dissolved organic solvents in the nationwide effluent will potentially amount to about 6 megagrams per year more than for control at the baseline level. This represents about a five percent incremental increase. Some treatment of this wastewater is necessary. One very effective demonstrated treatment method involves on-site hot air-stripping. The stripped solvent vapors are directed back to the carbon adsorber system for recovery. The resultant solvent-free water (less than 5 ppm) can be directly recycled for process use within the plant. This technique is effective because the solvents used exhibit very low miscibility with water. This inexpensive solvent removal system was included in cost analyses of the model plant carbon adsorption control systems. Two other treatment options are discharge to a conventional biological waste treatment system (e.g., activated sludge, trickle filter) and liquid-phase carbon adsorption. Air-stripping, biological treatment and liquid-phase carbon adsorption could successfully treat all wastewater generated from vapor-phase carbon adsorption control systems.

Implementation of the standard will increase the generation of solid waste because of the installation of additional recovery equipment. Spent carbon and carbon fines will increase as will the waste filters used to clean the solvent laden air upstream of the carbon bed. By 1985, however, the maximum amount of additional waste carbon generated because of the standard would be only about 85 Mg. Disposing of this small incremental amount of solid waste will pose no significant problem. The carbon may be sent back to the manufacturer for regeneration, or it could be incinerated, supplying an excellent source of fuel energy. Landfilling is also an appropriate method of disposal. Even if all of it were disposed of in landfills, it would amount to less than 2 tons per state during the entire 5-year period, truly an insignificant amount. Similarly, the incremental quantity of waste filters would also be very small.

The only significant source of noise is from the large SLA fans. However, these are normally installed in an enclosed housing, and should not affect the surrounding environment.

In the Administrator's opinion, the standard's environmental impacts as just described are reasonable.

The standard requires a direct energy consumption increase for the industry; however, the impact of solvent recovery control systems will decrease the nationwide demand for crude oil for solvent production. The direct energy consumption by a facility controlled under the standard is about 18 percent higher than if controlled at the baseline level. The direct annual energy consumption for a typical four-press plant will be increased by about the equivalent of 2,200 barrels of fuel oil. The industry's total direct energy consumption for the year 1985 will be about 40,200 barrels of fuel oil above that required for baseline control. This represents an energy consumption increase of about 9 percent more than with control of affected facilities at the baseline level.

The solvent recovery impact of the standard results in net national energy savings when the fuel energy value of the recovered solvent is considered. In the year 1985, industry's direct energy consumption will be favorably offset by a nationwide decrease in energy demand equivalent to about 21,800 barrels of fuel oil from that required for baseline control. The Administrator believes that the direct energy impact on the industry is reasonable, particularly in view of the net national energy savings that would result from decreased solvent demand.

The standard will increase industry's required capital investment by about two percent more than for control at the baseline level. The capital investment for a typical four-press plant will increase by about $650,000. Industry's cumulative five-year capital investments, through the year 1985, will increase by about $17 million. However, this incremental capital requirement is not large enough to reduce capital availability and, therefore, will not restrict industry growth.

Control system operating costs will increase under the standard; however, the high cost value of recovered solvent will enable solvent recovery systems to provide a net profit (negative annualized

costs) and positive return on investments. Control of a typical plant at baseline level would provide about $345,000 annualized net profit and 17 percent annual return on controls investment (ROI) because of the recovered solvent credit. Control at the standard level will decrease the annualized savings to about $271,000 and controls ROI to about ten percent annually. Thus, the standard will impose an incremental annual operating cost of about $74,000. In the year 1985, industry's incremental total annualized control costs with solvent recovery credit will be about $2.5 million. Despite these added costs, this industry's average pre-tax profit margin of eight percent at the baseline control level should not decrease below 7.8 percent under the standard. This very small profitability impact will not cause any significant price increases for publication gravure products. The Administrator, therefore, believes that the economic impacts of the standard are reasonable.

The environmental, energy and economic impacts are discussed in greater detail in "Publication Rotogravure Printing—Background Information for Proposed Standards" (EPA–450/3–80–031a). These impacts have not changed since proposal.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, an evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. The costs are provided for an economic analysis that reveals the affordability of controls in a study of the economic impact of controls on an industry.

Public Participation

Prior to proposal of this standard, interested parties were advised by public notice in the **Federal Register** (44 FR 65670, November 14, 1979) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the regulation recommended for proposal. This meeting was held on December 13, 1979. The meeting was open to the public and each attendant was given an opportunity to comment on the standard recommended for proposal. The standard was proposed and published in the **Federal Register** on October 28, 1980 (45 FR 71538). The preamble to the proposed standard discussed the availability of the BID, "Publication Rotogravure Printing—Background Information for Proposed Standards" (EPA–450/3–80–031a), which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standard, a public hearing was held on November 25, 1980, at Research Triangle Park, North Carolina. The hearing was open to the public and each person was given an opportunity to comment on the proposed standard. The public comment period was from October 28, 1980 to January 5, 1981.

Seven comment letters were received and one interested party testified at the public hearing concerning issues relative to the proposed standard of performance for publication rotogravure printing. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standard.

Significant Comments and Changes to the Proposed Standard

The proposed regulation was extensively revised for promulgation. The format of the standard and compliance provisions were changed from a volume to a mass basis. Continual monthly performance tests and all periodic reporting requirements were deleted. Recordkeeping requirements were reduced. Also, options for ink and solvent monitoring procedures were added. The title for the proposed reference test method was changed from 29 to 24A.

Comments on the proposed standard were received from industry, one Federal agency, one State air pollution control agency, and one trade association. No comments were received from environmental groups. A detailed discussion of these comments and responses can be found in the BID for the promulgated standard, which is referred to in the ADDRESSES section of this preamble. The summary of comments and responses in the BID serves as the basis for the revisions made to the regulation between proposal and promulgation. This preamble contains summaries of the Agency's responses to the major comments. More detailed discussion of the Agency's responses to these and to other comments is contained in the BID. The comments have been divided into the following areas: General, Emission Control Technology, Modification and Reconstruction, Economic Impact, Emission Monitoring, Test Methods, and Recordkeeping and Reporting.

General

Two commenters felt that the definition of VOC was not clear and asked if EPA had planned to publish a method of determining if an organic compound participated in atmospheric photochemical reactions. The definition of VOC, to which this comment referred, was promulgated at 45 FR 85415 on December 24, 1980 as part of another regulation after this regulation was proposed. The 40 CFR 60.2 was amended in July 1981 to include this definition. A method of determining photochemical reactivity is not part of the definition of VOC. However, EPA does determine photochemical reactivity of organic compounds and lists in the **Federal Register** those considered to be of negligible reactivity. EPA's latest policy, as of this date, was published on July 22, 1980 (45 FR 48941).

Emission Control Technology

One commenter referrred to an industry study reported in a trade newsletter. The study was conducted on paperboard rotogravure presses and the report implied the solvent vapor capture efficiency may not be as high as templated by EPA, especially for retrofitted presses. EPA noted, however, that the report of the study cited by the commenter acknowledged that the test methods used were not accurate. Paperboard presses are not subject to this standard, but the press and capture system are similar to publication rotogravure presses. During the development of this standard, EPA used accurate and rigorous test procedures in determining capture efficiency. Furthermore, EPA finds no reason, and the commenter did not identify any reason, for a retrofitted press to have a lower capture efficiency than a new press since both capture systems could consist of similarly designed add-on devices having the same capture efficiencies. No commenter offered specific process reasons that would

render control technology infeasible or exorbitantly costly. No changes were made in the standard as a result of this comment.

Modification and Reconstruction

During the development of this standard, prior to proposal, the information EPA obtained from the industry led to the conclusion that existing facilities would not likely become affected facilities under the provisions for modification and reconstruction (40 CFR 60.14 and 60.15). Rapidly improving press operation technology would make new printing presses and associated equipment significantly more desirable to maintain or improve a printer's competitive position.

EPA was subsequently told in a meeting requested by industry (docket number A-79-50/77/8-IV-E-19) that reconstruction and modification may occur due to the present high cost of capital. One commenter further stated that neither modified nor reconstructed presses should be subject to emission limits as stringent as totally new facilities.

EPA requested more information in order to assess the possibility that the standard may not be reasonable for modified or reconstructed facilities. Specifically, EPA attempted to conduct cost and economic analyses on expansion of existing carbon adsorption controls for retrofit model plant cases. Discussions with a carbon adsorber manfacturer and a trade association representative indicated that capital costs for a control system on a retrofitted facility are generally higher than for the same size new facility. This information does not suggest, however, that these costs would be unreasonable. No one could provide specific cost factors for retrofitted installations because the costs would be dependent upon site-specific situations. EPA must conclude that the effect of the standard on modified and reconstructed facilities is not significantly different from new facilities and that possible impacts would be reasonable. Since the provisions of 40 CFR 60.15 provide for case-by-case determinations of technical and economic feasibility, reconstructed sources are precluded from unreasonable impact. In the case of a modification, without any specific examples of circumstances under which unreasonable impact would result from compliance with the standard, EPA finds no basis at this time for establishing a separate standard or an exemption.

Economic Impact

One commenter noted that proper handling and disposal of spent carbon from the adsorber might increase the economic impact of the standard especially if spent carbon was considered a hazardous waste under the Resource Conservation and Recovery Act. In response to this comment, EPA pointed out that in the analysis of carbon adsorption systems undertaken by EPA prior to the development of the standard, it was assumed that facilities would use the existing, routine option of returning the waste carbon to the activated carbon supplier who would be equipped to handle the waste in an acceptable way. The economic impact analysis is correct as computed and no changes were made in the regulation as a result of this comment.

Emission Monitoring

Several commenters stated that the specific requirements for ink and solvent press flow meters, meter recalibrations, associated temperature monitoring, and waterborne ink systems made the regulation too detailed, complex, and inflexible. The Agency has made five major changes that simplify and add flexibility to the final regulation. First, the final regulation allows several options for measuring the amount of ink and solvent used at the press. Second, facilities are not subject to continual monthly performance tests. Third, in addition to the compliance options included in the proposed standards, the final regulation permits the owner or operator to show compliance on a plantwide basis, involving existing as well as affected facilities. Fourth, the monthly and all periodic reporting requirements have been deleted. Finally, the waterborne ink compliance provisions have been revised and combined with those for solvent-borne ink systems.

The specific requirements for individual press flow meters were deleted. As suggested by the commenters, alternatives to press flow meters as measuring devices have been provided. Ink, solvent, and water used at affected facilities may be measured by any accurate method the owner or operator chooses to use. Alternative measurement techniques include storage tank weighings or level measurements, delivery tank truck loading and unloading meters, tank truck weighings, and ink supplier shipment records.

Continual monthly performance test requirements were deleted. Compliance with the standard must be demonstrated during an initial performance test and additional performance tests as requested by the Administrator. Performance is measured over a 30 consecutive calendar day period for each test. The regulation allows seven compliance options for conducting the tests. If affected facilities are controlled by solvent recovery systems separate from existing facilities, but are installed to routinely share the same ink and solvent/handling system with existing facilities, then the ink, solvent, and water measurement procedures used during the tests must include a temporary method of accounting for segregated usage by that one affected facility or group of affected facilities. An overall emission percentage for the combined facilities as well as for only the affected facilities must be determined during the test period to provide a point of comparison for monthly records of performance. In this case, monthly emission percentages for the combined facilities can be compared to the overall average for the existing and affected facilities' performance determined during the performance test.

If affected and existing facilities are controlled by the same solvent recovery system, the owner or operator can choose between two optional test procedures to show compliance of the affected facilities. The first test option requires a separate 30-day emission test on the existing facilities. Then a 30-day performance test is conducted on the combined existing and affected facilities to determine the affected facilities' emission percentage. Like the previous case, the ink, solvent, and water measurement procedures used during the performance test must include a temporary method of accounting for segregated usage by the tested facilities. The second test option is to show compliance of the combined affected and existing facilities. No separate emission tests for existing facilities are required for this option. Also, no temporary segregated liquid measurement procedures are required for this second option.

In response to the commenters' request for alternative compliance provisions, the Agency has added a final plantwide test option. This option allows the owner or operator to demonstrate compliance by showing that the total VOC discharged from all affected and existing facilities in the plant is equal to or less than 18 percent of the toal mass of VOC solvent and water used at those facilities during the performance test. This option gives industry the flexibility requested in the comments by removing the requirement that the owner or operator measure raw ink usage at each affected facility. No

separate emission tests on existing facilities and no temporary segregated liquid measurement procedures for affected facilities are required for tests under this option.

Because this last option permits a showing of plantwide compliance, an owner or operator choosing this option would be required to show that the average control among all plant facilities—affected and existing—is equal to or better than the NSPS level of control. In the Agency's judgment, under the circumstances presented here this assures that the affected facilities within the plants will achieve the degree of control reflecting application of the best demonstrated system of continuous emission reduction. As a result, the plantwide compliance option will provide rotogravure plant owners the benefit of measurement flexibility without any resulting loss in emission reduction.

For all performance tests, the final regulation requires at least weekly accounting of liquid usages and recovered solvent. Temperature monitoring was also reduced from daily to at least weekly for performance tests. This is a reduction from the daily meter and temperature readings required by the proposed regulation. However, if press flow meters are not used, records for each liquid material shipment may require more frequent accounting. In cases where ink, solvent, and water usages are measured by volume, liquid densities are required to convert to a mass basis material balance. Since density of a liquid varies with temperature, it is necessary to monitor the temperature while the quantity of liquid used or recovered is measured. For the solvents used in this industry, the potential density error in determination of compliance could be 2 to 3.5 percent or more, depending on ambient weather and equipment operating conditions.

An option was added to the final regulation to allow owners or operators using only solvent-borne inks to choose to show compliance by a temperature/density-corrected solvent volume balance instead of converting to a mass balance. This option may be desirable where all ink and solvents used are measured by volume. In the unique case where all solvent used and recovered are measured at the same temperature, the direct volume calculated emission percentage would be identical to a mass balance.

After performance tests are completed, only monthly monitoring for proper operation and maintenance of the control system is required. Monthly totals of solvent and water usage and recovered solvent are used to document emission percentages of affected facilities that have liquid monitoring systems segregated from existing facilities. However, temperature measurements are not required for monthly monitoring. The liquid densities determined in the latest performance test are assumed to remain constant and are used in the emission percentage estimates. For affected facilities which share the same ink and solvent storage/handling system with existing facilities, segregated liquid accounting procedures for affected facilities are not required for monthly monitoring. Monthly emission percentages for the combined facilities can be documented and compared to the overall average for the existing and affected facilities' emission percentage determined during the latest performance test.

The monthly monitoring requirement is a major change from the proposed regulation requirement of continual monthly performance tests. The Administrator feels that the burden of continual performance tests is unnecessary. This industry's economic incentive to recover solvent and the possibility that the Administrator could impose a performance test are sufficient to ensure that this industry will operate the best demonstrated control system effectively.

The fourth major change, deletion of monthly reporting requirements is discussed below in the Reporting and Recordkeeping Section.

The final major change responded to comments on emission monitoring with waterborne ink systems. Commenters noted that the waterborne ink compliance provisions were too restrictive because addition of VOC at the press was prohibited and because the VOC-to-solids ratio basis would severely restrict the allowable VOC content of inks with a low solids content.

It was not EPA's intent to restrict the use of waterborne inks. As a result of these comments, the proposed standard was revised to allow the addition of VOC at the press. The waterborne ink standard was changed from a volume to a VOC weight percentage basis. The promulgated standard requires that the VOC weight content be no more than 16 percent of the total volatile portion of mixed waterborne inks, as applied. Use of this approach requires measurement of water and VOC added at the press.

Another commenter pointed out that the proposed standards did not address the approach of using a combination of waterborne and solvent-borne inks on different printing units of the same press. This comment stressed that dryer exhausts from waterborne units should be vented to the atmosphere instead of to the carbon adsorption system. If not, water vapor would affect the carbon's activity and the water miscible organics would be lost through the recovery decanter anyway.

The final standard includes compliance provisions that allow the combined use of low VOC waterborne and solvent-borne inks. The provisions also allow use of higher VOC waterborne inks, provided that the capture and control of solvent-borne VOC would be correspondingly increased to comply with the 16 percent emission limit for the entire press. EPA agrees that dryer exhaust and fugitive emissions from waterborne units should not be vented through carbon adsorbers and may be vented to the atmosphere provided the entire press complies with the 16 percent emission limit.

Test Methods

One commenter urged EPA to give printers the option of determining solvent-borne ink VOC content by using alternative analytical methods. Methods such as gas chromatography (GC) and mass spectrometry (MS) were suggested.

The regulation was not changed as this comment requested. At the present time, EPA has no reference method or specific procedures for GC or MS total VOC content analysis of solvent-borne printing inks. The regulation specifies Reference Method 24A (title number changed from proposed Reference Method 29) as the only acceptable analytical method. It is less expensive and less complicated than GC or MS, and it is more reliable for determination of total VOC content. However, the General Provisions for Standards of Performance for New Stationary Sources (40 CFR 60.8(b)) allow owners or operators of affected facilities to petition the Administrator for permission to use an alternative procedure for determining VOC content.

Recordkeeping and Reporting

The major comment on recordkeeping was that the requirements for daily temperature monitoring, daily meter readings, and monthly solvent base temperature calculations were excessive and unnecessary. As discussed above, the requirement for monthly compliance tests was deleted. The proposed recordkeeping requirements of ink and solvent usage and temperature monitoring have been reduced from daily to at least weekly during a performance test. All requirements for temperature monitoring during the months following the performance test

were deleted. In addition, only monthly records of the amount of solvent and water used, solvent recovered, and the estimated emission percentage are required. The calculation of solvent base temperature was deleted because it is not necessary when the emission limit standard changed from a volume to a mass basis. The required records will enable the company to be aware of the quality of the operation of the control system and allow enforcement personnel to check for proper operation and maintenance.

The major comment on reporting stated that the time limit of 10 days for submitting non-compliance reports was too short. Monthly non-compliance reports and all periodic reporting requirements have been deleted from the regulation. There are only two types of reports required: notifications as facilities become subject to the standard and a report of performance test results.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. On judicial review, the record will consist of all materials in the docket (including the statement of basis and purpose of the proposed and promulgated standards), except for certain intra-agency review materials [Section 307(d)(7)(A)].

Miscellaneous

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well publicized national forum to reach a decision on a pollution emission level that allows for a dynamic enonomy and a healthful environment.

The effective date of this regulation is November 8, 1982. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal; in this case October 28, 1980.

As prescribed by Section 111, the promulgation of this standard was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of this promulgated standard was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in this regulation will be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to insure that cost was carefully considered in determining BDT. The economic impact assessment is included in the background information document for the proposed standards.

The Paperwork Reduction Act of 1980 (PL # 96-511) requires clearance from the Office of Management and Budget (OMB) of certain public reporting/recordkeeping requirements before certain information requests can be made of the public. The reporting/recordkeeping requirements associated with this standard have been approved by OMB, and have been assigned OMB control number 2000-0462.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because it would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be major. In the fifth year after the standards would go into effect, the industry-wide incremental annualized control costs with solvent recovery credit will be about $2.5 million. This is much less than the $100 million established as first criterion for a major regulation the Order. No measureable price increase for gravure products would occur as a result of this standard. O course, this would not be considere "major increase in costs or prices" specified as the second criterion in Order. The economic analysis of the proposed standard's effects on the industry did not indicate any signifi adverse effects on competition, investment, productivity, employmer innovation, or the ability of U.S. firm compete with foreign firms (the third criterion in the Order).

This regulation was submitted to Office of Management and Budget f review as required by Executive Or 12291. Any comments from OMB to and any EPA response to those comments are available for public inspection in the docket referenced the address section of this preamble

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric pow plants, Glass and glass products, Gr Incorporation by reference, Intergovernmental relations, Iron, Le Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sew disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc.

Dated: October 20, 1982.

Anne M. Gorsuch,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended as follo

1. A new Subpart QQ is added as follows:

Subpart QQ—Standards of Performanc the Graphic Arts Industry: Publication Rotogravure Printing

Sec.

60.430 Applicability and designation of affected facility.
60.431 Definitions and notations.
60.432 Standard for volatile organic compounds.
60.433 Performance test and compliance provisions.
60.434 Monitoring of operations and recordkeeping.
60.435 Test methods and procedures.

Authority: Sec. 111 and 301(a) of the Cl Air Act, as amended, (42 U.S.C. 7411, 760 (a)), and additional authority as noted be

Subpart QQ—Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing

§ 60.430 Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which the provisions of this subpart apply is each publication rotogravure printing press.

(b) The provisions of this subpart do not apply to proof presses.

(c) Any facility under paragraph (a) of this section that commences construction, modification, or reconstruction after October 28, 1980 is subject to the requirements of this subpart.

§ 60.431 Definitions and notations.

(a) All terms used in this subpart that are not defined below have the meaning given to them in the Act and in Subpart A of this part.

"Automatic temperature compensator" means a device that continuously senses the temperature of fluid flowing through a metering device and automatically adjusts the registration of the measured volume to the corrected equivalent volume at a base temperature.

"Base temperature" means an arbitrary reference temperature for determining liquid densities or adjusting the measured volume of a liquid quantity.

"Density" means the mass of a unit volume of liquid, expressed as grams per cubic centimeter, kilograms per liter, or pounds per gallon, at a specified temperature.

"Gravure cylinder" means a printing cylinder with an intaglio image consisting of minute cells or indentations specially engraved or etched into the cylinder's surface to hold ink when continuously revolved through a fountain of ink.

"Performance averaging period" means 30 calendar days, one calendar month, or four consecutive weeks as specified in sections of this subpart.

"Proof press" means any device used only to check the quality of the image formation of newly engraved or etched gravure cylinders and prints only non-saleable items.

"Publication rotogravure printing press" means any number of rotogravure printing units capable of printing simultaneously on the same continuous web or substrate and includes any associated device for continuously cutting and folding the printed web, where the following saleable paper products are printed:

- Catalogues, including mail order and premium,
- Direct mail advertisements, including circulars, letters, pamphlets, cards, and printed envelopes,
- Display advertisements, including general posters, outdoor advertisements, car cards, window posters; counter and floor displays; point-of-purchase, and other printed display material,
- Magazines,
- Miscellaneous advertisements, including brochures, pamphlets, catalogue sheets, circular folders, announcements, package inserts, book jackets, market circulars, magazine inserts, and shopping news,
- Newspapers, magazine and comic supplements for newspapers, and preprinted newspaper inserts, including hi-fi and spectacolor rolls and sections,
- Periodicals, and
- Telephone and other directories, including business reference services.

"Raw ink" means all purchased ink.

"Related coatings" means all non-ink purchased liquids and liquid-solid mixtures containing VOC solvent, usually referred to as extenders or varnishes, that are used at publication rotogravure printing presses.

"Rotogravure printing unit" means any device designed to print one color ink on one side of a continuous web or substrate using a gravure cylinder.

"Solvent-borne ink systems" means ink and related coating mixtures whose volatile portion consists essentially of VOC solvent with not more than five weight percent water, as applied to the gravure cylinder.

"Solvent recovery system" means an air pollution control system by which VOC solvent vapors in air or other gases are captured and directed through a condenser(s) or a vessel(s) containing beds of activated carbon or other adsorbents. For the condensation method, the solvent is recovered directly from the condenser. For the adsorption method, the vapors are adsorbed, then desorbed by steam or other media, and finally condensed and recovered.

"VOC" means volatile organic compound.

"VOC solvent" means an organic liquid or liquid mixture consisting of VOC components.

"Waterborne ink systems" means ink and related coating mixtures whose volatile portion consists of a mixture of VOC solvent and more than five weight percent water, as applied to the gravure cylinder.

(b) Symbols used in this subpart are defined as follows:

D_B = the density at the base temperature of VOC solvent used or recovered during one performance averaging period.

D_{ci} = the density of each color of raw ink and each related coating (i) used at the subject facility (or facilities), at the coating temperature when the volume of coating used is measured.

D_{di} = the density of each VOC solvent (i) added to the ink for dilution at the subject facility (or facilities), at the solvent temperature when the volume of solvent used is measured.

D_{ei} = the density of each VOC solvent (i) used as a cleaning agent at the subject facility (or facilities), at the solvent temperature when the volume of cleaning solvent used is measured.

D_{hi} = the density of each quantity of water (i) added at the subject facility (or facilities) for dilution of waterborne ink systems at the water temperature when the volume of dilution water used is measured.

D_{mi} = the density of each quantity of VOC solvent and miscellaneous solvent-borne waste inks and waste VOC solvents (i) recovered from the subject facility (or facilities), at the solvent temperature when the volume of solvent recovered is measured.

D_{oi} = the density of the VOC solvent contained in each raw ink and related coating (i) used at the subject facility (or facilities), at the coating temperature when the volume of coating used is measured.

D_w = the density of the water contained in each waterborne raw ink and related coating (i) used at the subject facility (or facilities), at the coating temperature when the volume of coating used is measured.

L_{ci} = the measured liquid volume of each color of raw ink and each related coating (i) used at the facility of a corresponding VOC content, V_{oi} or W_{oi}, with a VOC density, D_{oi}, and a coating density, D_{ci}.

L_{di} = the measured liquid volume of each VOC solvent (i) with corresponding density, D_{di}, added to dilute the ink used at

M_{ci} = the mass, determined by direct weighing, of each color of raw ink and each related coating (i) used at the subject facility (or facilities).

M_d = the mass, determined by direct weighing, of VOC solvent added to dilute the ink used at the subject facility (or facilities) during one performance averaging period.

M_e = the mass, determined by direct weighing, of VOC solvent used as a cleaning agent at the subject facility (or facilities) during one performance averaging period.

M_h = the mass, determined by direct weighing, of water added for dilution with waterborne ink systems used at the subject facility (or facilities) during one performance averaging period.

M_m = the mass, determined by direct weighing, of VOC solvent and miscellaneous solvent-borne waste inks and waste VOC solvents recovered from the subject facility (or facilities) during one performance averaging period.

M_o = the total mass of VOC solvent contained in the raw inks and related coatings used

at the subject facility (or facilities) during one performance averaging period.

M_r = the total mass of VOC solvent recovered from the subject facility (or facilities) during one performance averaging period.

M_t = the total mass of VOC solvent used at the subject facility (or facilities) during one performance averaging period.

M_w = the total mass of water used with waterborne ink systems at the subject facility (or facilities) during one performance averaging period.

M_{ww} = the total mass of water contained in the waterborne raw inks and related coatings used at the subject facility (or facilities) during one performance averaging period.

P = the average VOC emission percentage for the subject facility (or facilities) for one performance averaging period.

V_{oi} = the liquid VOC content, expressed as a volume fraction of VOC volume per total volume of coating, of each color of raw ink and related coating (i) used at the subject facility (or facilities).

V_{wi} = the water content, expressed as a volume fraction of water volume per total volume of coating, of each color of waterborne raw ink and related coating (i) used at the subject facility (or facilities).

W_{oi} = the VOC content, expressed as a weight fraction of mass of VOC per total mass of coating, of each color of raw ink and related coating (i) used at the subject facility (or facilities).

W_{wi} = the water content, expressed as a weight fraction of mass of water per total mass of coating, of each color of waterborne raw ink and related coating (i) used at the subject facility (or facilities).

(c) The following subscripts are used in this subpart with the above symbols to denote the applicable facility:

a = affected facility.

b = both affected and existing facilities controlled in common by the same air pollution control equipment.

e = existing facility.

f = all affected and existing facilities located within the same plant boundary.

§ 60.432 Standard for volatile organic compounds.

During the period of the performance test required to be conducted by § 60.8 and after the date required for completion of the test, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility VOC equal to more than 16 percent of the total mass of VOC solvent and water used at that facility during any one performance averaging period. The water used includes only that water contained in the waterborne raw inks and related coatings and the water added for dilution with waterborne ink systems.

§ 60.433 Performance test and compliance provisions.

(a) The owner or operator of any affected facility (or facilities) shall conduct performance tests in accordance with § 60.8, under the following conditions:

(1) The performance averaging period for each test is 30 consecutive calendar days and not an average of three separate runs as prescribed under § 60.8(f).

(2) Except as provided under paragraphs (f) and (g) of this section, if affected facilities routinely share the same raw ink storage/handling system with existing facilities, then temporary measurement procedures for segregating the raw inks, related coatings, VOC solvent, and water used at the affected facilities must be employed during the test. For this case, an overall emission percentage for the combined facilities as well as for only the affected facilities must be calculated during the test.

(3) For the purpose of measuring bulk storage tank quantities of each color of raw ink and each related coating used, the owner or operator of any affected facility shall install, calibrate, maintain, and continuously operate during the test one or more—

(i) Non-resettable totalizer metering device(s) for indicating the cumulative liquid volumes used at each affected facility; or

(ii) Segregated storage tanks for each affected facility to allow determination of the liquid quantities used by measuring devices other than the press meters required under item (i) of this article; or

(iii) Storage tanks to serve more than one facility with the liquid quantities used determined by measuring devices other than press meters, if facilities are combined as decribed under paragraph (d), (f), or (g) of this section.

(4) The owner or operator may choose to install an automatic temperature compensator with any liquid metering device used to measure the raw inks, related coatings, water, or VOC solvent used, or VOC solvent recovered.

(5) Records of the measured amounts used at the affected facility and the liquid temperature at which the amounts were measured are maintained for each shipment of all purchased material or on at least a weekly basis for—

(i) The raw inks and related coatings used;

(ii) The VOC and water content of each raw ink and related coating used as determined according to § 60.435.

(iii) The VOC solvent and water added to the inks used;

(iv) The VOC solvent used as a cleaning agent; and

(v) The VOC solvent recovered.

(6) The density variations with temperature of the raw inks, related coatings, VOC solvents used, and VOC solvent recovered are determined by the methods stipulated in § 60.435(d).

(7) The calculated emission percentage may be reported as rounded-off to the nearest whole number.

(8) Printing press startups and shutdowns are not included in the exemption provisions under § 60.8(c). Frequent periods of press startups and shutdowns are normal operations and constitute representative conditions for the purpose of a performance test.

(b) If an affected facility uses waterborne ink systems or a combination of waterborne and solvent-borne ink systems with a solvent recovery system, compliance is determined by the following procedures, except as provided in paragraphs (d), (e), (f), and (g) of this section:

(1) The mass of VOC in the solvent-borne and waterborne raw inks and related coatings used is determined by the following equation:

$$(M_o)_a = \sum_{i=1}^{k} (M_{ci})_a (W_{oi})_a + \sum_{i=1}^{m} (L_{ci})_a (D_{ci})_a (W_{oi})_a + \sum_{i=1}^{n} (L_{ci})_a (V_{oi})_a (D_{oi})_a$$

where:

k is the total number of raw inks and related coatings measured as used in direct mass quantities with different amounts of VOC content.

m is the total number of raw inks and related coatings measured as used by volume with different amounts of VOC content or different densities.

n is the total number of raw inks and related coatings measured as used by volume with different amounts of VOC content or different VOC solvent densities.

(2) The total mass of VOC used is determined by the following equation:

$$(M_t)_a = (M_o)_a + \sum_{i=1}^{m} (L_{ci})_a (D_{ci})_a + (M_d)_a + \sum_{i=1}^{n} (L_{ci})_a (D_{ci})_a + (M_c)_a$$

Where "m" and "n" are the respective total numbers of VOC dilution and cleaning solvents measured as used by volume with different densities.

(3) The mass of water in the waterborne raw inks and related coatings used is determined by the following equation:

$$(M_w)_a = \sum_{i=1}^{k} (M_{ci})_a (W_{wi})_a + \sum_{i=1}^{m} (L_{ci})_a (D_{ci})_a (W_{wi})_a + \sum_{i=1}^{n} (L_{ci})_a (V_{wi})_a (D_{wi})_a$$

k is the total number of raw inks and related coatings measured as used in direct mass quantities with different amounts of water content.

m is the total number of raw inks and related coatings measured as used by volume with different amounts of water content or different densities.

n is the total number of raw inks and related coatings measured as used by volume with different amounts of water content or different water densities.

(4) The total mass of water used is determined by the following equation:

$$(M_w)_a = (M_w)_a + (M_h)_a + \sum_{i=1}^{m} (L_{mi})_a (D_{mi})_a$$

where "m" is the total number of water dilution additions measured as used by volume with different densities.

(5) The total mass of VOC solvent recovered is determined by the following equation:

$$(M_r)_a = (M_{ro})_a + \sum_{i=1}^{k} (L_{mi})_a (D_{mi})_a$$

where "k" if the total number of VOC solvents, miscellaneous solvent-borne waste inks, and waste VOC solvents measured as recovered by volume with different densities.

(6) The average VOC emission percentage for the affected facility is determined by the following equation:

$$P_a = \left[\frac{(M_t)_a - (M_r)_a}{(M_t)_a + (M_w)_a}\right] \times 100$$

(c) If an affected facility controlled by a solvent recovery system uses only solvent-borne ink systems, the owner or operator may choose to determine compliance on a direct mass or a density-corrected liquid volume basis. Except as provided in paragraphs (d), (e), (f), and (g) of this section, compliance is determined as follows:

(1) On a direct mass basis, compliance is determined according to paragraph (b) of this section, except that the water term, M_w, does not apply.

(2) On a density-corrected liquid volume basis, compliance is determined by the following procedures:

(i) A base temperature corresponding to that for the largest individual amount of VOC solvent used or recovered from the affected facility, or other reference temperature, is chosen by the owner or operator.

(ii) The corrected liquid volume of VOC in the raw inks and related coatings used is determined by the following equation:

$$(L_w)_a = \sum_{i=1}^{k} \frac{(M_{ci})_a (W_{oi})_a}{D_s} + \sum_{i=1}^{m} \frac{(L_{ci})_a (D_{ci})_a (W_{oi})_a}{D_s} + \sum_{i=1}^{n} \frac{(L_{ci})_a (V_{oi})_a (D_{oi})_a}{D_s}$$

where,

k is the total number of raw inks and related coatings measured as used in direct mass quantities with different amounts of VOC content.

m is the total number of raw inks and related coatings measured as used by volume with different amounts of VOC content or different densities.

n is the total number of raw inks and related coatings measured as used by volume with different amounts of VOC content or different VOC solvent densities.

(iii) The total corrected liquid volume of VOC used is determined by the following equation:

$$(L_t)_a = (L_w)_a + \sum_{i=1}^{m} \frac{(L_{ci})_a (D_{ci})_a}{D_s} + \frac{(M_c)_a}{D_s} + \sum_{i=1}^{n} \frac{(L_{ci})_a (D_{ci})_a}{D_s} + \frac{(M_z)_a}{D_s}$$

where "m" and "n" are the respective total numbers of VOC dilution and cleaning solvents measured as used by volume with different densities.

(iv) The total corrected liquid volume of VOC solvent recovered is determined by the following equation:

$$(L_r)_a = \frac{(M_{ro})_a}{D_s} + \sum_{i=1}^{k} \frac{(L_{mi})_a (D_{mi})_a}{D_s}$$

where "k" is the total number of VOC solvents, miscellaneous solvent-borne waste inks, and waste VOC solvents measured as recovered by volume with different densities.

(v) The average VOC emission percentage for the affected facility is determined by the following equation:

$$P_a = \left[\frac{(L_t)_a - (L_r)_a}{(L_t)_a}\right] \times 100$$

(d) If two or more affected facilities are controlled by the same solvent recovery system, compliance is determined by the procedures specified in paragraph (b) or (c) of this section, whichever applies, except that $(L_t)_a$ and $(L_r)_a$, $(M_t)_a$, $(M_r)_a$, and $(M_w)_a$, are the collective amounts of VOC solvent and water corresponding to all the affected facilities controlled by that solvent recovery system. The average VOC emission percentage for each of the affected facilities controlled by that same solvent recovery system is assumed to be equal.

(e) Except as provided under paragraph (f) of this section, if an existing facility (or facilities) and an affected facility (or facilities) are controlled in common by the same solvent recovery system, the owner or operator shall determine compliance by conducting a separate emission test on the existing facility (or facilities) and then conducting a performance test on the combined facilities as follows:

(1) Before the initial startup of the affected facility (or facilities) and at any other time as requested by the Administrator, the owner or operator shall conduct emission test(s) on the existing facility (or facilities) controlled by the subject solvent recovery system. The solvent recovery system must handle VOC emissions from only the

subject existing facility (or facilities), not from affected facilities, during the emission test.

(2) During the emission test, the affected facilities are subject to the standard stated in § 60.432.

(3) The emission test is conducted over a 30 consecutive calendar day averaging period according to the conditions stipulated in § 60.433(a)(1) through (a)(5), except that the conditions pertain to only existing facilities instead of affected facilities.

(4) The owner or operator of the existing facility (or facilities) shall provide the Administrator at least 30 days prior notice of the emission test to afford the Administrator the opportunity to have an observer present.

(5) The emission percentage for the existing facility (or facilities) during the emission test is determined by one of the following procedures:

(i) If the existing facility (or facilities) uses a combination of waterborne and solvent-borne ink systems, the average VOC emission percentage must be determined on a direct mass basis according to paragraph (b) or (d) of this section, whichever applies, with the following equation:

$$P_e = \left[\frac{(M_t)_e - (M_r)_e}{(M_t)_e + (M_s)_e}\right] \times 100$$

where the water and VOC solvent amounts pertain to only existing facilities.

(ii) If the existing facility (or facilities) uses only solvent-borne ink systems, the owner or operator may choose to determine the emission percentage either on a direct mass basis or a density-corrected liquid volume basis according to paragraph (c) or (d) of this section, whichever applies. On a direct mass basis, the average VOC emission percentage is determined by the equation presented in article (i) of this paragraph. On a density-corrected liquid volume basis, the average VOC emission percentage is determined by the following equation:

$$P_e = \left[\frac{(L_t)_e - (L_r)_e}{(L_t)_e}\right] \times 100$$

where the VOC solvent amounts pertain to only existing facilities.

(6) The owner or operator of the existing facility (or facilities) shall furnish the Administrator a written report of the results of the emission test.

(7) After completion of the separate emission test on the existing facility (or facilities), the owner or operator shall conduct performance test(s) on the combined facilities with the solvent recovery system handling VOC emissions from both the existing and affected facilities.

(8) During performance test(s), the emission percentage for the existing facility (or facilities), P_e, is assumed to be equal to that determined in the latest emission test. The administrator may request additional emission tests if any physical or operational changes occur to any of the subject existing facilities.

(9) The emission percentage for the affected facility (or facilities) during performance test(s) with both existing and affected facilities connected to the solvent recovery system is determined by one of the following procedures:

(i) If any of the combined facilities uses both waterborne and solvent-borne ink systems, the average VOC emission percentage must be determined on a direct mass basis according to paragraph (b) or (d) of this section, whichever applies, with the following equation:

$$P_a = \left\{\frac{(M_t)_b - (M_r)_b - \left(\frac{P_e}{100}\right)[(M_t)_e + (M_s)_e]}{(M_t)_a + (M_s)_a}\right\} \times 100$$

where $(M_t)_b$ and $(M_r)_b$ are the collective VOC solvent amounts pertaining to all the combined facilities.

(ii) If all of the combined facilities use only solvent-borne ink systems, the owner or operator may choose to determine performance of the affected facility (or facilities) either on a direct mass basis or a density-corrected liquid volume basis according to paragraph (c) or (d) of this section, whichever applies. On a direct mass basis, the average VOC emission percentage is determined by the equation presented in article (i) of this paragraph. On a density-corrected liquid volume basis, the average VOC emission percentage is determined by the following equation:

$$P_a = \left\{\frac{(L_t)_b - (L_r)_b - (L_t)_e\left(\frac{P_e}{100}\right)}{(L_t)_a}\right\} \times 100$$

where $(L_t)_b$ and $(L_r)_b$ are the collective VOC solvent amounts pertaining to all the combined facilities.

(f) The owner or operator may choose to show compliance of the combined performance of existing and affected facilities controlled in common by the same solvent recovery system. A separate emission test for existing facilities is not required for this option. The combined performance is determined by one of the following procedures:

(1) If any of the combined facilities uses both waterborne and solvent-borne ink systems, the combined average VOC emission percentage must be determined on a direct mass basis according to paragraph (b) or (d) of this section, whichever applies, with the following equation:

$$P_b = \left[\frac{(M_t)_b - (M_r)_b}{(M_t)_b + (M_s)_b}\right] \times 100$$

(2) If all of the combined facilities use only solvent-borne ink systems, the owner or operator may choose to determine performance either on a direct mass basis or a density-corrected liquid volume basis according to paragraph (c) or (d) of this section, whichever applies. On a direct mass basis, the average VOC emission percentage is determined by the equation presented in article (i) of this paragraph. On a density-corrected liquid volume basis, the average VOC emission percentage is determined by the following equation:

$$P_b = \left[\frac{(L_t)_b - (L_r)_b}{(L_t)_b}\right] \times 100$$

(g) If all existing and affected facilities located within the same plant boundary use waterborne ink systems or solvent-borne ink systems with solvent recovery systems, the owner or operator may choose to show compliance on a plantwide basis for all the existing and affected facilities together. No separate emission tests on existing facilities and no temporary segregated liquid measurement procedures for affected facilities are required for this option. The plantwide performance is determined by one of the following procedures:

(1) If any of the facilities use waterborne ink systems, the total plant average VOC emission percentage must be determined on a direct mass basis according to paragraph (b) of this section with the following equation:

$$P_r = \left[\frac{(M_t)_f - (M_r)_a - (M_r)_s - (M_r)_b}{(M_t)_f + (M_w)_f}\right] \times 100$$

Where $(M_t)_f$ and $(M_w)_f$ are the collective VOC solvent and water amounts used at all the subject plant facilities during the performance test.

(2) If all of the plant facilities use only solvent-borne ink systems, the owner or operator may choose to determine performance either on a direct mass basis or a density-corrected liquid volume basis according to paragraph (c) of this section. On a direct mass basis, the total plant average VOC emission percentage is determined by the equation presented in article (i) of this paragraph. On a density-corrected liquid volume basis, the total plant average VOC emission percentage is determined by the following equation:

$$P_r = \left[\frac{(L_t)_f - (L_r)_a - (L_r)_c - (L_r)_b}{(L_t)_f}\right] \times 100$$

Where $(L_t)_f$ is the collective VOC solvent amount used at all the subject plant facilities during the performance test.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.434 Monitoring of operations and recordkeeping.

(a) After completion of the performance test required under § 60.8, the owner or operator of any affected facility using waterborne ink systems or solvent-borne ink systems with solvent recovery systems shall record the amount of solvent and water used, solvent recovered, and estimated emission percentage for each performance averaging period and shall maintain these records for 2 years. The emission percentage is estimated as follows:

(1) The performance averaging period for monitoring of proper operation and maintenance is a calendar month or 4 consecutive weeks, at the option of the owner or operator.

(2) If affected facilities share the same raw ink storage/handling system with existing facilities, solvent and water used, solvent recovered, and emission percentages for the combined facilities may be documented. Separate emission percentages for only the affected facilities are not required in this case. The combined emission percentage is compared to the overall average for the existing and affected facilities' emission percentage determined during the most recent performance test.

(3) Except as provided in article (4) of this paragraph, temperatures and liquid densities determined during the most recent performance test are used to calculate corrected volumes and mass quantities.

(4) The owner or operator may choose to measure temperatures for determination of actual liquid densities during each performance averaging period. A different base temperature may be used for each performance averaging period if desired by the owner or operator.

(5) The emission percentage is calculated according to the procedures under § 60.433(b) through (g), whichever applies, or by a comparable calculation which compares the total solvent recovered to the total solvent used at the affected facility.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.435 Test methods and procedures.

(a) The owner or operator of any affected facility using solvent-borne ink systems shall determine the VOC content of the raw inks and related coatings used at the affected facility by—

(1) Analysis using Reference Method 24A of routine weekly samples of raw ink and related coatings in each respective storage tank; or

(2) Analysis using Reference Method 24A of samples of each shipment of all purchased raw inks and related coatings; or

(3) Determination of the VOC content from the formulation data supplied by the ink manufacturer with each shipment of raw inks and related coatings used.

(b) The owner or operator of any affected facility using solvent-borne ink systems shall use the results of verification analyses by Reference Method 24A to determine compliance when discrepancies with ink manufacturers' formulation data occur.

(c) The owner or operator of any affected facility using waterborne ink systems shall determine the VOC and water content of raw inks and related coatings used at the affected facility by—

(1) Determination of the VOC and water content from the formulation data supplied by the ink manufacturer with each shipment of purchased raw inks and related coatings used; or

(2) Analysis of samples of each shipment of purchased raw inks and related coatings using a test method approved by the Administrator in accordance with § 60.8(b).

(d) The owner or operator of any affected facility shall determine the density of raw inks, related coatings, and VOC solvents by—

(1) Making a total of three determinations for each liquid sample at specified temperatures using the procedure outlined in ASTM D 1475–60 (Reapproved 1980), which is incorporated by reference. It is available from the American Society of Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103. It is also available for inspection at the Office of the Federal Register, Room 8401, 1100 L Street, N.W., Washington, D.C. This incorporation by reference was approved by the Director of the Federal Register on November 8, 1982. This material is incorporated as it exists on the date of approval and a notice of any change in these materials will be published in the **Federal Register**. The temperature and density is recorded as the arithmetic average of the three determinations; or

(2) Using literature values, at specified temperatures, acceptable to the Administrator.

(e) If compliance is determined according to § 60.433(e), (f), or (g), the existing as well as affected facilities are subject to the requirements of paragraphs (a) through (d) of this section.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

2. Method 24A is added to Appendix A as follows:

Appendix A—Reference Methods

* * * * *

Method 24A—Determination of Volatile Matter Content and Density of Printing Inks and Related Coatings

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the determination of the volatile organic compound (VOC) content and density of solvent-borne (solvent reducible) printing inks or related coatings.

1.2 Principle. Separate procedures are used to determine the VOC weight fraction and density of the coating and the density of the solvent in the coating. The VOC weight fraction is determined by measuring the weight loss of a known sample quantity which has been heated for a specified length of time at a specified temperature. The density of both the coating and solvent are measured by a standard procedure. From this information, the VOC volume fraction is calculated.

2. *Procedure.*

2.1 Weight Fraction VOC.

2.1.1 Apparatus.

2.1.1.1 Weighing Dishes. Aluminum foil, 58 mm in diameter by 18 mm high, with a flat bottom. There must be at least three weighing dishes per sample.

2.1.1.2 Disposable syringe, 5 ml.

2.1.1.3 Analytical Balance. To measure to within 0.1 mg.

2.1.1.4 Oven. Vacuum oven capable of maintaining a temperature of 120±2°C and an absolute pressure of 510 ±51 mm Hg for 4 hours. Alternatively, a forced draft oven capable of maintaining a temperature of 120 ±2°C for 24 hours.

2.1.1.5 Analysis. Shake or mix the sample thoroughly to assure that all the solids are completely suspended. Label and weigh to the nearest 0.1 mg a weighing dish and record this weight (M_{ti}).

Using a 5-ml syringe without a needle remove a sample of the coating. Weigh the syringe and sample to the nearest 0.1 mg and record this weight (M_{cv1}). Transfer 1 to 3 g of the sample to the tared weighing dish. Reweigh the syringe and sample to the nearest 0.1 mg and record this weight (M_{cv2}). Heat the weighing dish and sample in a vacuum oven at an absolute pressure of 510 ±51 mm Hg and a temperature of 120 ±2°C for 4 hours. Alternatively, heat the weighing dish and sample in a forced draft oven at a temperature of 120 ±2°C for 24 hours. After the weighing dish has cooled, reweigh it to the nearest 0.1 mg and record the weight (M_{ti2}). Repeat this procedure for a total of three determinations for each sample.

2.2 Coating Density. Determine the density of the ink or related coating according to the procedure outlined in ASTM D 1475–60 (Reapproved 1980), which is incorporated by reference. It is available from the American Society of Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103. It is also available for inspection at the Office of the Federal Register, Room 8401, 1100 L Street, NW., Washington, D.C. This incorporation by reference was approved by the Director of the Federal Register on November 8, 1982. This material is incorporated as it exists on the date of approval and a notice of any change in these materials will be published in the Federal Register.

2.3 Solvent Density. Determine the density of the solvent according to the procedure outlined in ASTM D 1475–60 (reapproved 1980). Make a total of three determinations for each coating. Report the density D_o as the arithmetic average of the three determinations.

3. *Calculations.*

3.1 Weight Fraction VOC. Calculate the weight fraction volatile organic content W_o using the following equation:

$$W_o = \frac{M_{ti1} + M_{cv1} - M_{cv2} - M_{ti2}}{M_{cv1} - M_{cv2}}$$

Report the weight fraction VOC W_o as the arithmetic average of the three determinations.

3.2 Volume Fraction VOC. Calculate the volume fraction volatile organic content V_o using the following equation:

$$V_o = \frac{\overline{W}_o \overline{D}_c}{\overline{D}_o}$$

4. *Bibliography.*

4.1 Standard Test Method for Density of Paint, Varnish, Lacquer, and Related Products. ASTM Designation D 1475–60 (Reapproved 1980).

4.2 Teleconversation. Wright, Chuck, Inmont Corporation with Reich, R. A., Radian Corporation. September 25, 1979. Gravure Ink Analysis.

4.3 Teleconversation. Oppenheimer, Robert, Gravure Research Institute with Burt, Rick, Radian Corporation, November 5, 1979. Gravure Ink Analysis.

[FR Doc. 82-30410 Filed 11-5-82; 8:45 am]

BILLING CODE 6560-50-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2183-3(a)]

Standards of Performance for New Stationary Sources; Petroleum Liquid Storage Vessels; Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for petroleum liquid storage vessels were promulgated in the Federal Register on April 4, 1980 (45 FR 23373). This action amends the standards by adding provisions allowing the use of a storage vessel primary seal that is considered by EPA to be equivalent to one of the primary seals required by the standards. This amendment implements Section 111(h) of the Clean Air Act and is based on the Administrator's determination that the primary seal in the Volume-Maximizing Seal system manufactured by R.F.I. Services Corporation is equivalent to the vapor-mounted foam-filled primary seal specified in the standards of performance.

EFFECTIVE DATE: December 1, 1982.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this amendment is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Docket.* A docket, number A-80-58, containing information considered by EPA in development of the amendment, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5624.

SUPPLEMENTARY INFORMATION: On April 29, 1981 (46 FR 23984), EPA published a notice of proposed determinations that two seal systems for petroleum liquid storage vessels, for which equivalency determinations were requested by the manufacturers, were not equivalent to volatile organic compound (VOC) emission control systems required by the standards of performance in Subpart Ka of 40 CFR Part 60. The final determinations are published elsewhere in this issue of the Federal Register. During the public comment period from April 29 to June 29, 1981, one of the manufacturers, R.F.I. Services Corporation, requested EPA to also determine equivalency for another one of its seal systems, the Volume-Maximizing Seal (VMS).

The VMS is essentially a combination of two Weather-Guard single seals. (The Weather-Guard single seal is the subject of the original equivalency determination requested by R.F.I.) The VMS uses an inverted Weather-Guard single seal as lower seal and an upper or secondary seal (also Weather-Guard single seal, but not inverted) to protect the lower seal from water and debris so a no-gap condition can be maintained. R.F.I. commented that the lower seal should be more than equivalent to a metallic shoe and the VMS equivalent to a shoe seal with a rim-mounted secondary seal. The VMS has a continuous vapor curtain hung from the lower seal to isolate the vapor space from the seal tip. R.F.I., therefore, believes the lower seal to be more than equivalent to a metallic shoe seal, which is noncompressive and which has fabric-to-metal expansion joints subject to potential leaks. R.F.I. calculations show emissions from a 100-foot diameter gasoline storage tank equipped with the VMS system to be 0.016 megagrams per year compared to 0.64 megagrams per year for a metallic shoe seal with a rim-mounted secondary seal.

EPA is unable to determine whether the VMS is equivalent to a metallic shoe seal with a secondary seal on the basis of the information provided by R.F.I. The R.F.I. emission calculations were based on the emissions calculated from leak rate data for the Weather-Guard single seal. This method of estimating emissions is felt to be invalid for this determination. Furthermore, at the public hearing held on May 28, 1981, R.F.I. referred to the VMS as "* * * nothing more than our single-seal system inverted close to the product with a similar secondary seal put above the product." No mention was made then of the continuous vapor curtain and the similarity to a metallic shoe seal. EPA believes that more information is needed to make an equivalency determination on the VMS lower seal as a metallic shoe seal. However, the lower seal with or without a vapor curtain is considered equivalent to a vapor-mounted foam log seal based on the fact that the seal is an inverted Weather-Guard single seal. As discussed in the proposed equivalency determination for the Weather-Guard single seal (46 FR 23984), emission tests for the foam-log seal used in EPS's determination on the Weather-Guard single seal because the two seals were considered analogous. An amendment to the NSPS for petroleum liquid storage vessels is, therefore, being promulgated to provide that the lower seal of the VMS system is equivalent to the vapor-mounted seal specified in Subpart Ka of 40 CFR Part 60.

The VMS systems is designed to allow the secondary seal to rise above the tank shell, thus allowing complete utilization of the tank capacity and a net saving of 3 to 4 percent of tank capacity, equal to tankage investment savings of $18,480 for a 100-foot diameter tank. R.F.I. has requested EPA to allow the VMS to be operated in this mode. They state that when the tank is full, the rim space is fully protected by the lower seal, and at all other times, the space is protected by two seals.

R.F.I. has overstated the saving in tank capacity by assuming the tank will be operated full 100 percent of the time. It is more realistic to assume the tank would be full only during peak periods, and the resulting investment savings would probably be a fraction of R.F.I.'s estimate. More important, however, is the potential for high VOC emissions when the secondary seal is out of the tank, leaving only a single seal to reduce emissions. Allowing the VMS to be operated in this manner would neither be consistent with the importance EPA has placed on the need for a double-seal system, nor with the Agency's conclusion on equivalency status for the Weather-Guard single seal. Therefore, it is concluded that the VMS system would be in compliance with the NSPS only if the secondary seal remains in contact with the tank wall.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so that they can intelligently and effectively participate in the rulemaking process. The contents of the docket will serve as

the record in case of judicial review (Sec. 307(d)(7)(A)).

Miscellaneous

The effective date of this regulation is December 1, 1982. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction, or modification of which was commenced after the date of proposal. This amendment applies to petroleum liquid storage vessels for which construction commenced after May 18, 1978, the date of proposal of the standards of performance.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source performance standard under Section 111(b) of the Act, or for any substantial revision of a standard. This equivalency determination is not considered to be a substantial revision of a standard. Therefore, no economic impact assessment was prepared for the equivalency determinations published in this Federal Register notice.

The Administrator certifies that a regulatory flexibility analysis under 5 U.S.C. 601 et seq. is not required for this determination. The determination will not have a significant impact on a substantial number of small entities because it does not impose any new requirements.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This equivalency determination is not major because it would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule."

This action was submitted to the Office of Management and Budget for review by Executive Order 12291.

List of Subjects in 40 CFR Part 60.

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc.

Dated: November 22, 1982.

Anne M. Gorsuch,

Administrator.

PART 60—[AMENDED]

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended by adding § 60.114a(c) to Subpart Ka as follows:

§ 60.114a Equivalent equipment and procedures.

* * * * *

(c) The primary vapor-mounted seal in the "Volume-Maximizing Seal" manufactured by R.F.I. Services Corporation is approved as equivalent to the vapor-mounted seal required by § 60.112a(a)(1)(i) and must meet the gap criteria specified in § 60.112a(a)(1)(i)(B). There shall be no gaps between the tank wall and any secondary seal used in conjunction with the primary seal in the "Volume-Maximizing Seal."

(Sec. 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601(a))

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40 CFR Part 60

[AD-FRL-2183-3(b)]

Standards of Performance for New Stationary Sources; Petroleum Liquid Storage Vessels; Notice of Final Equivalency Determinations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Rule-related notice; notice of final equivalency determinations.

SUMMARY: This is a notice of EPA's determination that two seal systems for petroleum liquid storage vessels, for which equivalency determinations were requested by the manufacturers [Pittsburgh-Des Moines Corporation (PDM) and R.F.I. Services Corporation (R.F.I.)], are not equivalent to the volatile organic compound (VOC) emission control systems required by the standards of performance in Subpart Ka of 40 CFR Part 60.

ADDRESSES: *Docket.* Docket No. A-80-58, containing supporting information used in making the determinations, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5624.

SUPPLEMENTARY INFORMATION:

Final Equivalency Determinations

On April 29, 1981 (46 FR 23984), EPA published a notice of proposed determinations that two seal systems for petroleum liquid storage vessels, for which equivalency determinations were requested by the manufacturers, were not equivalent to volatile organic compound (VOC) emission control systems required by the standards of performance in Subpart Ka of 40 CFR Part 60. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed determinations, a public hearing was held on May 28, 1981, in Research Triangle Park, North Carolina. In addition, during the public comment period from April 29 to June 29, 1981, eight comment letters were received.

After careful consideration of the comments presented at the public hearing and in letters received during the public comment period, EPA has concluded that the proposed determinations should not be changed. Therefore, the final determinations are that neither the PDM TUBESEAL®/ Weathershield system nor the R.F.I. Weather-Guard single seal is equivalent to seal systems required by the standards of performance for petroleum liquid storage vessels in 40 CFR 60.112a. The main reason for these denials of equivalency status is that gaps can be expected to develop between the seals and tank walls over a period of time, and when gaps occur, the performance of these candidates seal systems is clearly not equivalent to the equipment required by the standards. The fact that gaps occur is supported by specific inspection data submitted by commentors as well as a statement of general knowledge common to storage tank owners and regulatory agencies. The complete rationale for these denials of equivalency appeared in the proposed determinations (46 FR 23984, April 29, 1981) and remains unchanged. EPA's responses to major comments received since April 29 are discussed below. A more detailed discussion of comments and EPA's responses is included in Docket Number A-80-58.

Significant Comments and EPA's Responses

Comments were received from the two companies requesting equivalency,

petroleum storage tank owners and operators, and State and local air pollution control agencies. Most of the comment letters contained multiple comments which have been categorized for discussion. The equivalency determinations are discussed separately below.

PDM's TUBESEAL®/Weathershield

In the original request for equivalency and in comments subsequent to the proposed denial of equivalency, PDM submitted data and information in support of its claim that the "* * * TUBESEAL®/Weathershield system is more than equivalent to the shoe seal with secondary and hence should itself receive equivalency status." The primary basis for the equivalency request was a set of emission test data taken by PDM which compared the efficiency of the TUBESEAL® system to the shoe seal system. The tests were conducted with no gaps in the TUBESEAL® and large gaps (inherent in the design) in the Weathershield, and no gaps in either the shoe seal or its secondary. Under these test conditions, the data indicated that the TUBESEAL® system was more efficient that the shoe seal system. PDM contends that the TUBESEAL® can be operated without gaps and, therefore, a Weathershield, even with its large gap area, is sufficient to make the system equivalent to a shoe seal system, and a continuous secondary seal is not necessary.

EPA does not believe that the TUBESEAL® can always be operated without gaps, based on inspection data discussed later in this notice. Further, Chicago Bridge and Iron Company (CBI) test data, on which the equivalency determination is based, indicate that when gaps are introduced in a liquid-mounted, liquid-filled seal like the TUBESEAL®, emissions increase at a significantly higher rate than they do from a metallic shoe seal with comparable gaps. In the CBI tests, when gap areas in the metallic shoe seal were increased from 0 to 14 square inches per foot of tank diameter, there was only about a 50 percent increase in emissions, whereas emissions from the liquid-mounted, liquid-filled seal increased by about 300 percent when the gap area increased from 0 to 2.4 square inches per foot of tank diameter. These data illustrate the importance of a continuous secondary seal when the primary has gaps, particularly when the primary is a liquid-mounted, liquid-filled seal.

PDM's comments on the proposed denial of equivalency were primarily concerned with the basis for the determination. PDM commented that (1) EPA should have based the determination on emission data taken by PDM under gap-free conditions rather than on CBI data taken with gaps in the seals; (2) EPA assumed too high an emission reduction efficiency for continuous secondary seals and too low an efficiency for the PDM Weathershield; (3) EPA did not consider PDM data that showed the TUBESEAL® system to be more efficient than the metallic shoe seal system even when temperatures under the TUBESEAL® approached the product's boiling point, but the same conditions did not exist under the shoe seal; (4) EPA should consider factors other than emission reduction, such as cost effectiveness, fire hazard potential, and corrosiveness of the seal system, in making the final determination.

Effect of Gaps on Seal System Performance

PDM commented that EPA assumptions concerning gap areas on liquid-mounted primary seals do not reflect actual conditions on at least two-thirds of the tank population and, therefore, should not be used for determining equivalency for the TUBESEAL®/Weathershield system. PDM submitted inspection data it collected in 1977 for 38 tanks equipped with TUBESEALS® which showed that two-thirds had no gaps between the seal and tank wall. This percentage was similar to that for tanks inspected in 1976–1977 by local regulatory agencies which were equipped with resilient primary seals, an uncertain number of which were liquid-filled liquid-mounted seals.

EPA agrees that the inspection data cited by PDM indicate that, at any given time, a large percentage of liquid-mounted seals can be expected to operate without gaps. However, the data also indicate that as many as one-third of the seals inspected had gaps. Without evidence to the contrary, EPA assumes that all the seals inspected were properly installed and well maintained. Therefore, emission data obtained while gaps were between the liquid-mounted seal and tank wall reflect actual field conditions for at least a portion of the tank population and are appropriate for use in evaluating seal system performance.

The San Diego Air Pollution Control District commented that the PDM TUBESEAL®/Weathershield system would be equivalent to a vapor-mounted primary seal with a continuous secondary seal if the TUBESEAL® could be maintained with gaps no wider the 1/16 inch, it would not be used where freezing of liquid in the TUBESEAL® is possible, and there would be a weekly inspection by tank owners. The District emphasized that it would be very difficult to ensure that these conditions are met in the field. This comment supports EPA's position that under normal operating conditions, the PDM system is not equivalent.

PDM commented that EPA's assumptions about seal gaps were unrealistic and should not have been used in the equivalency determination for the TUBESEAL® system. EPA evaluated effects of primary seal gaps ranging from 2.4 to 10.0 square inches per foot of tank diameter, and the CBI pilot tank tests included primary seals with gaps of 1.3 to 14.7 square inches. PDM has stated that primary seal gaps of 10.0 square inches are extreme, and a gap area of 2.4 square inches would indicate a totally failed liquid-mounted seal.

EPA agrees that a gap area of 10.0 square inches per foot of tank diameter is unrealistic for a liquid-mounted seal and, therefore, did not use it in making the final determination. PDM's statement that a gap area of 2.4 square inches per foot of tank diameter represents a failed seal is inconsistent with field inspection data mentioned earlier that showed gap areas greater than 2.4 square inches. It is also inconsistent with PDM's own request that a gap area of 4.7 square inches per foot of tank diameter be allowed for the TUBESEAL®. EPA's use of emission data under varying gap areas was intended to illustrate the fact that with any gap in the primary seal, regardless of the size, the effectiveness of a Weathershield is less than that of a continuous secondary seal.

Secondary Seal Performance

PDM commented that EPA's proposed determination was based on an emission reduction efficiency that was too high for continuous secondary seals (78 percent). The basis for the comment was the emission data from one test conducted by PDM that showed that the rim-mounted continuous secondary seal was only 50 percent efficient in reducing emissions from the primary metallic shoe seal. Thus, according to PDM, it can be assumed that fully tight secondary seals (over all types of primary seals) are only 50 percent effective in reducing emissions.

EPA carefully reviewed the data submitted by PDM and could not determine the reasons for the low efficiency for the secondary seal in the PDM test. Therefore, EPA decided to use data taken from several tests by CBI on a 20-foot diameter pilot test tank to

evaluate the secondary seal's performance. These tests were conducted under varying conditions and with different types of primary seals. In all the CBI tests, the efficiency of secondary seals was shown to be greater than the 50 percent claimed by PDM. When used with a metallic shoe primary seal, the efficiency of the secondary was 88 percent (no gaps in either seal and parameters normalized to a windspeed of 5.4 mph and a 7.5 psia true vapor pressure of stored gasoline). In addition, API Publication 2517, "Evaporation Loss from External Floating-Roof Tanks, Second Edition," February 1980, presents loss equations for determining emissions from representative tank populations ("average" seal factors) and from field tanks with essentially no gaps in their seal system ("tight" seal factors). Using these factors, the efficiency of a continuous secondary seal over a metallic shoe primary seal at the PDM normalized field test condition is calculated to be greater than 92 percent.

In specific CBI tests of fully tight secondary seals over fully tight liquid-mounted and vapor-mounted primary seals, the secondary seal efficiencies were 78 and 96 percent, respectively. The "average" seal efficiencies calculated from API 2517 are 77 and 72 percent, respectively.

Based on the specific CBI tests, EPA selected 78 percent efficiency for a secondary seal over a liquid-mounted primary seal in determining equivalency of the PDM TUBESEAL® Weathershield to the standards of performance.

PDM also commented that EPA used too low an efficiency for the Weathershield in making the determination. Their position is that the PDM Weathershield is unique and not "typical" as inferred in the proposed equivalency determination. The Weathershield is bolted and gasketed to the rim of the pontoon and has self-flexing shields which improve shield-to-tank wall contact and shield-to-shield contact. In PDM's 35-foot diameter test tank, gaps between the shields and tank wall varied from 0 to ¼ inch and between the shields from 0 to ⅝ inch. Shield-to-wall gap area was estimated to be 136 square inches and shield-to-shield gap area 59 square inches for a total of 195 square inches. In contrast, the Weathershield tested on the CBI pilot tank had gaps between the shields and tank wall ranging from ½ inch to 1 3/16 inches; and the shields were hinge mounted to the pontoon rather than gasketed, which allowed a large gap around the entire base. The CBI tests show this very "loose" Weathershield to be 50 percent efficient while a tight fitting secondary is 78 percent efficient. Based on these data, PDM believes the efficiency of its Weathershield should be somewhere in between.

EPA does not agree that the CBI test data support PDM's claim that the efficiency of PDM's Weathershield is between 50 and 78 percent. In fact, the data indicate that the efficiency of the PDM Weathershield is comparable to that of a loose-fitting Weathershield or loose-fitting secondary seal. The CBI data show that a fully tight secondary seal is 78 percent efficient. They also show that both a loose-fitting Weathershield with a gap area ranging from 9 to 27 square inches per foot of tank diameter and a loose-fitting secondary seal with a gap area of 4.87 square inches per foot of tank diameter are about 50 percent efficient. This indicates that the existence of a large gap area (greater than 1 square inch per foot of tank diameter) is the main reason for the decrease in efficiency. The relative sizes of the gap areas apparently had little effect on the test results since the efficiency remained at about 50 percent even though the gap areas ranged from 4.87 to 27 square inches per foot of tank diameter. The Weathershield tested by PDM had a gap area of 5.6 square inches per foot of tank diameter and, thus, could be expected to exhibit the same efficiency as the CBI Weathershield and loose-fitting secondary seal.

Performance of PDM TUBESEAL® System v. Metallic Shoe Seal System

PDM believes its test data demonstrate that the TUBESEAL®/Weathershield is 2½ times more efficient than the metallic shoe seal with a secondary seal. PDM contends that the tests were conducted during a period that included many days when temperatures under the TUBESEAL® approached the boiling point of the product, but temperatures under the metallic shoe seal did not approach the boiling point. Therefore, according to PDM, the efficiency of the TUBESEAL® system is probably even greater than 2½ times that of the shoe seal system.

EPA has reviewed the PDM test data and agrees that for those particular tests, the TUBESEAL® system appeared to be more efficient than the metallic shoe seal system. However, as stated earlier, the efficiency results for the secondary seal over the shoe seal were unusually low (50 percent efficiency) when compared to the CBI test data. With a secondary seal efficiency of 88 percent based on CBI tests, the emissions of 17.3 lbs per day from the metallic shoe seal system would be reduced to 2.1 lbs per day or 1.8 times *more* efficient than the TUBESEAL® Weathershield.

The second part of PDM's comment—that if temperatures under the shoe seal had approached the boiling point of the product, it would have been even less efficient than the TUBESEAL®—is not supported by the data. During the 106-day TUBESEAL® system test, there were only about 9 days (days 49–52 and 73–77) when the highest *peak* temperatures of the liquid 1 inch under the seal were near the boiling point (95°F to 97°F). The average temperature was from 17°F to 20°F lower. The test of the metallic shoe seal without a secondary seal was also conducted during warm weather. During the warmest 36 consecutive test days, the peak temperature 1 inch below the liquid surface was 84°F, and the average temperature was only about 10°F lower. These data suggest that possibly, the higher temperatures recorded for the TUBESEAL® are a result of seal design rather than atmospheric conditions. The TUBESEAL® resting on the liquid surface in the rim space may allow a high rate of heat transfer through the seal to the liquid underneath. In any case, the data do not support the contention that emissions for the metallic shoe seal would have been higher if both seals had been tested under the same conditions, but do suggest that under similar atmospheric conditions, the temperature of the liquid stored may peak at a higher level when the TUBESEAL® is used.

General

PDM commented that EPA should consider factors other than emission reduction effectiveness in evaluating the TUBESEAL® system. Specifically, PDM asked for consideration of the TUBESEAL® system's lower cost relative to an NSPS seal system, the lessened risk of rim fires with a TUBESEAL® due to the absence of a vapor space, and the noncorrosive TUBESEAL® material. Section 111(h)(3) of the Act specifies that a determination of equivalency is based on whether a system's reduction in emissions is equivalent to that required by an NSPS. Other factors are irrelevant. Therefore, the Administrator does not consider the factors mentioned by PDM to be applicable to this equivalency determination.

R.F.I. Corporation's Weather-Guard Single Seal

In the original request for equivalency, R.F.I. submitted data from leak rate tests to estimate emissions from the R.F.I. Weather-Guard single seal. R.F.I.'s

request and subsequent comments were primarily based on its interpretation of the leak rate data and calculations of VOC emission rates from the leak rate data. All of R.F.I.'s data and calculations were also based on the assumption that the Weather-Guard single seal would be able to be operated with no gaps between the seal and the tank wall. In the proposed determination that the R.F.I. seal is not equivalent to equipment required in 40 CFR 60, Subpart Ka, EPA concluded that leak rate data cannot be used to compare emissions from the R.F.I. seal to those from a double seal required by Subpart Ka, and that the R.F.I. seal can be expected to develop gaps during its service life.

During the public comment period, R.F.I. submitted comments to support its positions concerning the lack of gaps with a Weather-Guard single seal, the use of leak rate data to calculate emissions, and the low cost of the Weather-Guard single seal in comparison to a double-seal system. R.F.I. also requested that its Volume-Maximizing Seal system be approved as equivalent to the standards of performance for petroleum liquid storage vessels. Several oil companies submitted comments in support of R.F.I.'s request for equivalency for the single seal, and two air pollution control agencies commented in support of EPA's determination. The major issues raised in the comments are discussed below. A more detailed summary of comments and EPA's responses are included in Docket No. A-80-58.

Gaps in the Weather-Guard Single Seal

R.F.I. disagreed with EPA's main reason for proposing the denial of equivalency for the Weather-Guard single seal—that the seal can be expected to have gaps during normal operation between inspections. R.F.I. stated that the seal is specifically designed to maintain a no-gap condition at all times. In support of this position, R.F.I. states that worst-case testing conducted on specially prepared surface defects and out-of-round shell surfaces, and lifetime equivalent testing conducted for contact, wear resistance, and continued integrity indicated that the seal will not have gaps as long as the plates are intact and easily seen in a visual inspection. Inspection results for nine in-service tanks were submitted by tank owners in support of R.F.I.'s position. Not all of the seals inspected were gap-free, but the commenters explained that the gaps could be eliminated through minor repair or tank design change.

The information provided by the commenters indicated that all of the nine seals inspected had been in service from 1 month to less than 2 years, whereas R.F.I. predicts a Weather-Guard seal life of 15 years. Thus, EPA believes that the condition of this small sampling of seals cannot necessarily be considered representative of what might occur over a 15-year period.

The California Air Resources Board commented in support of EPA's proposed determination on the Weather-Guard single seal. The San Diego Air Pollution Control District also provided comments and inspection data supporting the position that the Weather-Guard cannot maintain a gap-free condition except under unusually favorable tank conditions. During the 6-month period from June to December 1980, the San Diego District made 14 individual inspections on a Weather-Guard seal installed in a tank that was off-level and out-of-round, conditions that commonly develop in many tanks over a period of time. Gaps were found in almost all of the inspections. The District recommended, therefore, that EPA not grant equivalency to the Weather-Guard single seal. The District's inspection data conflict with R.F.I.'s claim that the Weather-Guard will not gap even under worst-case conditions. After carefully considering all the inspection data submitted by commenters, EPA continues to believe that the R.F.I. Weather-Guard single seal cannot routinely be maintained in a gap-free condition.

Calculating VOC Emissions from Leak Rate Data

R.F.I. attempted to compare emissions from the Weather-Guard single seal to those from a primary vapor-mounted foam seal with a secondary flapper seal by injecting nitrogen under the single seal and under the foam seal and measuring the quantity of nitrogen required to maintain the same constant fixed pressure under each seal. EPA had concluded that these leak-rate tests did not create annular circumferential flows of air and hydrocarbon caused by wind-induced pressure differentials on the floating roof resulting from wind flow over the tank and, therefore, cannot be used to compare a single seal to a double seal. R.F.I. commented that EPA's conclusion is incorrect and, to support its position, submitted data and hydrocarbon concentrations measured with an explosimeter in the vapor space under the Weather-Guard in several in-service tanks. The data did not reflect the effect of wind-induced air flow under the seal on hydrocarbon concentrations. R.F.I. concluded, therefore, that there was no air flow under the tight-fitting Weather-Guard single seal; and that a leak-rate test, therefore, does represent a realistic evaluation of emission potential for seals with no gaps.

EPA has reviewed R.F.I.'s comments and information. However, it remains EPA's conclusion that the leak rate tests performed by R.F.I. do not provide a valid comparison of the performance of the R.F.I. Weather-Guard single seal and the vapor-mounted foam log primary seal with a secondary flapper seal (double seal). As discussed in the following paragraphs, there are several reasons for this conclusion.

The principal factors which affect the rate of vapor leakage from an external floating roof tank with vapor-mounted seals are (1) the size of any gaps which exist in the seal or between the seal and tank wall, and (2) the pressure differential across the gaps. Pressure differentials across a gap are primarily caused by the wind moving across the surface of the storage tank's external floating roof. The wind causes negative pressures along a part of the seal circumference and positive pressures along other portions of the seal. Positive pressures force air into gaps and negative pressures force vapors out of gaps into the atmosphere, causing the air to flow circumferentially around the seal in the vapor space. While smaller gap areas produce smaller leak rates, even tight or so-called "no gap" seals have finite gaps and are thus affected by wind-induced pressure on the seal. The concentration measurements made by R.F.I. in the vapor space under the Weather-Guard single seal cannot be used as an indicator of wind-induced airflow under the seal (or lack thereof) as R.F.I. attempted to do. The data from the measurements showed that hydrocarbon concentrations did not increase in the direction of the flow path as R.F.I. expected they would if there were wind-induced circumferential flow. However, the windsweep is very low under a tight seal, and the hydrocarbon concentration in the vapor space is essentially at the 100 percent saturation level. As a result, concentrations would be fairly constant at all locations in the vapor space. Therefore, the concentration data taken by R.F.I. are not useful as an indicator of wind-induced airflow under a vapor-mounted seal caused by pressure differentials along the seal circumference.

In the case of vapor-mounted single seals, the pressure differentials induced by the wind are similar from seal to seal. As a result, it is possible to compare the performance of different vapor-mounted single seals by using leak rate tests. However, it has not been

shown that double seals can be compared in this way; nor can single seal performance be compared to double seal performance using a leak rate test. The reason is that the secondary seal in a double seal system tends to insulate the primary seal from the pressure effects and wind-sweep caused by wind moving across the top of the tank. As such, for any given wind condition the pressure differential and wind-sweep effects across a primary seal in a double seal system would probably be less than for a single seal. Since the leak rate tests performed by R.F.I. compared single versus double seals at equal pressures under the primary vapor-mounted seals, the results are unrepresentative of actual conditions and yield invalid comparisons.

Moreover, the R.F.I. leak rate tests were performed on tanks with seals having essentially no gaps. As described in the previous section, this is not representative of expected field conditions and serves primarily to show only the relative tightness of the two seals.

Miscellaneous

R.F.I. and other commenters stated that EPA should consider the Weather-Guard's lower cost relative to the NSPS seal system in determining equivalency. Section 111(h)(3) of the Act specifies that a determination of equivalency is based on whether a system's reduction in emissions is equivalent to that required by an NSPS. Other factors are irrelevant. Therefore, the Administrator does not consider cost considerations to be applicable to this equivalency determination.

One commenter stated that EPA should establish test criteria for determining equivalency under the NSPS for petroleum liquid storage vessels so that innovative and cost-effective control technology may be evaluated expeditiously without subsequent questioning of the test parameters and scope. R.F.I. said that if EPA contends that "emission test data such as obtained on specific seal and seal systems in the Chicago Bridge and Iron (CBI) test facility can serve as the best technological basis * * *," then it must also concede that only those seal genders tested in the CBI facility will be available for use because that test facility is the only one in existence.

EPA agrees that a simple and quick means of determining equivalency is desirable. However, at this time specific test criteria that would be applicable for every type of seal technology for which equivalency may be requested are not feasible. Ideally, actual emission data should be used to make equivalency determinations. EPA recognizes, however, that emission testing either in a facility similar to CBI's or by actual field testing is very expensive and time-consuming. The generic seal systems tested by CBI do represent the best measurements of VOC emissions available for equivalency determinations. However, EPA will consider other information such as leak rate data, engineering specifications, and inspection data to be used in conjunction with CBI or similar tests in making determinations. For example, the leak rate data from the R.F.I. field test on the Weather-Guard single seal was essentially the same as the CBI leak rate test on a primary vapor-mounted foam log seal without a secondary seal. EPA concluded that the leak rate data could be used to compare the effectiveness of these single seals and used the CBI vapor-mounted foam seal emissions data for evaluation. There were no CBI or other data relating emissions from a vapor-mounted foam log seal with a rim-mounted continuous secondary seal to leak rate. On this basis, EPA rejected leak rate data on the double-seal system as a basis for the determination.

Several commenters noted that EPA's proposed denial of NSPS equivalency has caused concern by many companies that State regulations which permit installation of the Weather-Guard single seal on existing tanks will be negated. They requested EPA to make it clear that the NSPS determination in no way affects equivalency determinations made by States relative to CTG requirements for existing tanks. EPA agrees that this determination only pertains to new tanks and does not involve consideration of tanks which have an existing Weather-Guard seal system in place.

A related comment made by R.F.I. was that EPA should allow the use of the Weather-Guard single seal over a "nonconforming" (not in compliance with CTG requirements) primary seal on existing tanks. Again, this would be a determination to be made by individual States and is not related to this equivalency determination. In making such a determination, it is expected that a State would consider the information presented in this notice but would also consider other information such as the condition and gap status of the tank and the existing primary seal.

The R.F.I. Volume-Maximizing Seal

In the letter containing comments on the equivalency determination for the Weather-Guard single seal, R.F.I. requested equivalency for its Weather-Guard Volume-Maximizing Seal (VMS). The VMS uses an inverted Weather-Guard single seal as a lower seal and an upper or secondary seal (also a Weather-Guard single seal, but not inverted) to protect the lower seal from water and debris so a no-gap condition can be maintained. R.F.I. commented that the lower seal should be more than equivalent to a metallic shoe seal and the VMS equivalent to a shoe seal with a rim-mounted secondary seal. The equivalency determination for the VMS is discussed earlier in this document.

Docket

The docket is an organized and complete file of all the information considered by EPA in these determinations of equivalency. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and final determinations and EPA responses to significant comments, the contents of the docket will serve as the record in cases of judicial review (Sec. 307(d)(7)(A)).

Miscellaneous

The Administrator certifies that a regulatory flexibility analysis under 5 U.S.C. 601 et seq. is not required for these determinations. The determinations will not have a significant impact on a substantial number of small entities because they do not impose any new requirements. In addition, since the determinations do no more than deny requests for Agency action, they are not "rules" for the purposes of 5 U.S.C 601 *et seq.*

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. These equivalency determinations are not major because they would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule."

This action was submitted to the Office of Management and Budget for review as required by Executive Order 12291.

Dated: November 22, 1982.

Anne M. Gorsuch,

Administrator.

[FR Doc. 82-32807 Filed 11-30-82; 8:45 am]

BILLING CODE 6560-50-M

40 CFR Part 60

[AD-FRL-2224-7]

Standards of Performance for New Stationary Sources; VOC Fugitive Emission Sources; Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standards would limit emissions of volatile organic compounds (VOC) from fugitive emission sources in the petroleum refining industry. The proposed standards would: (1) Require a leak detection and repair program to reduce VOC emissions from pumps and valves; and (2) specify the use of certain equipment to reduce VOC emissions from compressors, sampling connection systems, and open-ended valves. The proposed standards would also allow no detectable emission from pressure relief devices during normal operations.

The proposed standards implement the Clean Air Act and are based on the Administrator's decision that fugitive emission sources of VOC in the petroleum refining industry contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. As required by Section 111 of the Clean Air Act, the proposed standards are intended to require new, modified, and reconstructed sources in the petroleum refining industry to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health and environmental impact and energy requirements.

A public hearing will be held to provide interested persons an opprotunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments:* Comments must be received on or before March 21, 1983.

Public Hearing. If anyone contacts EPA requesting to speak at a public hearing by February 11, 1983, a public hearing will be held on February 23, 1983 beginning at 10 a.m. Persons interested in attending the hearing should call Mrs. Naomi Durkee at (919) 541-5578 to verify that a hearing will occur.

Requests to Speak at Hearing. Persons wishing to present oral testimony must contact EPA by February 21, 1983.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate, if possible) to: Central Docket Section (A-130), Attention: Docket No. A-80-44, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

Public Hearing. If anyone contacts EPA requesting a public hearing, the public hearing will be held at the Office of Administration Auditorium, Research Triangle Park, N.C. Persons interested in attending the hearing should call Mrs. Naomi Durkee at (919) 541-5578 to verify that a hearing will occur.

Persons wishing to present oral testimony should notify Mrs. Naomi Durkee, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

Background Information Document. The background information document (BID) for the proposed standards is contained in the docket and may be obtained from the U.S. EPA library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "VOC Fugitive Emissions In Petroleum Refining Industry—Background Information for Proposed Standards" (EPA-450/3-81-015a).

Docket. Docket No. A-80-44, containing supporting information used in developing the proposed standard, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Ms. Susan R. Wyatt, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

SUPPLEMENTARY INFORMATION:

Summary of Proposed Standards

The proposed standards of performance cover fugitive emission

sources of volatile organic compounds (VOC) within petroleum refineries. The proposed standards would apply to new, modified, and reconstructed compressors and new, modified, and reconstructed fugitive emission sources within process units. The proposed standards would reduce fugitive emissions of VOC from pumps, valves, sampling connections, pressure relief devices and open-ended valves in VOC service within process units and from compressors in VOC service. "In VOC service" means that a fugitive emission source contains or contacts a fluid containing 10 or more percent by weight VOC.

The proposed standards are different from most standards of performance because they are mainly work practices and equipment standards rather than emission standards and they cover several emission sources. The proposed standards would require: (1) A leak detection and repair program for valves in gas or light liquid service and for pumps in light liquid service; (2) certain equipment for compressors, sampling connection systems, and open-ended valves; and (3) no detectable emissions from pressure relief devices in gas service during normal operation. "In gas service" means that a fugitive emission source contains VOC fluids in the gaseous or vapor state. "In light liquid service" means that a fugitive emission source contains VOC liquids which will have more than 10 percent of the liquids evaporated at a boiling point of 150° C, as determined by ASTM Method D 86. While still assuring that equivalent emission reduction will be achieved, the proposed standards allow the use of alternative equipment for valves, pumps, compressors and sampling connection systems. In addition, the proposed standards provide alternative standards for valves and a procedure for determining the equivalency of alternative control measures.

Summary of Environmental, Energy, and Economic Impacts

The proposed standards of performance would reduce fugitive emissions of VOC from new, modified, and reconstructed compressors and process units (production facilities) by about 70 percent from the emission levels that would result with control means currently practiced by the industry. In 1986, the proposed standards would reduce uncontrolled fugitive emissions of VOC from new, modified, and reconstructed production facilities by approximately 46,000 megagrams (Mg), a reduction of emissions from 64,000 megagrams of VOC per year (Mg/yr) to about 18,000 Mg/yr. By 1986, some States will require control of petroleum refinery fugitive emission sources of VOC through their State implementation plans (SIP's). Consequently, the VOC emission reduction attributable to the proposed standards after these SIP's are established by 1986 would be 31,000 Mg, a reduction of emissions from 49,000 Mg/yr to about 18,000 Mg/yr.

The proposed standards or performance would not increase the energy usage within petroleum refineries. In general, the controls required by the proposed standards do not require energy. Furthermore, the effect of the proposed standards would be to increase efficiency of raw material usage, so that a net positive energy impact would result. Implementation of the proposed standards could result in a minor adverse solid waste impact. In contrast, the proposed standards would also cause a positive impact on water quality by containment of potential liquid leaks.

The proposed standards would require a cumulative capital investment of $8.2 million for newly constructed production facilities and up to $19.0 million for modified and reconstructed production facilities through 1986. This capital investment would not defer construction of petroleum refinery units. The industry-wide net annualized cost for new, modified, and reconstructed production facilities could be as much as $8.2 million in 1986. These costs would be distributed among about 100 newly constructed production facilities and up to 182 modified and reconstructed production facilities that could be affected by 1986. Significant price increases are not expected to result from implementation of these standards because the annualized cost of the proposed standards is a small fraction (0.1 percent or less) of the yearly revenue expected from new, and modified, reconstructed production facilities.

Rationale

Selection of Sources and Pollutants

The Priority List (40 CFR 60.16, 44 FR 49222, August 21, 1979) includes, in order of priority for standards development, various major source categories that the Administrator has determined contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The order of the listed categories is based on consideration of the three factors specified in Section 111(f) of the Clean Air Act: (1) The quantity of air pollutant emissions which each category will be designed to emit, (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare, and (3) the mobility and competitive nature of each category. The Priority List identifies the source categories for which EPA must promulgate standards of performance. The category "Petroleum Refineries: Fugitive Sources" ranks third on the list.

Fugitive emission sources at petroleum refineries include compressors, pumps, valves, flanges, pressure relief devices, open-ended valves, sampling connection systems, process drains, wastewater separators, and cooling towers. Process drains and wastewater separators are part of the wastewater system within a petroleum refinery. Studies are currently being conducted which should allow development at a later date of standards of performance for fugitive emission sources which are part of a refinery wastewater system. Presently available refinery data on cooling towers indicate that new cooling towers use indirect heat transfer and that emissions from these cooling towers are much less than emissions from cooling towers that use direct heat transfer. Additionally, control techniques for indirect cooling towers are not well defined. Adequate information is available, however, to develop standards of performance for compressors, pumps, flanges, valves, pressure relief devices, sampling connection systems, and open-ended valves. Therefore, EPA selected compressors, pumps, flanges, valves, pressure relief devices, sampling connection systems, and open-ended valves as the fugitive emission sources covered by the proposed standards.

Fugitive emission sources covered by the proposed standards emit volatile organic compounds (VOC) that contribute to atmospheric photochemical reactions. As discussed in Appendix E of the BID, about 100 newly constructed production facilities and as many as 182 modified or reconstructed production facilities could become covered by the proposed standards during the period from 1982 to 1986. If the fugitive emission sources covered by the proposed standards in these 282 production facilities are controlled only by existing maintenance procedures, an estimated 64,000 megagrams of VOC per year (Mg/yr) would result from these facilities in 1986. If however, these sources are controlled by SIP's in States not attaining the national ambient air quality standard (NAAQS) for ozone and by existing maintenance procedures in States attaining the NAAQS for ozone, an estimated 49,000 Mg/yr would

result from these facilities in 1986. The proposed standards, as presented in this preamble, would reduce these emissions to about 18,000 Mg/yr in 1986.

In summary, as required by Section 111(f) of the Clean Air Act, EPA selected fugitive emission sources at petroleum refineries as a source category for which EPA must promulgate standards of performance. After considering the adequacy of available information, EPA decided to propose standards for compressors, pumps, flanges, valves, pressure relief devices, sampling connection systems, and open-ended valves. In 1986, emissions of VOC would be reduced by at least 31,000 Mg/yr for the fugitive emission sources covered by the proposed standards.

Standards of performance have other benefits in addition to achieving emissions reductions. Standards of performance establish a degree of national uniformity to air pollution standards, and, therefore, preclude situations in which some States may attract new industries as a result of having relaxed standards relative to other States. Further, standards of performance provide documentation that reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in NAAQS attainment areas and of lowest achievable emission rates (LAER) for facilities located in NAAQS nonattainment areas. This documentation includes identification and comprehensive analyses of alternative emission control technologies, development of associated costs, evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. This documentation also provides an economic analysis that reveals the affordability of controls in a study of the economic impact of controls on an industry.

The rulemaking process that establishes standards of performance ensures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant standards represent a balance in which government resources are applied in a well publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

Selection of Affected Facilities

The choice of the affected facility for the proposed standards is based on EPA's interpretation of Section 111 of the Clean Air Act and on the judicial construction of its meaning [ASARCo, Inc., v. EPA, 578 F.2d 319 (D.C. Cir. 1978)]. Under Section 111, standards of performance for new stationary sources must apply to "new sources;" "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" [Section 111(a)(3)]. Most industrial plants, however, may consist of numerous facilities—equipment or groups of equipment—which emit air pollutants and which, consequently, may be viewed as "sources." EPA uses the term "affected facility" to designate the equipment or groups of equipment, within a particular kind of plant, chosen as the "source" affected by given standards of performance.

In choosing the affected facility, EPA must decide which equipment or groups of equipment is the appropriate unit, or the "source," for separate standards of performance in the particular industrial context involved. EPA must do this by examining the situation in light of the terms and purpose of Section 111 of the Clean Air Act. One major consideration in determining the definition of a source is that the use of a narrower designation results in bringing replacement equipment under standards of performance sooner. If, for example, an entire plant is designated as the affected facility, no part of the plant would be covered by the standards unless the plant as a whole is "modified" (see 40 CFR 60.14) or "reconstructed" (see 40 CFR 60.15). The plant as a whole could be considered modified only if the replacement resulted in an increase in the aggregate emissions from the entire plant. The plant as a whole could be considered reconstructed only if the cost of the replacement exceeded 50 percent of the cost of an entire new plant. If, on the other hand, each piece of equipment is designated as an affected facility, then as each piece is replaced, the replacement piece will be a new source subject to the standards regardless of the cost of the replacement or whether the replacement caused emissions from the plant as a whole to increase. Since the purpose of Section 111 is to minimize emissions by application of the best demonstrated system of emission reduction at all new and modified sources (considering cost, nonair quality health and environmental impacts, and energy requirements), there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources within plants will be brought under the coverage of the standards as they are installed. This presumption can be overcome, however, if EPA concludes either that: (a) A broader designation of the affected facility would result in greater emission reduction; or (b) consideration of the other relevant statutory factors (technical feasibility, costs, nonair quality health and environmental impacts, and energy requirements) leads to the conclusion that a broader designation is appropriate.

Affected facilities for standards that would cover fugitive emission sources could be defined as individual emission sources (equipment components), groups of equipment components that are operated in conjunction with each other (process units), or groups of process units at one location (plant sites). In determining which alternative definition of affected facilities to select for petroleum refinery fugitive emission sources, EPA first considered the roles of modifications and reconstructions and how they affect the overall emission reduction potential for these sources. As a result, EPA concluded that a definition of an affected facility which is based on the plant site would provide the lowest emission reduction potential. It was further concluded that a definition that is based on equipment components would provide an emission reduction potential similar to a definition that is based on process units. Therefore, EPA rejected the plant site basis and considered the equipment component basis and process unit basis definitions, in conjunction with other relevant factors, before defining the affected facility for petroleum refining fugitive emission sources.

The alternative of defining facilities on the basis of equipment components was reviewed first. Equipment components (such as pumps and valves) are typically much smaller than the average source covered by Section 111, and there are many of these equipment components per process unit. If EPA selected equipment components as the basis for defining affected facilities, situations would arise in which replaced equipment components in existing process units would be subject to the standards, while adjacent components would not be subject to the standards. With such a mixture of new and existing components, the effort to keep track of equipment components covered by the standards and components not covered by the standards would be costly. Implementing a leak detection and repair program, the principal control technique considered for the proposed standards, for a very small proportion of all the equipment components at a plant site would be too costly. As discussed below, compressors are an exception to

these considerations. Therefore, EPA rejected the equipment component designation for fugitive emission sources other than compressors. Consequently, EPA examined the next most narrow alternative (the group of equipment components within a process unit) for fugitive emission sources other than compressors.

The alternative of defining an affected facility as the group of equipment components, other than compressors, within a process unit would achieve as much emission reduction as the first alternative. In addition, it would have no associated cost of distinguishing between those sources covered by the standards and those not covered. Consideration of the other relevant statutory factors did not lead to the conclusion that designating each group of equipment components in a process unit as an affected facility would lead to adverse impacts. Therefore, EPA selected the group of equipment components within a process unit as the affected facility for fugitive emission sources other than compressors.

Relatively few compressors are located in petroleum refinery process units; in fact, may process units do not contain compressors. When a compressor is used in a process unit, it is designed for use only within that process unit. In general, there are no spare compressors in petroleum refineries, and compressors that are in place are readily identifiable. Thus, it would not be costly for an owner or operator to keep track of compressors covered by the standards and compressors not covered by the standards. EPA considered the relevant statutory factors before selecting the alternative as the basis for defining the affected facility for compressors located at petroleum refineries. Based on these considerations, EPA selected the equipment component as the affected facility for compressors.

Even though all new compressors can be designed to use the control technology described in Chapter 4 of the BID, a few existing compressors are not designed to allow reasonable retrofitting of this control technology. A few existing reciprocating compressors cannot be retrofitted with this control technology without completely replacing the distance piece or, in some cases, completely replacing the compressor. The cost of replacing a distance piece or compressor in order to bring an existing reciprocating compressor into compliance with the proposed standards would be exorbitant.

It is unlikely that any existing compressors would be covered by the standards through the modification provisions of 40 CFR 60.14 because increases in fugitive emissions from a compressor are unlikely. However, some existing compressors would be covered by the standards through the reconstruction provisions of 40 CFR 60.15. Since each compressor would be an affected facility, EPA would make a determination that it is technically or economically feasible for an existing reciprocating compressor to meet the standards [see 40 CFR 60.15(e)] before the compressor would be covered through the reconstruction provisions. This determination could be used to exempt the few existing reciprocating compressors which are not designed to allow reasonable retrofitting of the control technology described in Chapter 4 of the BID. If compressors were included among other fugitive emission sources in defining affected facilities, then an existing compressor could become subject to the standards under the modification provisions and an independent determination would not be used to consider whether an existing reciprocating compressor can be reasonably retrofitted with the control technology. These considerations support the selection of the equipment component as the affected facility for compressors.

In summary, the proposed standards apply to two types of affected facilities. Each refinery compressor in VOC service is one type of affected facility. The second type of affected facility comprises all fugitive emission sources in VOC service, other than compressors, within a refinery process unit. A process unit is defined as equipment components assembled to perform any of the physical and chemical operations within a petroleum refinery. More specifically, a process unit has discrete boundaries that consist of the points where process fluid is discharged from the preceding refining activity and where the physically or chemically treated process fluid is discharged for storage or further refining. For example, a crude oil atmospheric distillation unit is a process unit because crude oil enters the unit's column through the crude oil desalter and the preheater furnace and then the fractions separated by the column are discharged through several pipelines for further refining by other process units. There may be several columns associated with one process unit. For example, a prefractionation column may be used to separate light gasoline from the crude oil before the crude oil is separated into heavy naphtha, kerosene, and heavy gasoline. If a vacuum distillation column is employed to refine the heaviest fractions (bottoms) from the atmospheric distillation column, the vacuum distillation column is a separate process unit consisting of all equipment between the atmospheric distillation column bottoms discharge and vacuum distillation column discharge points. Other examples of petroleum refinery process units include, but are not limited to, equipment comprising fluid catalytic cracking units, storage vessels, and coking units. Thus, the process unit is used as the basis for defining an affected facility, but coverage is limited to fugitive emission sources. In addition the proposed standards would exempt additions made for process improvements if they are made without incurring a "capital expenditure" as defined in the General Provisions. Exemptions are made for routine replacement and for additions made to increase production rate if they can be accomplished without capital expenditures. There are many specific reasons for routine additions and changes made in a process unit. For example, a small number of fugitive emission sources might be added in making changes to increase productivity, to increase ease of maintenance, to improve plant safety, and to correct minor design flaws.

Sources covered by the standards of performance for VOC fugitive emission sources within the synthetic organic chemical manufacturing industry, the standard for benzene fugitive emission sources, and standards of performance being developed for fugitive emission sources within natural gas processing plants would be excluded from these standards.

Control Techniques for Fugitive Emission Sources

There are basically two types of control techniques available for fugitive emission sources: (1) Leak detection and repair programs and (2) equipment, design, and operational requirements. Leak detection and repair programs reduce fugitive emissions of VOC by establishing a procedure which includes monitoring fugitive emission sources to detect those that leak VOC's and steps to repair leaking fugitive emission sources. Both types of control techniques apply to pressure relief devices, valves in gas/vapor and light liquid service, and pumps. Equipment, design, and operational requirements apply to open-ended valves, compressors, and sampling connection systems. The control techniques considered for each fugitive emission source covered by the proposed standards are summarized below and

are described more fully in Chapter 4 of the BID.

VOC emission reduction and control cost of some fugitive emission source leak detection and repair programs were determined using the leak detection and repair (LDAR) model. The LDAR model is an empirical model developed for estimating the fraction of fugitive emission sources screened for leaks during each selected monitoring interval, the fraction of sources repaired each period, and the emission reduction efficiency of each leak detection and repair program. Detailed information required for LDAR model input is available for valves and pumps. However, because detailed LDAR model data input are not available for pressure relief devices, engineering judgment along with the LDAR model were used to determine the impacts associated with leak detection and repair programs for pressure relief devices. The LDAR model and LDAR model impact analyses are discussed in detail in Appendix F of the BID.

Based on emission reductions and control costs as estimated in the BID, control costs per megagram of VOC emission reductions were calculated. These estimates are presented in Table 1 for each control technique for fugitive emission sources covered by the proposed standards.

Pressure Relief Devices. Fugitive emissions of VOC from pressure relief devices result from leakage of process materials through the pressure relief device valve seat. VOC emissions can be controlled by a leak detection and repair program or by installation of a rupture disc between the process stream and pressure relief device.

The annualized costs and VOC emissions reductions achieved for a quarterly leak detection and repair program and for use of control equipment (rupture discs) were determined for pressure relief devices. A quarterly leak detection and repair program is less expensive than using rupture discs. However, rupture discs achieve a higher degree of fugitive VOC emission control. The control costs per megagram of VOC reduced and the emission reductions achieved are presented in Table 1.

Table 1.—Control Costs Per Megagram of VOC's Reduced[a]

Fugitive emission source	Control technique[b]	Emission reduction (mg/yr)[c]	Average[d] $/mg	Incremental[e] $/mg
Pressure relief devices	Quarterly leak detection and repair	4.4	[f](170)	[f](170)
	Rupture discs[g]	9.8	440	930
Compressors	*Controlled degassing vents*[g]	16.5	160	160
Open-ended valves	*Caps on open ends*[g]	2.8	460	460
Sampling connection systems	*Closed purge sampling*[g]	2.6	810	810
Valves	Quarterly leak detection and repair	31.7	[f](90)	[f](90)
	Monthly leak detection and repair[g]	37.1	[f](40)	300
	Sealed bellows valves	110.0	4,500	6,790
Pumps	Annual leak detection and repair	3.0	3,480	3,480
	Monthly leak detection and repair[g]	11.5	960	80
	Dual mechanical seal systems	13.9	2,200	8,200

[a] Costs and emission reductions based on fugitve emission source (component) counts in Model Unit B from the BID, EPA-450/3-81-015a, page 6-3.
[b] Further discussion of control techniques used can be found in Chapters 4 and 6 of the BID.
[c] Emission reductions are for Model Unit B. Refer to BID Tables 3-1, 7-1, and F-14.
[d] Average dollars per megagram (cost effectiveness) = net annualized cost per component ÷ annual VOC emission reduction per component.
[e] Incremental dollars per megagram = (net annualized cost of the control technique − net annualized cost of the next less restrictive control technique) ÷ (annual emission reduction of control technique − annual emission reduction of the next less restrictive control technique).
[f] Values in parentheses denote savings.
[g] Control techniques selected as the basis for the proposed standards are italicized.

Compressors. Packed seals, mechanical seals, or liquid film seals are used to limit leakage of process gases around compressor drive shafts. These seals can emit VOC as a result of seal deterioration or imperfections. VOC also can be emitted from barrier fluid degassing vents that are used on some types of dual mechanical seals. Fugitive emissions of VOC from compressor seals can be controlled by venting the leakage to an air pollution control device (controlled degassing vents). The annualized costs and emission reductions associated with venting the leakage to an air pollution control device results in control costs per megagram of VOC reduced and emission reductions as presented in Table 1.

Open-Ended Valves and Sampling Connection Systems. Fugitive emissions of VOC result from leakage of process fluids around open-ended valves in the shut position or around incompletely closed open-ended valves. These emissions can be controlled by the installation of a cap or a second valve. Fugitive emissions of VOC arise when process fluids are purged from sampling lines. These emissions can be reduced through the use of closed sampling systems. The control costs per megagram of VOC reduced and the emission reductions achieved are presented in Table 1.

Valves. Fugitive emissions of VOC result when valve packings or O-rings that are used to limit leakage of process fluids around valve stems deteriorate. VOC emissions from valves can be reduced through leak detection and repair programs or the use of sealed bellows valves.

The annualized costs per megagram of VOC emissions reduced and emission reductions achieved were determined for leak detection and repair programs and the use of sealed bellows valves. These costs and emission reductions are presented in Table 1. Quarterly monitoring for leaks from valves in gas/vapor and in light liquid service results in savings. Monthly leak detection and repair of valves in gas/vapor and light liquid service increases the degree of emission reduction while maintaining the savings; however, the magnitude of these savings are less than the savings obtained for a quarterly leak detection and repair program. Sealed bellows valves provide the highest degree of VOC control; however, the control cost per megagram of VOC reduced is substantially greater than the costs for any of the leak detection and repair programs.

Pumps. Fugitive emissions of VOC result from leakage of process fluids around pump drive shafts and through deteriorated seal packings or worn mechanical seal faces. VOC can also be emitted from the barrier fluid degassing vents used on some types of dual mechanical seal systems. VOC emissions from pump seals can be reduced through leak detection and repair programs or through the use of dual mechanical seals with controlled degassing vents.

The control costs incurred for each megagram of VOC emissions reduced and emission reductions achieved were determined for leak detection and repair programs and the use of dual mechanical seals with controlled degassing vents. These costs and emission reductions are presented in Table 1. Dual mechanical seals with controlled degassing vents provide the greatest amount of VOC emission reduction; however, the control cost per megagram of VOC reduced is greater than that for either leak detection and repair program.

Selection of the Basis for the Proposed Standards

Section 111 of the Clean Air Act, as amended, requires that standards of performance be based on the best system of continuous emission reduction that has been adequately demonstrated, considering costs, nonair quality health and environmental impact and energy requirements (best demonstrated technology). As a first step toward determining which control techniques should be selected as the basis of the proposed standards, EPA analyzed the annualized cost of controlling VOC emissions and the resultant VOC reduction for each alternative control technique. EPA also considered the nonair environmental, energy, and economic impacts associated with selectifg alternative control techniques as the basis for the proposed standards.

The control costs per megagram of VOC reduced are presented in Table 1. These costs do not represent the actual amounts of money spent at any particular plant site. The cost of VOC emission reduction systems will vary according to the petroleum product being produced, production equipment, plant layout, geographic location, and company preferences and policies. However, these costs are considered typical of control techniques for fugitive emission sources within petroleum refineries and can be used in making decisions about the level of control to be required.

After review of control costs per megagram of VOC reduced, EPA judged that the cost of certain control equipment on fugitive emission sources is unreasonably high. The analysis presented in Table 1 shows that leakless equipment on valves in gas/vapor and light liquid service have incremental control costs per megagram of VOC reduced that are about $6,800. The analysis also shows that dual mechanical seal systems on pumps have an incremental control cost per megagram of VOC reduced of about $8,200. After examining these costs and resulting emission reductions, EPA determined the control costs per megagram of VOC reduced for leakless equipment on valves and dual mechanical seal systems on pumps to be unreasonably high.

EPA decided that a leak detection and repair program with monthly monitoring for pumps and valves and the use of control equipment for pressure relief devices, open-ended valves, sampling connection systems, and compressors have reasonable control costs per megagram of VOC reduced. These control techniques are italicized in Table 1. The incremental control costs per megagram of VOC reduced for these control techniques range from a cost of $80 to a cost of about $900 and are considered reasonable. Petroleum refineries are large emitters of VOC with fugitive emission sources comprising a significant VOC emitting segment in petroleum refineries. These control techniques would result in a nationwide reduction of at least 31,000 Mg of VOC in the fifth year after proposal. It is reasonable to expect that a reduction of this size in VOC emissions from the petroleum refining industry would be of significant benefit to the environment. After considering the results of the analysis of the control costs per megagram reduced by these control techniques, EPA tentatively selected them as the basis for the proposed standards. Economic, energy, and nonair quality environmental impacts were then examined to determine if they would alter this selection of control techniques.

In considering the potential economic impacts of the control techniques, EPA examined regulatory alternatives that included six combinations of the control techniques for fugitive emission sources. That is, each regulatory alternative included one of the control techniques considered for each fugitive emission source. For example, Regulatory Alternative V included rupture discs on pressure relief devices, controlled degassing vents on compressor seals, caps on open-ended valves, closed purged sampling for sampling connection systems, monthly leak detection and repair programs for valves in gas/vapor and light liquid service, and dual mechanical seal systems on pumps. Regulatory Alternative VI was the most costly and had the greatest emission reducton. The regulatory alternatives are described in detail in Chapter 6 of the BID; the economic impacts of the regulatory alternatives are discussed in Chapter 9 and Appendix F of the BID.

The economic analysis shows that the only regulatory alternative which could cause a significant adverse economic impact on petroleum refineries included the use of leakless equipment on valves (Alternative VI). The analysis shows that any combination of the control techniques presented in Table 1, excluding the use of leakless equipment on valves, would not have a significant adverse economic impact on petroleum refineries. The analysis shows that the control techniques for which it was decided the costs per megagram of VOC reduced are reasonable would result in no adverse impact on profitability (decrease less than 0.5 percent), would have a potential to slightly increase the consumer price of petroleum products (0.1 percent or less), and would have no adverse impact on capital availability for construction of petroleum refineries. Since consideration of costs per megagram of emission reduction eliminated the only control technique which could have contributed to an adverse economic impact, consideration of economic factors played no further role in the selection of the basis of the proposed standards.

EPA also examined the nonair quality environmental and energy impacts of the control techniques considered for each source. Analysis of these impacts for the various regulatory alternatives are presented in Chapter 7 and Appendix F of the BID. There were no significant adverse impacts identified; therefore, the nonair quality environmental and energy impacts did not affect the decision on the basis of the proposed standards.

In summary, the most effective control techniques which were considered to have reasonable costs per megagram of VOC emissions reduced were selected as the basis of the proposed standards.

These control techniques include a monthly leak detection and repair program for pumps and valves, and control equipment for pressure relief devices, open-ended valves, sampling connection systems, and compressors. Less restrictive control techniques were not considered further because they achieved less emission reduction, and there were no cost, economic, energy, or nonair quality environmental impacts which necessitated further examination of these control techniques.

Selection of Format for the Proposed Standards

Several formats could be used to implement the control requirements selected as the basis for the proposed standards. Section 111 of the Clean Air Act requires that a standard of

performance be prescribed unless, in the judgment of the Administrator, it is not feasible to prescribe or enforce such a standard. Section 111(h) defines two conditions under which it is not feasible to prescribe or enforce a performance standard. These conditions are: (1) If the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations, or (2) if the pollutants cannot be emitted through a conveyance device. If a performance standard is not feasible to prescribe or enforce, then the Administrator may instead promulgate a design, equipment, work practice, or operational standard or combination thereof.

A performance standard allows for some flexibility because any control technique may be used if it achieves the level of emission reduction represented by the standard. However, for most refinery fugitive emission sources, it is not feasible to prescribe a performance standard. One approach to prescribing a performance standard is to limit emissions directly. Except in those cases in which standards can be set at "no detectable emissions," the only way to measure emissions from refinery fugitive emission sources, such as pumps and valves, would be to use a bagging technique for each of the sources in a process unit. The great number of sources and their dispersion over large areas would make such a requirement economically impracticable. Therefore, EPA has not selected this type of performance standard format in prescribing the proposed standards.

Another approach for prescribing a performance standard would be to specify a number or percent of fugitive emission sources that would be allowed to leak. This approach would be more qualitative than an approach based on quantitative emission measurements such as bagging. This format would be based on a leak frequency limit rather than an emission limit and would have some of the same benefits of flexibility. The only fugitive emission source for which a leak frequency limit would be applicable is valves because other fugitive emissions are too few in number to allow a meaningful percent to be determined. But, the variability in the percentage of valves leaking among process units and the resulting correlation to emissions precludes setting an allowable percentage of valves leaking that could be achieved by all process units within the refining industry. This variability is observed even among units in which leak detection and repair programs are being implemented. Therefore, establishing an allowable percentage of leaking valves is not practicable.

However, establishing an allowable percentage of valves leaking based on cost considerations and levels of performance is possible. If a process achieves this level of good performance, then the owner or operator may elect for the valves to comply with an alternative standard for valves. Because this approach would add flexibility to the proposed standards, the proposed standards incorporate this approach. This is discussed in more depth in *Alternative Standards for Valves* in the next section of this preamble.

Based on EPA's determination that it is infeasible to prescribe a performance standard for most fugitive sources at refineries, the alternative regulatory formats identified in Section 111(h) were considered. One possible format is an equipment standard. Equipment standards provide well-documented emission reductions. Determining compliance would require an initial check to ensure that the equipment had been installed properly and periodic checks to ensure that the equipment was continuing to operate properly. An inherent disadvantage associated with this type of format is less site-specific flexibility.

In the next section of this preamble, EPA considers emission reductions associated with equipment other than the equipment selected as the basis for the proposed standards. As a consequence, EPA is proposing to allow certain equipment as alternatives to the equipment and work practices required by the proposed standards. Alternative equipment is allowed if it provides a reduction in emissions that is at least equivalent to the reductions achieved by the equipment or work practices required by the proposed standards. In addition, owners and operators of affected facilities would have additional flexibility because they could obtain EPA's approval to employ other equivalent techniques under Section 111(h)(3) and innovative techniques under the waiver provisions of Section 111(j).

Another format is work practices. An example of this format would be a program for leak detection and repair. Inspection methods, inspection time intervals, and time allowed for repair would be defined in detailing the work practices. Compliance with a work practice standard would be determined by judging success in implementing the work practices. Recordkeeping would be needed to serve as the basis for judging this success.

Design and operational standards are other possible formats. Rather than requiring specific control equipment or work practices, a design or operational format would require that a certain design representative of a level of control be attained or that certain procedures be followed during operation of a process. For example, combustion devices may be required to be designed to achieve a specified level of control efficiency.

The proposed standards could incorporate all of the possible formats. Different formats are required for different fugitive emission sources because characteristics of the emission sources, and the available emission control techniques, and the applicability of the measurement method used for fugitive emission sources differ among the sources. In the next section, the rationale for selecting a particular format is explained for each type of fugitive emission source. For each fugitive emission source, the feasibility of prescribing or enforcing a performance standard is discussed. If a performance standard is not feasible, the rationale for selecting another format is presented.

Selection of Emission Limit, Equipment, Work Practice, Design and Operational Standards

Pressure relief devices. Rupture disks were selected as the basis for the proposed standards for gas service pressure relief devices. When the integrity of rupture disks is maintained, fugitive emissions of VOC through the relief device are eliminated. Rupture disks maintain their integrity unless an overpressure occurs. After the occurrence of an overpressure, replacement of the rupture disk once again eliminates fugitive emissions of VOC through the pressure relief device.

For control techniques that eliminate fugitive emissions, an emission limit measurement for "no detectable emissions" is feasible. An instrument reading of less than 500 parts per million by volume (ppmv) above a background concentration based on Reference Method 21 can be used to indicate whether fugitive emissions have been eliminated, that is, have "no detectable emissions." Measurement methods for determining the quantitative emission rate from pressure relief devices are not feasible because they would require bagging each piece of equipment. However, as discussed in Appendix D of the BID, Reference Method 21 does not allow quantitative measurement of emissions, but it does allow the detection of leaks of fugitive VOC

emissions from relief devices. Therefore, the proposed standard for relief devices in gas service is "no detectable emissions."

The "no detectable emission" limit would not apply to discharges through the pressure relief device during overpressure relief because the function of relief devices is to discharge process fluid, thereby reducing dangerous high pressures within the equipment. The standard would specify, however, that the relief device be returned to a state of no detectable emissions within 5 days after such a discharge. The standard would further require an annual test to verify the "no detectable emissions" status of the pressure relief devices.

A test to determine if a fugitive emission source is complying with a "no detectable emissions" requirement is a performance test. As provided in 40 CFR 60.8(f) performance tests require three separate runs, unless otherwise specified in an applicable subpart. A test to determine if a fugitive emission source is complying with a "no detectable emissions" requirement does not need three runs. Thus, performance tests to determine "no detectable emissions" would be exempted from 40 CFR 60.8(f) by the proposed standards.

Performance test requirements under 40 CFR 60.8(d) include a notification to the Administrator 30 days before each performance test. For fugitive emission sources, tests to determine "no detectable emissions" may occur throughout a year and must occur after each overpressure relief. Requiring an owner or operator to notify the Administrator as provided in 40 CFR 60.8(d) is not considered reasonable for these proposed standards. Thus, to reduce the reporting burden on industry, owners or operators of affected facilities are exempted from 40 CFR 60.8(d) by the proposed standards.

As an alternative to the use of rupture disks and other techniques that achieve the "no detectable emission" limit, EPA is proposing to allow owners or operators to vent pressure relief devices to control devices achieving the requirements presented in the *Closed vent systems and control device* portion of this section of the preamble. When venting a pressure relief device, the control device also reduces emissions of VOC that occur during overpressure relief. EPA judges that the emission reduction lost by allowing 95 percent control for fugitive emissions (rather than 100 percent control achieved by the "no detectable emission" limit) is offset by the emission reduction gained by controlling the emissions due to overpressure relief. Thus, EPA is proposing to allow the use of closed vent systems connected to a control device as an equivalent alternative to the "no detectable emission" limit.

Leakless equipment. The proposed standards would not require leakless equipment, such as sealed-bellows and diaphragm valves, canned and diaphragm pumps, and sealless compressors. This equipment is either not widely applicable to refineries, or as indicated in Table 1, the control costs per megagram of emission reduction achieved are unreasonable. However, use of leakless equipment is clearly equivalent to the proposed standards for pumps, compressors, and valves. The proposed standards would allow the use of such equipment as an alternative to the required practices.

Leakless equipment would be required to operate with "no detectable emissions" at all times when this equipment is in service. As with pressure relief devices, a performance test for "no detectable emissions" means an instrument reading of less than 500 ppmv or above a background concentration based on the measurement method of Reference Method 21. The proposed standards require that the leakless status of this equipment be verified annually and at other times if requested by EPA. In addition, the proposed standards would exempt these performance tests from 40 CFR 60.8(d) and 60.8(f) of the General Provisions.

Compressors. The basis of the proposed standards for compressors is mechanical seals with barrier fluid systems and controlled degassing vents. Emission limits for compressors have not been proposed because the application of available measurement methods would not be practicable because of technological or economic limitations. That is, bagging of compressors for emission measurement would be unreasonably expensive and impractical. Thus, EPA selected mechanical seals with barrier fluid systems and controlled degassing vents as the required equipment for compressors. The controlled degassing vents would use a closed vent system and a control device and, therefore, would be required to comply with the requirements discussed in the *Closed vent systems and control devices* portion of this section of the preamble.

EPA reviewed enclosure of the compressor seal area as an alternative to requiring seals with barrier fluid systems. If an enclosure captures all emissions from the compressor seal area, then the fugitive emissions can be captured and transported effectively to a control device by a closed vent system. The level of emission reduction achieved by this alternative is at least equivalent to the level of reduction attained by compressors that are fitted with the equipment that was selected as the basis for the proposed standards. Therefore, EPA proposes to allow enclosure of the compressor seal area and venting of fugitive emissions through a closed vent system to a control device, provided the enclosure captures all the emissions from the seal area. The closed vent system and control device would be required to comply with requirements discussed in the *Closed vent systems and control devices* portion of this section of the preamble.

Section 111(h) of the Clean Air Act requires that when equipment standards are established, requirements must also be established to ensure the proper operation and maintenance of the equipment. A pressure or level indicator on the fluid system would reveal any catastrophic failure of the seal or of the barrier fluid system. This indicator could be monitored in the control room or be equipped with an alarm to signal a failure of the system. Thus, a requirement to include an indicator to detect failure of the system is proposed to ensure the proper operation and maintenance of the mechanical seal system.

As mentioned in the *Selection of Affected Facilities* section of this preamble, there may be some cases in which seals with barrier fluid systems can not be utilized because some existing compressors can not technologically or economically be retrofitted with dual seals and barrier fluid systems. For example, use of a dual seal with barrier fluid or its equivalent could require replacement of the distance piece on a reciprocating compressor or replacement of an entire reciprocating compressor. In these situations, determination of whether installation of a dual seal and barrier fluid system or its equivalent is technologically or economically feasible can take place during the determination of whether an existing compressor will be considered reconstructed and therefore affected by the standards. If EPA determines that an existing compressor can not be technologically or economically retrofitted, then the compressor would not be required to comply with the standards.

Open-Ended Valves. The basis of the proposed standards is equipment that would effect enclosure of the open end. Open-ended valves are not designed to release fugitive emissions to a conveyance, and bagging of these sources for emission measurement

would not be economically or technologically practicable. A "no detectable emissions" standard could not be selected as the format for the proposed standard because VOC could leak through the valve seat and become trapped in the line between the open-ended valve and the enclosure. The trapped VOC could be emitted to atmosphere, even though the VOC emitted to atmosphere would be much less than the VOC emitted without the enclosure. Thus, EPA selected the use of an equipment standard for control of fugitive emissions from open-ended valves.

Enclosure of the open end can be achieved by installing a cap, plug, or a second valve. The control efficiency associated with these techniques is approximately 100 percent, except when the line is used for draining, venting, or sampling operations. Thus, EPA is proposing standards that require open-ended valves to be equipped with a cap, plug, or a second valve. If a second valve is used, the proposed standards require the upstream valve to be closed first. After the upstream valve is completely closed, the downstream valve must be closed. This operational requirement is necessary in order to prevent trapping process fluid between the two halves, which could result in a situation equivalent to the uncontrolled open-ended valve.

Sampling connection systems. Closed-purge sampling was selected as the basis for the standards for sampling connection systems. Closed-purge sampling connection systems eliminate emissions due to purging by either returning the purge material directly to the process or by collecting the purge in a collection system which is not open to the atmosphere. Generally, these sampling connection systems are not designed to release fugitive emissions to a conveyance, and bagging of these sources for emission measurement would not be economically or technologically practicable. Although closed-purge sampling effectively eliminates emissions due to purging, a "no detectable emissions" limit could not be prescribed because closed-purge systems can have detectable emissions. Thus, EPA selected closed-purge sampling as the equipment requirement for sampling connection systems.

In addition to closed-purge sampling, EPA considered closed-vent vacuum systems connected to a control device and *in-situ* sampling systems. Closed-vent vacuum systems that are connected to a control device extract the sample purge and then reduce emissions from the sample purge by transporting the VOC to the control device. *In-situ* sampling systems involve measurement or sampling of process stream conditions without extraction of the sample from the process stream. *In-situ* sampling systems, therefore, result in no emissions of VOC. If closed-vent vacuum systems are not open to the atmosphere and the control device complies with the requirements discussed in the *Closed vent systems and control devices* portion of this section of the preamble, then their reduction of VOC emissions would be equivalent to the reduction achieved by closed-purge sampling connection systems. Based on these considerations, EPA is proposing to allow closed-vent vacuum systems connected to control devices and *in-situ* sampling systems as allowable alternatives to closed-purge sampling.

Valves. Valves are generally not designed to release fugitive emissions to a conveyance, because of the large number of valves, bagging of these sources for emission measurement would not be economically or technologically practicable. As discussed in the *Selection of Format for the Proposed Standards* section of this preamble, an allowable percentage of valves leaking can not be prescribed because of process unit variability. A "no detectable emissions" limit can not be prescribed, because, with the control techniques selected as the basis for the proposed standards, valves will still occasionally leak.

Work practices consisting of periodic leak detection and repair programs were selected as the basis for the proposed standards for valves. Several factors influence the level of emission reduction that can be achieved by a leak detection and repair program. The three main factors are the monitoring interval, leak definition, and repair interval. Training and diligence of personnel conducting the program, the adequacy of repair methods attempted, and other site-specific factors may also influence the level of emission reduction achievable; however, these factors are less quantifiable. The overall emission reduction of a leak detection and repair program depends on the three main factors. Each of these three factors limits the effectiveness of the program. For example, if each of the factors selected for a leak detection and repair program represents a 90 percent effectiveness, then the overall effectiveness would be about 73 percent. Thus, the most effective definition that is reasonable for each factor should be selected.

The *monitoring interval* is the frequency at which individual component monitoring is conducted. The length of time between inspections is best determined by the rate at which new leaks occur and repaired leaks recur. More frequent inspections could then be required for sources which tend to leak more often. Available data indicate that leak recurrence is an important factor in predicting leaks from valves. That is, if a valve leaks, then it is more likely to leak than a valve that has not leaked. However, these data also show that some valves leak less frequently than others. EPA considers the annualized cost of monthly monitoring of valves that leak infrequently to be unreasonably high in comparison to the annualized cost of quarterly monitoring, considering the emission reduction achieved by monthly and quarterly monitoring. However, EPA does not consider the annualized cost of monthly monitoring of valves that leak frequently to be unreasonably high considering the emission reduction achieved by monthly monitoring of these valves. Thus, EPA is proposing that leak detection and repair programs include monthly monitoring for valves, except that quarterly monitoring would be allowed for valves which have been found not to leak for two successive months (monthly/quarterly monitoring).

Some valves are difficult to monitor because access to the valve is restricted. Difficult-to-monitor valves can be eliminated in new facilities but cannot be eliminated in existing facilities. Therefore, for facilities that become affected by a modification or reconstruction, EPA is proposing an annual leak detection and repair program for valves which are difficult to monitor. However, for new affected facilities, all valves would be subject to the proposed monthly leak detection and repair program. Valves which are difficult to monitor are defined as valves which would require elevating the monitoring personnel more than two meters above any readily available support surface. This means that ladders must be used, if needed, to elevate monitoring personnel.

In addition to valves that are difficult to monitor, some valves are unsafe to monitor because monitoring personnel would be subjected to imminent hazards. Valves which are unsafe to monitor cannot be eliminated in new or existing facilities. The proposed standards would allow an owner or operator with valves that are unsafe to monitor to develop a special leak detection and repair program. These special programs would conform with

the routine monitoring requirements of the proposed standards as much as possible, but would allow deviation from a routine monitoring so that monitoring would not occur under unsafe conditions. Valves which are unsafe to monitor are defined as those valves which could, based on the judgment of the owner or operator, expose monitoring personnel to imminent hazards from temperature, pressure, or explosive process conditions.

The *leak definition* is the instrument reading observed during monitoring that defines which sources require repair. As discussed in Appendix D of the BID, the proposed standards would require monitoring to follow Reference Method 21. The best leak definition would be the one that achieves the most emission reduction at reasonable costs. The emission reduction achieved would increase as the leak definition decreased, due to the increasing number of sources that would be found leaking and, therefore, repaired. As a matter of practical consideration, most commonly available hydrocarbon detectors that are considered intrinsically safe have a maximum reading of 10,000 ppm. A leak definition higher than 10,000 ppm, such as 20,000 ppm, could be selected (dilution probes could be used with the portable detectors); however, there would be less emission reduction than with the 10,000 ppm definition and no substantial associated cost savings. Consequently, there was no basis for selecting a leak definition greater than 10,000 ppm. A leak definition lower than 10,000 ppm may be practicable in the sense that leaks can be repaired to levels less than 10,000 ppm. However, EPA is unable to conclude that a leak definition lower than 10,000 ppm is practicable. Because the 10,000 ppm leak definition would achieve emission reductions at reasonable costs and safe available hydrocarbon detectors can accurately read 10,000 ppm, the 10,000 ppm number was selected as the leak definition for valves. This definition was also considered appropriate for pumps. The same portable monitor used for valves would be used for pumps, and consideration of other relevent factors did not indicate that the 10,000 ppm definition should be different for these sources.

The *repair interval* is the length of time allowed between the detection of a leaking source and repair of the source. To provide the maximum effectiveness of the leak detection and repair program, the repair interval should be selected to require expeditious reduction of emissions but allow the owner or operator sufficient time to maintain flexibility in the refinery's overall maintenance schedule.

The length of the repair interval would affect emission reductions achievable by the leak detection and repair program, because leaking sources would be allowed to continue to leak for a given length of time. Repair intervals of 1, 5, 10, 15, 30, and 45 days were evaluated. The effect on the emission reduction potential is proportional to the number of days the source is allowed to leak between detection and repair.

A repair interval of one day could cause severe problems in coordinating activities of personnel involved in leak detection and leak repair, and in some instances would not be technically feasible. A repair interval of one day would essentially require repair of each component as soon as the leak was discovered. Even though some owners or operators may have repair personnel assigned to the leak detection team, only simple field repair could normally be attempted within 1 day.

An initial attempt at repair of a leaking source should be accomplished as soon as practicable after detection of the leak. Most repairs can be done quickly. A 5-day period provides sufficient time to schedule simple field repair. Attempting to repair the leak within 5 days will help maintenance personnel to identify the leaks that can not be repaired with simple field repair or without shutdown of the affected facility.

Valves that are not repairable by simple field repair may require removal from the process for repair. Even repair intervals of 5 and 10 days could cause scheduling problems is repairing these valves. A 15-day interval provides time for isolating pieces of leaking equipment when equipment isolation is needed for repair beyond simple field repairs. A 15-day interval provides the owner or operator with sufficient time for determining precisely which spare parts are needed and provides sufficient time for flexibility in scheduling repair for these valves. In addition, a 15-day interval provides time for better determination of methods for isolating pieces of leaking equipment when equipment isolation is needed for repair beyond simple field repairs.

In general, a 5-day repair interval provides sufficient time to schedule simple field repair. A 15-day repair interval allows more efficient handling of more complex repair tasks while maintaining an effective reduction in fugitive emissions. A repair interval of 30 or 45 days provides less effective reduction in emissions and does not substantially improve the efficiency in handling repair tasks. Thus, the proposed standards require an initial attempt to repair a leaking valve within 5 days and complete repair, except as discussed below, within 15 days.

Delay of repair beyond 15 days would be allowed for leaks that could not be repaired without shutting down an affected facility. In general, these leaks would have to be repaired at the next scheduled facility shutdown. Spare parts for valves can usually be stocked such that all leaks that could not be repaired without shutting down the affected facility could be repaired during the shutdown. Spare parts include packing gland bolts and valve packing material. In a few instances, replacement of the entire valve assembly would be required. EPA is proposing to allow delay of repair beyond an affected facility shutdown for valves which require replacement of the entire valve assembly, provided the owner or operator can demonstrate that sufficient stock of spare valve assemblies had been maintained before the stock had been depleted.

Alternative Standards for Valves. The emission reduction and annualized cost of the proposed leak detection and repair program depend in part on the number of leaking valves that are detected during monitoring. If very few valve leaks are detected in an affected facility, then the amount of VOC that could be reduced by the proposed program for valves is much smaller than the amount that could be reduced in a facility having more leaks. Additionally, the annualized cost of the leak detection and repair program would be larger for an affected facility with fewer leaks than in an affected facility with more leaks, because the annualized cost includes a recovery credit based on the amount of VOC reduced by the program. Thus, the annualized cost per megagram of VOC emission reduction for the proposed leak detection and repair program varies with the number of valves which leak within an affected facility.

For example, a monthly leak detection and repair program for valves in light liquid service and valves in gas/vapor service results in an annualized credit of about $2,100 and achieves an annual emission reduction of 36.6 Mg for a typical small refinery process unit. In contrast, for a small process unit with 2.0 percent of the valves leaking on the average, a monthly leak detection and repair program results in an annualized cost of $3,500 and achieves an annual emission reduction of 4.9 Mg. For a small process unit with 0.5 percent of

the valves leaking on the average, a monthly leak detection and repair program results in an annualized cost of $4,200 and achieves an annual emission reduction of about 0.4 Mg.

There is no precise breakpoint in the annualized cost and emission reduction relationship. However, EPA judges that the emission reduction and annualized cost relationship is unreasonably high for process units having on the average fewer than 1.0 percent of valves leaking. Based on this judgment, an allowable percent of valves leaking was determined that reflects the average of 1.0 percent of valves leaking, as discussed below.

An allowable percent of valves leaking was selected that included the variability inherent in leak detection of valves. The variability in leak detection of valves can be characterized as a binominal distribution around the average percent of valves leaking. Inclusion of the variability in leak detection of valves is accomplished by straightforward statistical techniques based on the binominal distribution. An allowable percent of valves leaking of 2.0 percent, to be achieved at any point in time, would provide an owner or operator a risk of about 5 percent that greater than 2.0 percent of valves would be determined leaking when the average of 1.0 percent was actually being achieved. Based on these considerations, EPA considers an allowable percent of valves leaking of 2.0 percent to represent an average of 1.0 percent of valves leaking.

EPA is proposing two alternative standards which would exempt valves within process units from the required (monthly/quarterly monitoring) leak detection and repair program. Owners or operators of affected facilities may identify and elect to achieve either of the alternative standards. The alternative standards would allow owners or operators to tailor fugitive emissions control programs to their own operations. An owner or operator would report which alternative standard he or she had identified and elected to achieve.

The first alternative standard would limit the maximum percent of valves leaking within an affected facility to 2.0 percent. This type of standard would provide the flexibility of a performance standard. As previously pointed out in the *Selection of Format for the Proposed Standards* section of this preamble, an industry-wide performance standard which could be achieved at all facilities was not possible for valves. This was due to the variability in valve leak frequency and variability in the ability of a leak detection and repair program to reduce these leaks among all affected facilities within the industry. However, this alternative standard would allow any affected facility the option of complying with an allowable percent of valves leaking for a particular affected facility. Choosing this alternative standard would allow for the possibility of different leak detection and repair programs and substitution of engineering controls at the discretion of the owner or operator. This alternative standard would also eliminate a large part of the recordkeeping associated with the monthly/quarterly leak detection and repair program for valves.

Performance tests as specified in 40 CFR 60.8(f) require three runs. Three runs for performance tests to determine the percent of valves leaking are unnecessary. Thus, performance tests are exempt from § 60.8(f) in the proposed standards. However, this alternative standard would require a minimum of one performance test per year. Additional performance tests could be requested by EPA. If the results of a performance test showed that greater than 2.0 percent of the valves leak, the owner or operator could be cited for violation of the standards.

In certain circumstances, an owner or operator may want to request a waiver of future tests as provided in the General Provisions of 40 CFR Part 60. This would provide flexibility for owners and operators of petroleum refineries where, for whatever reason, routine leak detection and repair is not needed to effectively control emissions. This would include refineries which use superior equipment either due to the value or hazardous nature of the product, refineries which have effective occupational safety and health programs, or refineries which simply do not leak for unexplained reasons. Based on performance tests that demonstrate the achievability of the 2.0 percent standard and information that indicates that this standard would be achieved on a continuing basis, EPA could waive the annual performance tests.

The second alternative standard would allow the use of skip-period leak detection for valves. Under skip-period leak detection, an owner or operator could skip from routine leak detection for valves to less frequent leak detection. This skip-period leak detection program would require that a performance level of 2.0 percent be achieved on a continuous basis with more than 95 percent certainty. An owner or operator would choose one of two skip-period leak detection programs for valves and then implement that program. The first skip-period leak detection program could be used when fewer than 2.0 percent of the valves had been leaking for two consecutive quarterly leak detection periods. The first skip-period leak detection program would allow an owner or operator to skip every other quarterly leak detection period: that is, leak detection can be performed semi-annually. Under the second skip-period leak detection program, if fewer than 2.0 percent of the valves had been leaking for five consecutive quarterly leak detection periods, the owner or operator may skip three quarterly leak detection periods; that is, leak detection can be performed annually. When more than 2.0 percent of valves are found to leak monthly/quarterly leak detection would be required to be resumed.

Pumps. As with some of the previously discussed fugitive emission sources, pumps are generally not designed to release fugitive emissions to a conveyance. Because of the difficulty of routinely bagging pumps, bagging of these sources for emission measurement would not be economically or technologically practicable. Even though Reference Method 21 can be used to detect leaks from pumps, the number of pumps and the variability in the number of pumps leaking within process units does not allow the establishment of a performance standard. A "no detectable emissions" limit can not be prescribed because, with the control technique specified as the basis for the proposed standards, pumps can still leak.

In the analysis for the basis for the proposed standards, EPA selected a work practice consisting of periodic leak detection and repair program for pumps. As with valves, the effectiveness of the leak detection and repair program for pumps is limited by the selection of the monitoring interval, leak definition, and repair interval. The same leak definition and repair interval selected for valves was selected for pumps for the reasons discussed previously. Monthly monitoring was selected as the monitoring interval for pumps based on cost considerations, as discussed in the *Selection of Basis for the Proposed Standards* section of this preamble. One month provides the most effective leak detection and repair program for pumps without imposing difficulties or unreasonable costs in implementing the program.

Delay of repair beyond 15 days would be allowed for leaks that could not be repaired without shutting down the affected facility. These leaks would have to be repaired as soon as practicable, but not later than by the end of the next facility shutdown. Spare parts are generally stocked by refineries

in order to provide expeditious repair of pump seal failures. Sufficient stocks of spare parts can be maintained to complete pump seal repair during scheduled facility shutdown without imposing an unreasonable burden on industry. Therefore, delay beyond a shutdown is not allowed.

Several types of pumps with ancillary equipment can achieve emission reductions of VOC at least equivalent to that achieved by a monthly leak detection and repair program for pumps. These include dual mechanical seal systems that utilize a barrier fluid between the seals, enclosure of the pump seal area, and sealess pumps. If the barrier fluid in a dual seal system is maintained at a pressure greater than the pump stuffing box pressure, any leakage between the seals would be from the barrier fluid to the process fluid, so no process fluid would be emitted to the atmosphere. If the pump stuffing box pressure is greater than the barrier fluid pressure (for example, tandem seals), the barrier fluid collects the leakage from the inner seal; the process fluid collected by the barrier fluid is controlled by either (1) connection the barrier fluid degassing system to a control device with a closed vent system, or (2) by returning the barrier fluid to the process stream. Because these duel mechanical seal systems are at least equivalent to a monthly leak detection and repair for pumps, they have been exempted from the monthly monitoring provisions of the proposed standards.

Section 111(h) of the Clean Air Act requires that when equipment standards, such as dual mechanical seal systems, are established, requirements must also be established to assure the proper operation and maintenance of the equipment. A pressure of level indicator on the barrier fluid system would reveal any catastrophic failure of the inner or outer seal, or of the barrier fluid system. This indicator could be monitored in the control room or equipped with an alarm to signal a failure of the system. Thus, EPA is proposing these requirements to assure the proper operation and maintenance of the dual mechanical seal system.

Sealless pumps, such as diaphragm or canned pumps, do not have a potential leak area and, therefore, are at least equivalent to monthly leak detection and repair and dual seal systems. Thus, any equipment that complies with a "no detectable emissions" limit is equivalent to the monthly leak detection and repair program required in the proposed standards. As with other leakless equipment, the proposed standard requires an initial performance test, using the procedures specified in Reference Method 21, to verify that the piece of leakless equipment meets the "no detectable emissions" limit, and annual rechecks to ensure continued operation with "no detectable emissions."

In many cases, the seal area of a pump could be completely enclosed, and this enclosed area could be connected to a control device with a closed vent system. The control efficiency of this arrangement is dependent on the control efficiency of the combustion or vapor recovery system. The closed vent system could require a flow-inducing device to transport emissions from the seal area to the control device. However, some owners or operators may decide that this approach is preferable to leak detection and repair. Enclosing the seal area and venting the captured emissions to a control device by means of a closed vent system is a reasonable alternative because this system would be at least as effective as a monthly leak detection and repair program. Therefore, the EPA is proposing to allow pumps to be equipped with enclosed seal areas that are connected to a control device by a closed vent system.

Closed vent systems and control devices. Control devices would be used to reduce VOC captured and transported through closed vent systems. These control devices would be existing and would be designed to dispose of organic vapor streams from other sources in the plant. Because the streams from the closed vent systems will usually be low-flow or intermittent in comparison to streams from other sources, emissions in closed vent streams will often contribute a very small and varying portion of the total organic vapor stream going to the control device. Measurement techniques that reflect the effectiveness of these control devices to reduce fugitive emissions of VOC are limited. Because these measurements would require elaborate and costly material balancing of the VOC entering the control devices, it is not economically practicable to measure the emissions from these control devices. For this reason an emission standard is not proposed for control devices used to reduce VOC that are captured and transported by closed vent systems.

Control devices were selected as part of the best technological system of emission reduction for some fugitive emission sources (such as compressors) and are part of alternative approaches to achieving compliance with the standards for other fugitive emission sources (such as closed-vent vacuum systems connected to a control device). These control devices would already be in place in existing refineries and therefore would not be designed solely to reduce VOC streams from fugitive emission sources. Flares are almost always present in refineries. Enclosed combustion devices and vapor recovery systems are present in most, if not all, refineries. These existing control devices provide varying degrees of emission reduction, and, therefore, selecting standards of performance for these devices may not reflect the emission reduction capability of new control devices, nor the capability of devices specifically designed for control of fugitive emission sources.

Flares are used in petroleum refineries mainly as a means of handling emergency releases of combustible material from process units within the refinery. Flares also can be used in petroleum refineries to combust certain waste gas streams that might otherwise pose a safety problem if allowed to vent uncontrolled into the ambient air. EPA has examined recent flare studies in an effort to select a representative destruction efficiency estimate for calculating emission impacts of flares. The number of flare studies is limited, and no data specifically address conditions present within vent streams of fugitive emissions from petroleum refining process unit. Five flares studies provide information on flare gas composition, flowrate, and destruction efficiency. Each study can be found in complete form in the docket. In recent tests, smokeless steam-assisted elevated flares and smokeless elevated flares with no assist were found to be as efficient as other combustion devices (i.e., 98 percent efficient) in destroying VOC over a broad range of operating conditions if the heat content of the flared gas was maintained above 7.45 MJ/scm (200 Btu/scf), or 11.2 MJ/scm (300 Btu/scf), depending upon flare design, and the exit velocity of the flare is 22 m/sec (73 ft/sec) or less.

According to the current knowledge of flare design, the best available flare design or state-of-the-art flare design is the smokeless flare. The smokeless flare inducts combustion air into the flame by steam injection. The injection of steam increases the mixing of VOC within the flame zone thereby increasing destruction of the compounds. Smoking flares are environmentally less desireable because they emit particulates.

There are a number of techniques currently in use within industry which

help flares achieve smokeless operation. One technique involves the use of staged elevated flare systems, where a small diameter flare is operated in tandem with a large diameter flare. The system is designed such that the small flare takes the continuous low flow releases and the larger flare accepts emergency releases. A second technique involves the use of a small, separate conveyance line to the flare tip in order to maintain a high exit velocity for the continuous low flow, low pressure, gas flow. A third technique, sometimes used in conjuction with either of the above techniques, involves the use of continuous flare gas recovery. In the third technique, a compressor is used to recover the continuously generated flare gas "base load." The compressor is sized to handle the "base load," and any excess gas is flared. These techniques can be used to help provide smokeless operation of a flare which is used to reduce fugitive emissions of VOC that are captured and transported by closed vent systems.

EPA considered the available control devices and their VOC reduction efficiency before selecting the proposed requirements for these devices. The flares in operation within petroleum refineries are smokeless flares. Based on the available studies and a comparison of vent stream characteristics between these studies and fugitive emission sources, EPA believes that the average destruction efficiency of an in-place petroleum refinery smokeless flare would be about 98 percent destruction efficiency. Most enclosed combustion devices are designed and can be operated to achieve VOC emission reductions of at least 98 percent. Vapor recovery systems are available which are designed and can be operated to achieve VOC emission reductions of at least 95 percent. EPA considers control devices achieving 98 percent emission reduction too costly to add to a process unit solely to control fugitive emissions in light of the presence of control devices that can achieve 95 percent control. Therefore, EPA selected a VOC reduction efficiency of 95 percent for control devices used to reduce VOC's from fugitive emission sources.

EPA selected design and operational requirements for flares, enclosed combustion devices, and vapor recovery systems used to reduce VOC's from fugitive emission sources. These requirements reflect application of the best technological system of emission reduction for these control devices. The design and operation requirements for flares, discussed above, require smokeless operation and the presence of a flame. The presence of a flame can be ensured by monitoring the flare's pilot light with a thermocouple or some other heat sensor connected to an alarm. Smokeless oepration of the flare is ensured through visible emission requirements. The proposed standards would limit visible emissions from a flare to less than 5 minutes in any 2-hour period as determined by Reference method 22. (Revisions to Reference Method 22 wil be proposed soon in the Federal Register to broaden its applicability to flares. Comments on the use of Reference Method 22 for flares will be requested at that time.) The visible emission requirement is reasonable because may refineries currently comply with State limits similar to this requirement. In addition, steam assisted flares would have to be operated with exit velocities less than 22 m/sec combusting gases with heat contents greater than 11.2 MJ/scm. Flares operated without assist would have to be operated with exit velocities less than 22 m/sec combusting gases with heat contents greater than 7.4 MJ/scm. Because enclosed combustion devices and vapor recovery systems exist that provide at least 95 percent emission reduction, a 95 percent emission reduction design requrement is proposed for these control devices. For enclosed combustion devices that do not use catalysts to aid in combustion of organic vapor streams, provisions for a minimum vapor residence time of 0.75 seconds at a minimum temperature of 816° C will be considered equivalent to at least a 95 percent emission reduction efficiency.

Miscellaneous. Flanges in all services, pressure relief devices in liquid service, and all componets in "heavy liquid" (VOC fluids of which less than 10 percent evaporate at a temperature of 150° C) VOC service would be exclud from the routine monitoring and inspection requirements. However, if leaks are detected from these sources, the same allowable repair interval which applies to compressors, pumps, and valves would apply. These sources would be excluded from routine monitoring on the basis tof data from EPA testing in petroleum refineries. Flanges in refineries have very low emission rates; and although they represent 69 percent of the total number of VOC sources in refineries, their total contribution to overall emissions is about 5.2 percent. In EPA testing of fugitive emission sources in refineries, pressure relief devices in liquid VOC service also exhibited very low emission rates. These sources contribute only 0.2 percent of all emissions from refineries. Components in "heavy liquid" VOC service have emission rates that are much lower than "light liquid" or gas service components. Since all three of these types of sources contibute a very small portion of overall emissions, applying the technology selected as BDT would result in an exorbitant cost per megagram; therefore, including them in the monitoring and equipment requrements was not considered reasonable.

Also excluded would be equipment operating under a vacuum because leaks to atmosphere would not occure while the equipment is operated at subatmospheric internal pressures.

Selection of Recordkeeping and Reporting Requirements

Recordkeeping would be required by the proposed standards to document compliance with: (1) Work practice standards, (2) equipment standards. (3) design standards. (4) emission standards, and (5) operationtional standards. Review of records would provide information for plant personnel and enforcement personnel to assess implementation of the proposed standards. Compliance with the proposed standards would be determined by inspection and review of records.

Three recordkeeping alternatives were considered in evaluating the amount of recorded information needed to assess compliance with the proposed standard.

The first alternative would require no formal recordkeeping. If recorded documentation of the proposed leak detection and repair program were not required; no mechanism would be provided for checking the thoroughness of efforts to reduce fugitive emissions. Many owners or operators would institute recordkeeping requirements to manage the efforts of their plant personnel. However, some owners or operators may not institute such programs.

The second alternative would require recordkeeping to document results of the leak detection and repair program and information relating to equipment specifications and design standards. Information would be recorded in sufficient detail to enable owners or operators to ensure that their emission reduction programs are being implemented effectively and to demonstrate compliance with the proposed standards. This alternative would require the maintenance of quantitative records of repaired and unrepaired leaking components. This alternative would require only that

amount of records necessary to manage implementation of the required programs and to ensure the effective implementation of the proposed standards.

The third alternative would require recordkeeping of all the information generated by the proposed standards. This information would include, for example, the leak rate (ppmv) detected for all components monitored at a given facility. The usefulness of this information for managing implementation of the required programs or for ensuring the effective implementation and maintenance of the proposed standards is unclear.

The second alternative was selected as the basis for the recordkeeping requirements of the proposed standards. As a consequence, general information pertaining to the leak detection and repair would be recorded. Each valve found to leak during the first month of a quarter would be marked with a readily visible, weatherproof identification. Each pump found to be leaking during a monthly monitoring would also be identified. The identification could be a tag attached to the valve or pump or a number designation permanently marked on the valve or pump. The identification could be removed after a valve is repaired and found not to leak for the next two successive months and after a pump is repaired.

A log would be maintained to record the efforts by an owner or operator pertaining to the leak detection and repair program. The log would contain the instrument and operator identification numbers, the leaking source identification number, the date of detection of the leaking source, the date of the first attempt to repair the leaking source, repair methods applied to repair the source, and the date of final repair. The log would be kept for 2 years following the survey. If the leaking component could not be repaired within 15 days, the reasons for unsuccessful repair and the date of anticipated successful repair would be recorded on the leak report form. Once the leaking source was successfully repaired, the date of repair would be recorded on the leak report form. These records would be needed to provide the information necessary to allow the owner or operator to evaluate the effectiveness of repair efforts and to allow enforcement personnel to assess compliance with the work practice standards.

For equipment specifications, records would be maintained of the dates of installation, start-up, equipment repair, and equipment modifications. The dates and descriptions of any control equipment failures, including times when the pilot light of a flare is extinquished, would also be recorded. These records would be needed to provide information necessary to allow endorcement personnel to assess the effectiveness of implementation and maintenance of equipment standards. For design standards, records would be maintained of the location and type of equipment to which the standards apply. As an example, if a combustion source is used as a VOC emission control device, then the design fuel and air usage rates, the firebox volume, and the average firebox temperature and other design specifications would be recorded.

Reporting was considered for the proposed standards. Three alternatives were considered in evaluating the reporting information needed to assess compliance with the proposed standards. These alternatives represent varying levels of enforcement monitoring of the proposed standards. Enforcement personnel would review the reports submitted by industry personnel on the status of implementing the proposed standards. Review of reports reduces the need for in-plant inspections.

The first alternative would require no formal reporting of compliance with the proposed standards other than notifications of construction, anticipated startup and actual startup, and an intention to comply with one of the alternative standards discussed in this preamble. This alternative would not provide a mechanism for checking the thoroughness of the industry's efforts to reduce fugitive emissions of VOC. Thus, compliance with the proposed standards would be assessed through in-plant inspections.

The second reporting alternative would require the submittal of information in sufficient detail to ensure the implementation and maintenance of the proposed standards. These requirements would stipulate the submittal of quarterly reports. Included in the reports would be a minimum summary of information on the leaking components which had been detected during trhe quarter. This summary of information would most likely contain less information than that which a plant manager would desire to be recorded to ensure effective emission reduction. This requirement would provide enforcement personnel with an overview of the repair of leaking components. A statement signed by the plant owner or operator attesting to the validity of the results of the monitoring surveys and instrument calibration procedures would allow enforcement personnel to assess the compliance of facilities with the work practice standards. The report would also attest to the proper application and operation of the equipment required by the proposed standards.

The third reporting alternative would require the submittal of all the information obtained while conducting leak detection and repair programs. This information would include the information reported in the second alternative and, additionally, comprehensive information on all tested components. This reporting alternative would necessitate the reporting of all information included in the recordkeeping requirements and would require more resources than the second alternative.

The first alternative was selected as the reporting requirement for the proposed standards. This alternative provides no routine reporting; therefore, compliance would be assessed through inspection of plant records and in-plant testing. A State or local agency delegated the responsibility for enforcement of the proposed standards might implement the second alternative level of reporting to facilitate enforcement of the standard; however, this would not be required by the proposed standard.

The reporting requirements of the General Provisions of Subpart A of 40 CFR Part 60, the requirements for notification of intention to comply with an alternative standard, and the reports necessary for determination of equivalence of alternative means of emission limitation would apply.

The Paperwork Reduction Act (PRA) of 1980 (Pub. L. 96-511) requires clearance from the Office of Management and Budget (OMB) of reporting and recordkeeping requirements that qualify as an "information collection request" under the PRA. OMB is currently clearing information collection requests for a period of 2 years. For the purposes of OMB's review, an analysis of the burden associated with the reporting and recordkeeping requirements of this regulation has been made. During the first 2 years of this regulation, the average annual burden of the reporting and recordkeeping requirements would be about 12 person-years, based on an average of 56 respondents per year.

Equivalence of Alternative Means of Emission Limitation

Under the provisions of Section 111(h) of the Clean Air Act, if the Administrator establishes work practices, equipment, design or operational standards, then the Administrator must allow the use of

alternative means of emission limitations if they achieve a reduction in air pollutants equivalent to that achieved under requirements of a standard of performance. Sufficient data would be required to show equivalency, and a public hearing would be required.

Individual owners or operators could request alternatives for specific requirements, such as the proposed equipment and the proposed leak detection and repair program. Sufficient information would have to be collected by a facility to demonstrate that the alternative control techniques would be equivalent to the control techniques required by the proposed standard. This information would then be submitted to EPA in a request for a determination of equivalence. If the Administrator does not deny an equivalency request, a public hearing notice would be published in the **Federal Register.**

After public notice and opportunity for public hearing, the Administrator would determine the equivalence of an alternative means of emission limitation and would publish his or her determination in the **Federal Register.**

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section address given in the ADDRESSES section of this preamble and should refer to docket number A-80-44.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (see ADDRESSES section of this preamble).

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) To allow members of the public and industries involved to identify and locate documents so they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review.

Miscellaneous

As prescribed by Section 111 of the Clean Air Act, establishment of standards of performance for the petroleum refining industry was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that sources within this industry contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. EPA welcomes comments on all aspects of the proposed regulations, including economic and technological issues. This regulation will be reviewed 4 years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and the reporting requirements.

"Major Rule" Determination. Under Executive Order 12291, the Administrator is required to judge whether a regulation is a "major rule" and, therefore, subject to certain requirements of the Order. The Administrator has determined that this regulation would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." Fifth-year annualized costs of the proposed standards would be as much as $8.2 million for the 282 newly constructed, modified, and reconstructerd production facilities projected that could be affected by the standards during the first 5 years. Significant price increases are not expected to result from implementation of these proposed standards because the annualized cost is a small fraction (0.1 percent or less) of the yearly revenue expected for the new, modified, and reconstructed units affected during the 5-year period. The Administrator has therefore concluded that this rule is not "major" under any of the criteria established in the Executive Order. The Administrator has concluded, therefore, that the proposed regulation is not a "major rule" under Executive Order 12291.

This regulation was submitted to the Office of Management and Budget for review as required by Executive Order 12291.

Regulatory Flexibility Analysis Certification. The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to current Small Business Administration guidelines, a small business in the petroleum refining industry is one that has 1,500 employees or fewer. Currently about as many as one-third of existing refineries employ fewer than 1,500 people. A reason for this high percentage is Department of Energy (DOE) subsidies that promoted their growth. These subsidies have been discontinued with decontrol of crude oil prices, and relatively little new unit construction will occur at these refineries. Since Section 111 of the Clean Air Act standards applies only to newly constructed, modified, and reconstructed production facilities, few of these small refineries are expected to be subject to the proposed standards. Even if facilities at small refineries become subject to the proposed standards, none will be adversely affected. This conclusion is based on the fact that, in doing the economic analysis for this proposal, the price increase and profitability impacts have been estimated from the perspective of the smaller refinery units in operation. Therefore, the finding that the annualized cost of the proposed standards would be 0.1 percent or less of the yearly revenue expected for units affected by the proposed standards accurately reflects the impacts for small refiners.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Ammonium sulfate plants, Asphalt concrete industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron and steel, Metals, Metallic mineral processing, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum refineries, Phosphate fertilizer industry, Sewage disposal, Sulfuric acid plants, Waste treatment and disposal, Zinc.

Dated: December 27, 1982.

John W. Hernandez, Jr.,

Acting Administrator.

PART 60—[AMENDED]

It is proposed that 40 CFR Part 60 be amended by adding a new subpart as follows:

Subpart GGG—Standards of Performance for Fugitive Emission Sources of VOC in Petroleum Refineries

Sec.

60.590 Applicability and designation of affected facility.
60.591 Definitions.
60.592–1 Standards: General.
60.592–2 Standards: Pumps in light liquid service.
60.592–3 Standards: Compressors.
60.592–4 Standards: Pressure relief devices in gas/vapor service.
60.592–5 Standards: Sampling connection systems.
60.592–6 Standards: Open-ended valves or lines.
60.592–7 Standards: Valves in gas/vapor service and valves in light liquid service.
60.592–8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.
60.592–9 Standards: Delay of repair.
60.592–10 Standards: Closed vent systems and control devices.
60.593–1 Alternative standards for valves—allowable percentage of valves leaking.
60.593–2 Alternative standards for valves—skip period leak detection and repair.
60.594 Equivalence of a means of emission limitation.
60.595 Test methods and procedures.
60.596 Recordkeeping requirements.
60.597 Reporting requirements.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart GGG—Standards of Performance for Fugitive Emission Sources of VOC in Petroleum Refineries

§60.590 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all fugitive emission sources within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 4, 1983, would be subject to the requirements of this subpart.

(c) Addition or replacement of fugitive emission sources for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) Affected facilities covered by Subpart VV or Subpart KKK of 40 CFR Part 60 and affected facilities producing natural gasoline from natural gas are excluded from this subpart.

(2) If a fugitive emission source is subject to the provisions of 40 CFR Part 61 Subpart J and 40 CFR Part 60 Subpart GGG, the source will only be required to comply with the provisions of 40 CFR Part 61 Subpart J.

§60.591 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in Subpart A of Part 60, and the following terms shall have the specific meanings given them.

"Closed Vent System" means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow inducing devices that transport gas or vapor from a compressor or a fugitive emission source to a control device.

"Connector" means flanged, screwed, welded, or other joined fittings used to connect two pipelines or a pipeline and a piece of equipment.

"Control Device" means an enclosed combustion device, vapor recovery system, or flare.

"First Attempt at Repair" means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

"Flare" means a single burner tip elevated above ground level used to burn vent gases in essentially a diffusion flame.

"Fugitive Emission Source" means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

"In Gas/Vapor Service" means that a compressor or a fugitive emission source contains process fluid that is in the gaseous state at operating conditions.

"In Light Liquid Service" means that a fugitive emission source contains a liquid that meets the conditions specified in § 60.585(e).

"In-situ sampling systems" means nonextractive samplers or in-line samplers.

"Open-Ended Valve or Line" means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side that can be open to the atmosphere, either directly or through open piping.

"Petroleum Refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

"Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

"Pressure Release" means the emission of materials from processes resulting from the system pressure being greater than the set pressure of the pressure relief device.

"Process Improvement" means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

"Process Unit" means equipment assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

"Quarter" means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

"Repaired" means that a fugitive emissions source is adjusted or otherwise altered in order to reduce fugitive emissions below 10,000 ppm, as provided in §§ 60.592–2(c)(1), –7(d)(1), –8(c)(1); or below the leak level as defined in §§ 60.592–2(d)(6)(i) and –3(f).

"Sensor" means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, or pH.

"In Vacuum Service" means that a fugitive emission source is operating at an internal pressure which is at least 5kPa below ambient pressure.

"Volatile Organic Compound (VOC)" means any organic compound which participates in atmospheric photochemical reactions. An organic compound participates in atmospheric reactions unless the Administrator determines that it does not.

"In VOC Service" means that a compressor or a fugitive emission source contains or contacts a process fluid that is at least 10 percent VOC by weight as determined according to the provisions of § 60.595.

§ 60.592–1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of § 60.592–1 to § 60.592–10 as soon as practicable, but not later than 180 days after initial startup.

(b) Compliance with § 60.592–1 to § 60.592–10 will be determined by review of records, review of performance test results, and inspection

using the methods and procedures specified in § 60.595.

(c)(1) A determination of equivalence of alternative means of emission limitation to the requirements of §§ 60.592–2, –3, –5, –6, –7, –8, and –10 may be requested as provided in § 60.594.

(2) If the Administrator determines that a means of emission limitation is at least equivalent to the requirements of §§ 60.592–2, –3, –5, –6, –7, –8, or –10 the requirements of that determination will apply.

(d) Fugitive emission sources that are in vacuum service may be excluded from the requirements of §60.592–1 to § 60.592–10 if they are identified as required in § 60.596(e)(4).

§ 60.592–2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.595(b), expect as provded in § 60.592–1(c) and §§ 60.592–2 (d), (e), and (f).

(2) Each pump shall be checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected, or

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected except as provided in § 60.592–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(3) If repair requires that the pump be equipped with a dual mechanical seal system that includes a barrier fluid system, then repair shall be completed no later than 6 months after the leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of § 60.592–2(a) provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is connected by a closed vent system to a control device as described to § 60.592–10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with no VOC emission to atmosphere.

(2) The barrier fluid is not in light liquid service or gas/vapor service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seal.

(5)(i) Each sensor as described in § 60.592–2(d)(3) is checked daily or is equipped with an audible alarm, and

(ii) Based on design considerations and operating experience, the owner or operator shall demonstrate a criterion that indicates failure of the seal system, the barrier fluid system, or both as determined by the owner or operator for each sensor.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both, a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected except as provided in § 60.592–9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in § 60.596(e)(1), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of §§ 60.592–2(a), (c), and (d) if the pump:

(1) Has no externally actuated shaft penetrating the pump housing,

(2) Is operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.595(c), and

(3) Is tested for compliance with § 60.592—2(e)(2) initially, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device as described in § 60.592–10, it is exempt from the §§ 60.592–2(a)–(e).

§ 60.592–3 Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.592–1(c) and §§ 60.592–3(h) and (i).

(b) Each compressor seal system as required in § 60.592–3(a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system that is connected by a closed vent system to a control device as described in § 60.592–10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with no VOC emission to the atmosphere.

(c) The barrier fluid is not in light liquid service or gas/vapor service or is not in VOC service.

(d) Each barrier fluid system as described in § 60.592–3(a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in § 60.592–3(d) shall be checked daily or shall be equipped with an audible alarm.

(2) Based on design considerations and operating experience, an owner or operator shall demonstrate a criterion that indicates failure of the seal system, the barrier fluid system, or both shall be determined by the owner or operator for each sensor installed on a compressor seal system.

(f) If the criterion determined under § 60.592–3(e)(2) is registered by the sensor, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected except as provided in § 60.592–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) Any compressor that is not equipped as described in §§ 60.592–3(a) and (b) shall be equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device as described in § 60.592–10.

(i) Any compressor that is designated, as described in § 60.596(e)(1), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of §§ 60.592–3(a)–(h) if the compressor:

(1) Is operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.595(c); and

(2) Is tested for compliance with § 60.592–3(i)(1) initially, annually, and at other times requested by the Administrator.

§ 60.592–4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.595(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.592–9.

(2) No later than 5 calendar days after the pressure release the pressure relief device shall be monitored to confirm the condition of no detectable emissions, as indicated by an instrument reading of 500 ppm above background, as measured by the methods specified in § 60.595(c).

(c) Closed vent systems and control devices, as described in § 60.592–10, that are used to comply with §§ 60.592–4(a) and (b) shall be designed and operated on at all times when VOC emissions may occur.

§ 60.592–5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed purge system.

(b) Each closed purge system as required in § 60.592–5(a) shall:

(1) Return the purged process fluid directly to the process line without VOC emissions to atmosphere, or

(2) Collect and recycle the purged process fluid without VOC emissions to atmosphere.

(3) Be designed and operated to capture and transport all the purged process fluid to a control device complying with the requirements of § 60.592–10.

(c) In-situ sampling systems are exempt from §§ 60.592–5(a) and (b).

§ 60.592–6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve.

(2) The cap, blind flange, plug, or second closed valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

§ 60.592–7 Standards: Valves in gas/vapor service and valves in light liquid service.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.595(b) and shall comply with §§ 60.592–7(b)–(e), except as provided in §§ 60.592–7 (f), (g), and (h) and § 60.593–1 and 2.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.592–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.596(e)(1), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of § 60.592–7(a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.595(c), and

(3) Is tested for compliance with § 60.592–7(f)(2) initially, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as required in § 60.596(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of § 60.592–7(a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with § 60.592–7(a), and

(2) The owner or operator of the valve has a written plan that requires monitoring of the valve as frequent as practicable during safe-to-monitor times.

(h) Any valve that is designated, as required in § 60.596(f)(2), as a difficult-to-monitor valve is exempt from the requirements of § 60.592–7(a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located becomes an affected facility through § 60.14 or § 60.15, and

(3) The owner or operator of the valve has a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.592–8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid and heavy liquid service, and flanges and other connectors.

(a) Pumps and valves in heavy liquid service, pressure relief devices in light liquid and heavy liquid service, and flanges and other connectors shall be monitored within 5 days by the method specified in § 60.595(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.592–9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under § 60.592–7(e).

§ 60.592–9 Standards: Delay of repair.

(a) Delay of repair of compressors and fugitive emission sources for which leaks have been detected will be allowed if the repair is technically infeasible without a complete or partical process unit shutdown.

(b) Delay of repair beyond a process unit shutdown will be allowed for valves, if valve assembly replacement is necessary during the process until shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.

§ 60.592–10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to

recover the organic vapors vented to them with an efficiency of 95 percent or greater.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C.

(d)(1) Flares shall be designed for and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any period of 2 consecutive hours as determined by methods in § 60.595(g).

(2) Flares shall operate with a flame at all times.

(3) Flares shall be operated with exit velocities less than 22 meters per second as determined for the gas being combusted at the flare tip.

(4) Flares shall be elevated above ground level and operate without assist or with steam assist.

(5) Steam assisted flares shall combust gases with the net heating value of the gases greater than 11.2 Megajoule per standard cubic meter (300 Btu/scf).

(6) Flares operated without assist shall combust gases with the net heating value of the gases greater than 7.4 Megajoule per standard cubic meter (200 Btu/scf).

(e) Owners or operators of control devices that are used to comply with the provision of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their design.

(f)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.595(c).

(2) Closed vent systems shall be monitored annually and at other times requested by the Administrator.

(3) Leaks, as indicated by an instrument reading greater than 500 ppm, shall be repaired within 15 calendar days.

(g) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.593–1 Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to have the valves comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to have the valves comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to have the valves comply with the allowable percentage of valves leaking before implementing this alternative standard.

(2) A performance test as specified in § 60.593–1(c) shall be conducted initially, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it must be repaired in accordance with § 60.593–7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor service and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.595(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standards shall not have an affected facility with a leak percentage greater than 2.0 percent.

(e) If an owner or operator no longer wishes the valves to comply with § 60.593–1, the owner or operator must notify the Administrator in writing that the work practice standard described in §§ 60.592–7(a)–(e) will be followed.

§ 60.593–2 Alternative Standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in § 60.593–2(b).

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices of § 60.593–2(b), as specified in § 60.597(b).

(b)(1)(i) An owner or operator shall comply with a reference leak detection program.

(ii) The reference leak detection program shall conform to the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.592–7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the reference leak detection program, as described in § 60.592–7, but can again elect to use §§ 60.593–2(b)(2) or –2(b)93).

§ 60.594 Equivalent means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of any equivalent means of emission limitation.

(2) The Administrator will compare test data for the equivalent means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit to compliance with a performance that provides for emission reductions equal to or greater than the

emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practice and will consider the commitment in § 60.594(c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the **Federal Register** and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of means of emission limitation and will publish the determination in the **Federal Register.**

(3) Any equivalent means of emission limitation approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of Section 111(h)(1) of the Clean Air Act.

(f)(1) Manufacturers of equipment used to control fugitive emissions of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of §§ 60.594(b), (c), (d), and (e).

§ 60.595 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test methods and procedures requirements provided in this section.

(b) Monitoring, as required in §§ 60.592, 60.593, and 60.594, shall comply with the following requirements:

(1) Monitoring shall comply with Reference Method 21.

(2) The VOC detection instrument shall meet the performance criteria of Reference Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the methods specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 3 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately but less than 10,000 ppm methane or n-hexane.

(5) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(c) When compressors or fugitive emission sources are tested for compliance with no detectable emissions as required in §§ 60.592–2(e), –3(i), –4, –7(f) and –10(e), the test shall comply with the following requirements:

(1) The requirements of §§ 60.595(b)(1)–(4) shall apply.

(2) The background level shall be determined, as set forth in Reference Method 21.

(3) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(4) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d)(1) For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a compressor or a fugitive emission source, procedures that conform to the methods described in ASTM Method E–260 (incorporated by reference as specified in § 60.18) shall be used.

(2) If an owner or operator decides to exclude nonphotochemically reactive substances from the percent VOC content of the process fluid, the exclusion will be allowed provided:

(i) Those substances excluded are considered nonphotochemically reactive by the Administrator; and

(ii) The owner or operator demonstrates that the percent VOC content, excluding nonphotochemically reactive substances, can be reasonably expected never to exceed 10 percent VOC by weight.

(e) A fugitive emission source is in light liquid service if the percent evaporated is greater than 10 percent at 150°C as determined by ASTM Method D–86 (incorporated by reference as specified in §60.18).

(f) Samples used in conjunction with §§ 60.595(d) and (e) shall be representative of the process fluid that is contained in or contacts the fugitive emission source.

(g) Reference Method 22 shall be used to determine the compliance of flares with the provisions of this subpart.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.596 Recordkeeping requirements.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(b) When each leak is detected as specified in §§ 60.592–2, –3, –7, and –8, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the source identification number, shall be attached to the leading source.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.592–7(c) and no leak has been detected during those 2 months.

(3) The identification on a compressor or fugitive emission source, except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.592–2, –3, –7, and –8, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the fugitive emission source identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10,000" if the maximum instrument reading measured by the methods specified in § 60.595(a) after each repair attempt is greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.592–10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) Periods when the closed vent systems and control devices required in

§§ 60.592–2, –3, –4, and –5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(4) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.592–2, –3, –4, and –5.

(e) The following information pertaining to all compressors and fugitive emission sources subject to the requirements in §§ 60.592–2, –3, –4, and –7 shall be recorded in a log that is kept in a readily accessible location:

(1)(i) A list of identification numbers for fugitive emission sources that the owner or operator elects to designate for no detectable emissions under the provisions of §§ 60.592–2(e), –3(i), and –7(f).

(ii) The designation of these sources as subject to the requirements of §§ 60.592–2(e), –3(i), or –7(f) shall be signed by the owner or operator.

(2) A list of source identification numbers for pressure relief devices required to comply with § 60.592–4.

(3)(i) The dates of each compliance test required in §§ 60.592–2(e), –3(i), –4, and –7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the source during each compliance test.

(4) A list of identification numbers for fugitive emission sources that are in vacuum service.

(f) The following information pertaining to all valves subject to the requirements of §§ 60.592–7 (g) and (h) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves that are designated as unsafe to monitor, an explanation for each valve stating why the valve is unsafe to monitor, and the plan for monitoring each valve.

(2) A list of identification numbers for valves that are designated as difficult to monitor, an explanation for each valve stating why the valve is difficult to monitor, and the expected date for monitoring each valve.

(g) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in § 60.592–2(d)(5) and § 60.592–3(e)(2) and an explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for this change.

(h) The provisions of §§ 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.597 Reporting requirements.

(a) An owner or operator electing to comply with the provisions of §§ 60.593–1 and –2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(b) The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator shall notify the Administrator of the schedule for the initial performance tests 30 days before the initial performance tests.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2070-6]

Standards of Performance for New Stationary Sources—Graphic Arts Industry: Publication Rotogravure Printing

Correction

In FR Doc. 82-30410 beginning on page 50644 in the issue of Monday, November 8, 1982, make the following corrections:

(1) On page 50644, third column, in the 17th line from the top of the page, "solvent-borne are" should have read "solvent-borne inks are".

(2) On page 50655, middle column, in paragraph 2.3 of **Method 24A** under Appendix A, in the sixth line, "D_o" should have read "$\overline{D}_o$".

(3) On the same page, in the third column, the equation at the top of the page should have been labeled "Equation 24A-1", and "Report the weight fraction VOC W_o" should have read "Report the weight fraction **VOC** $\overline{W}_o$".

(4) In the same column, the second equation should have been labeled "Equation 24A-2", and the plus sign should have been an equal sign.

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40 CFR Part 60

[AD-FRL-2070-7]

Standards of Performance for New Stationary Sources; Metal Coil Surface Coating Operations

Correction

In FR Doc. 82-29693 beginning on page 49606 in the issue of Monday, November 1, 1982, make the following corrections:

(1) On page 49606, first column, in the 12th and 13th lines of the **SUMMARY** paragraph, "to all pollution" should have read "to air pollution".

(2) On page 49615, in § 60.463(c)(4)(vii), in the seventh line from the bottom of the third column, "which is" should have read "whichever is".

(3) On page 49616, in § 60.463(c)(4)(ix), "which is greater" should have read "whichever is greater".

(4) In the same column, under § 60.464, in the ninth line of paragraph (c), "±2.5°" should have read "±2.5°C."

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federal register

Thursday
January 20, 1983

Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Rubber Tire Manufacturing Industry; Proposed Rule and Public Hearing

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 1907-8]

Standards of Performance for New Stationary Sources; Rubber Tire Manufacturing Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standards would limit volatile organic compound (VOC) emissions from new, modified, and reconstructed facilities within rubber tire manufacturing plants. The proposed standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination that emissions from rubber tire manufacturing plants cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intent is to require new, modified, and reconstructed facilities at rubber tire manufacturing plants to control emissions to the levels achievable through use of the best demonstrated systems of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before April 1, 1983.

Public Hearing. A public hearing will be held on March 3, 1983 beginning at 9 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony must contact EPA by February 9, 1983.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to: Central Docket Section (A-130), Attention: Docket Number A-80-9, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

Public Hearing. The public hearing will be held at the Office of Administration Auditorium, Research Triangle Park, N.C. Persons wishing to present oral testimony should notify Mrs. Naomi Durkee, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

Background Information document. The Background Information Document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Rubber Tire Manufacturing Industry—Background Information for Proposed Standards," EPA 450/3-81-008a.

Docket: Docket No. A-80-9, containing supporting information used in developing the proposed standards, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Ms. Susan R. Wyatt, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

SUPPLEMENTARY INFORMATION:

Proposed Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> • • • Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (Section 111(a)(1)).

The proposed standards would limit VOC emissions from new, modified, and reconstructed facilities. The affected facilities would be each undertread cementing operation, each sidewall cementing operation, each tread end cementing operation, each bead cementing operation, each inside green tire spraying operation, each outside green tire spraying operation, each Michelin-A operation, each Michelin-B operation, and each Michelin-C-automatic operation.

Facilities affected by the proposed standards would be those where components for agricultural, airplane, industrial, mobile home, light-duty truck or passenger vehicle tires which have a bead diameter up to and including 0.5 meter (m) [19.7 inches (in)] and cross section dimension up to and including 0.325 m (12.8 in) are mass produced in assembly-line fashion.

VOC emissions from the rubber tire industry are caused by solvent application to different components of a tire during the manufacturing process. To meet the proposed standards for each undertread cementing and sidewall cementing operation, an owner or operator would have the option of using less solvent and maintaining emissions at or below 25 grams per tire (a level currently achieved at some plants) without the use of an emission reduction system, or installing a 75 percent efficient emission reduction system if solvent use exceeds 25 g/tire. Using less solvent has the advantages of no cost (other than possibly developmental cost), no energy usage, and solvent conservation. The proposed standards for four affected facilities are based on the use of less solvent and would require that emissions be limited to 10 grams per tire (g/tire) for each tread end cementing and each bead cementing operation, 1.2 g/tire for each inside green tire spraying operation, and 9.3 g/tire for each outside green tire spraying operation. Thus, the proposed standards are structured so they could be met through solvent use reductions without employment of a control device.

The proposed standards would require 75 percent emission reduction for each Michelin-B operation and 65 percent emission reduction for each Michelin-A and Michelin-C-automatic operation.

Separate testing, monitoring, and recordkeeping requirements are proposed for each combination of standard format (g/tire or percent emission reduction), control technique (low solvent use or emission reduction system), and compliance method (performance tests or equipment specifications). Initial performance tests would be required for each affected facility, unless the owner or operator chooses to demonstrate compliance with the recommended standards by meeting the equipment specifications. An exemption has been provided for facilities that meet the equipment specifications. The proposed standards would require the owner or operator to report the results of all initial performance tests.

Monthly performance tests would be required to determine compliance with each of the g/tire limits. Whether or not monthly performance tests would be required to determine compliance with the percent emission reduction standards depends primarily on the type of control device used, and then on the method of demonstrating compliance. The proposed standards would not

require an owner or operator to report results of monthly performance tests.

The proposed standards would require continuous monitoring and recording of thermal incinerator combustion temperature and the temperature before and after the catalyst for catalytic incinerators. The requirement for a continuous monitor on a solvent recovery system is not applicable until performance specifications for the monitor have been proposed and promulgated. The proposed standards would require that the owner or operator maintain at the source for a period of at least two years records of all data and calculations used to determine VOC emissions for each affected facility.

Reference Method 24 would be used to determine the VOC content of cements and green tire spray materials. Reference Method 25 would be used to determine the concentration of VOC in exhaust gas streams.

Summary of Environmental, Energy, and Economic Impacts

The incremental impacts of the proposed standards in the Background Information Document were determined using the levels of emission reduction recommended in the control technique guidelines (CTG) document, "Control of Volatile Organic Compound Emissions from Manufacture of Pneumatic Rubber Tires" (EPA–450/2–78–030), as the regulatory baseline. This assumes that in the absence of standards of performance, all new, modified, and reconstructed facilities would be required to limit volatile organic compound emissions to the levels recommended in the CTG. The CTG recommends an average overall emission reduction of about 70 percent from undertread cementing, tread end cementing, bead cementing, and inside and outside green tire spraying operations. This reduction would be achieved by using emission reduction systems at each of these affected facilities. Water-based sprays could also be used at inside and outside green tire spraying operations.

State Implementation Plans (SIPs) are currently being revised, and the level of control which would actually be required for a particular rubber tire plant in the absence of these proposed standards of performance is uncertain. Some States may adopt regulations that require different levels of emission reduction than the regulatory baseline or that allow the use of emission reduction strategies different from those assumed for the regulatory baseline. Some States may not include regulations limiting VOC emissions from rubber tire manufacturing plants in their SIPs. Therefore, basing the impacts of the proposed standards on the assumption that all plants would be controlled to the level recommended in the CTG tends to underestimate the emission reductions and costs of the proposed standards. Therefore, in this summary, the impacts of the proposed standards are presented two ways: (1) As the difference between uncontrolled levels and the proposed standards, and (2) as the difference between the regulatory baseline and the proposed standards. The actual impacts of the proposed standards will depend on the mix of control levels required by States and the location of newly constructed, modified, and reconstructed facilities, and will be between the two sets of numbers presented here.

Compared to the regulatory baseline, the proposed standards would reduce nationwide emissions from newly constructed, modified, and reconstructed facilities by 1,430 Mg (1,570 tons) in the fifth year after proposal. This represents a 46 percent reduction in emissions beyond the CTG baseline. For a single medium-sized plant, the emission reduction compared to the baseline, would be 375 Mg (415 tons).

Compared to the uncontrolled levels, the proposed standards would reduce nationwide emissions by 8,285 Mg (9,130 tons). This represents an 83 percent reduction from uncontrolled levels. For a single medium-sized plant, the emission reduction compared to uncontrolled levels would be 1,775 Mg (1,960 tons) per year.

Compared to the regulatory baseline, the proposed standards would not result in an increase from baseline levels of water pollution and solid waste or energy consumption. Since baseline levels of water pollution, solid waste, and energy consumption show no significant increase over uncontrolled levels, the proposed standards also show no significant increase over uncontrolled levels.

Control costs calculated for the regulatory baseline assume that each affected facility would use a VOC emission reduction system to control emissions except for inside and outside green tire spraying operations, where water-based sprays were assumed to be used. Since the proposed standards are partially based on process modifications, both the capital and annualized costs to comply with the proposed standards are smaller than the costs projected to comply with the baseline levels. The total nationwide capital cost for VOC emission reduction from uncontrolled levels to the level of the proposed standards would be about $10.8 million during the first five years. The total nationwide annualized cost in the fifth year would be about $1.5 million, with solvent recovery credits. (Without solvent recovery credits, the nationwide annualized cost would be about $3.4 million; recovery credits are anticipated.) For a single medium-sized plant controlling all affected facilities to the level of the proposed standards, the annualized cost would be approximately $110,000 if credit is given for solvent recovery or $403,000 without solvent recovery credit.

Price increases and reductions in return on investment (ROI) are projected to be zero compared to those projected for the baseline control level. Assuming all costs are passed through to consumers, the average increase in the retail price of a tire from uncontrolled levels would be about 0.26 percent in the worst case. Upon full cost absorption, using no control as a base of comparison, the return on investment (ROI) of new radial tire manufacturing plants may decline from an assumed rate of 5.17 percent to 5.04 percent in the worst case. Worst case conditions in both situations are represented by the use of a separate capture system and carbon adsorber control device at each affected facility where control equipment is used to achieve emission reductions. These impacts are not expected to inhibit industry growth.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having less stringent air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies. The costs are provided for an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact of controls on an industry.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government,

and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

Rationale

Selection Source

The EPA Priority List (40 CFR Part 60, § 60.16, 44 FR 49222, August 21, 1979) reflects the Administrator's determination that emissions from the listed source categories contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The Priority List identifies major sources of emissions on a nationwide basis in order of priority for regulation based on three factors: (1) quantities of emissions from source categories, (2) the mobility and competitive nature of each source category, and (3) the extent to which each pollutant endangers health or welfare. Tire manufacturing is included on the Priority List as a subcategory under Synthetic Rubber, which is ranked number 20 out of a total of 59 source categories. Rubber tire manufacturing industry VOC emissions for 1979 were estimated to be about 59,000 Mg (65,000 tons).

About 140,000 tires per day will be produced by new, modified and reconstructed facilities in operation by 1985. In the absence of additional regulation, new, modified, and reconstructed facilities would emit about 3,120 Mg of VOC per year (3,430 tons/yr).

Emission reduction systems composed of a capture system and control device are available to the industry for reducing VOC emissions. Water-based green tire sprays with low VOC content are in use at many plants. Techniques which minimize solvent use can reduce emissions from tread end cementing and bead cementing operatings. The predicted growth of this industry with its attendant increase in emissions and the availability of control technology further support the development of standards of performance for this industry.

Selection of Pollutants and Affected Facilities

At a rubber tire manufacturing plant, raw rubber and chemicals are first mixed in proportions determined by specifications for the tire component in which the rubber will be used. The rubber is then transported to different parts of the plant for processing into various components, such as treads, sidewalls, beads, plies, and belts. In some of these processes rubber is combined with fabric, steel, or fiberglass. Manufactured components are brought together and assembled at a tire building area. The assembled green tire is sprayed with a green tire spray, which acts as a mold release agent and lubricant, and placed in a press where, with a specific combination of time, temperature, and pressure, the tire is molded to its final form and the rubber is cured. Tires are then inspected for quality and appearance, or "finished."

VOC is used at several points in the tire manufacturing process. Organic solvents or organic solvent-based cements are aplied to components during production or during tire building to facilitate adhesion. Organic solvents are used in many green tire sprays to facilitate application of mold release and lubricating agents and at finishing, where minor cosmetic repairs are made.

The processes used to manufacture components and to assemble tires vary among companies and among plants owned by the same company. Whether any VOC is used in a process and in what amounts also vary among companies and plants owned by the same company. Each company considers some or all of its production precesses to be proprietary. In developing the proposed standards, EPA was requested to maintain the confidentiality of much of the process and solvent use data submitted by industry. At the same time EPA sought to develop regulations which reflect use of best systems of continuous emission reduction and which apply equitably to each manufacturer. Futher, EPA sought to avoid proposing any requirement which would adversely affect tire safety and performance.

Volatile organic compounds (VOC) are the principal pollutants emitted to the atmosphere from rubber tire manufacturing plants. The VOC emitted from all but one company's plants is predominantly white gasoline and petroleum naphtha. Heptane is the major solvent used at one company's plants. Toluene, xylene, ketones, and esters are also used throughout the industry, but in smaller amounts.

About 98 percent of the VOC emitted from an average uncontrolled existing plant results from solvent application in seven solvent-using processes. These processes and their average contribution to overall plant VOC emissions, as calculated from solvent use and tire production data, provided by industry, are shown below:

Process	Emission contribution (percent)
Undertread cementing	20.5
Sidewall cementing	13.3
Tread end cementing	4.9
Bead cementing	2.7
Tire building	10.7
Inside green tire spraying (organic solvent-based)	5.6
Outside green tire spraying (organic solvent-based)	28.9
Finishing	1.3
Non solvent-using facilities	1.8
Total	100

Industry-supplied data show wide variations in solvent usage rates among companies and among plants owned by the same company. These differences occur for a variety of reasons, including differences in specifications for how tires are to be produced, and the types of tires produced.

Emissions are significant at undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying operations. Further, emission reduction technology is available and is technically and economically feasible for use at each of these types of operations. Therefore, these operations were selected for control by the proposed standards.

Tire building, while contributing about 11 percent of total plant emissions, is characterized by low VOC concentrations emanating from 50 or more individual machines within each plant. The need for liberal worker access dictates that machines be open, and, as a result, high ventilation rates would be needed to remove organic vapors to a control device. Technically, control systems could be constructed to reduce VOC emissions from tire building. The air in the tire building room could be ducted to a control device such as an incinerator or carbon adsorber. However, exhaust stream VOC concentrations in existing tire building areas where general dilution ventilation is employed are very low, ranging from 0.01 to 0.32 g/m^3 (0.6×10^{-6} to 20.0×10^{-6} lb/ft^3). The cost of such a system would range from $68,000 per Mg of VOC removed ($62,000/ton) to $306,000 per Mg of VOC removed ($280,000/ton). The Administrator concluded that these costs are exorbitant for the emission reduction achieved and has not included tire building in the proposed standards.

Finishing contributes about 2 percent of total plant emissions. Organic solvent is used in protective coatings for whitewalls and in coating used for cosmetic purposes. Both uses, while

performed in separate areas, are part of the finishing process. Solvent application is intermittent and is performed at worker discretion. For these reasons, finishing has not been included in the proposed standards.

Compounding, milling, extrusion, calendering, and curing, where no organic solvent is used, together account for less than 2 percent of total plant VOC emissions, and have not been included in the proposed standards.

Michelin Tire Corporation uses three operations, referred to in this preamble and in the regulation as "Michelin-A," "Michelin-B," and "Michelin-C," for which they have claimed confidentiality. EPA is currently treating the specific information provided by Michelin on these operations as confidential and has initiated a confidentiality determination in accordance with 40 CFR Part 2. Since Michelin-A, Michelin-B, and Michelin-C are operations believed unique to the Michelin Tire Corporation, emissions from these operations were not included in the above list. VOC emissions from each of these operations are significant, and collectively account for a substantial portion of total uncontrolled emissions from each Michelin plant.

Emission reduction technology which is technically and economically feasible is available for use at Michelin-A and Michelin-B operations. Therefore, Michelin-A and Michelin-B operations were selected for control by the proposed standards.

The Michelin-C operation is performed with either manual or automatic cement application depending on the type of tire being made. Emission reduction technology, which is technically and economically feasible, is available for use at automatic Michelin-C operations. Therefore, Michelin-C-automatic operations were selected for control by the proposed standards. VOC concentrations in the exhaust streams from manual Michelin-C operations are reportedly very low, ranging from 0.10 to 0.30 g/m^3. The cost of operating an emission reduction system at a manual Michelin-C operation would be similar to that previously stated for tire building. The Administrator has concluded that these costs are exorbitant for the emission reduction achieved and has not included manual Michelin-C operations in the proposed standards. Not all tires manufactured by Michelin Tire Corporation can be made using the Michelin-C-automatic operation. Therefore, the proposed standards do not preclude the use of manual Michelin-C operations.

Affected Facilities

The choice of the affected facility(ies) for this standard is based on the Agency's interpretation of Section 111 of the Act and judicial construction of its meaning. Under Section 111, the NSPS must apply to "new sources;" "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" [Section 111(a)(3)]. Most industrial plants, however, consist of numerous pieces or groups of equipment which emit air pollutants, and which might be viewed as "sources." EPA therefore uses the term "affected facility" to designate the equipment, within a particular kind of plant, which is chosen as the "source" covered by a given standard.

In choosing the affected facility, EPA must decide which pieces or groups of equipment are the appropriate units for separate emission standards. The Agency must do this in light of the terms and purpose of Section 111. One major consideration is that the use of a narrower definition results in bringing replacement equipment under the NSPS sooner. For example, if an entire plant were designated as the affected facility, no part of an existing plant would be subject to the standard unless the plant as a whole were "modified." If on the other hand, each piece of equipment were designated as an affected facility, then as each piece was replaced, the replacement piece would be a new source subject to the standard. Since the purpose of Section 111 is to minimize emissions by the application of the best demonstrated control technology (considering cost, other health and environmental effects, and energy requirements) at all new and modified sources, there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources would be subject to the standards as they are installed. This presumption can be overcome, however, if the Agency concludes that relevant statutory factors (technical feasibiltiy, cost, energy, and ther environmental impacts) point to a broader definition.

In a rubber tire plant, the narrowest designation of affected facility for which standards of performance might be appropriate is each individual operation. The rubber tire industry maintains that much of the anticipated growth in the industry by 1985 will result from non-routine replacement of existing operations with new operations. New individual operations would qualify as new sources subject to standards of performance under this narrowest definition of affected facility. As a result, control costs were calculated assuming each operation would be controlled separately. In practice, however, a single control device could be used to control emissions from several operations. Examination of these costs showed that control is economically feasible (i.e., the costs would not inhibit growth or replacement) in all cases where a separate emission reduction system would be used at an individual operation. Defining an affected facility as each separate operation is supported by technical, cost, and economic considerations. The Agency requests comments from interested parties about this definition of an affected facility.

With each operation defined as an affected facility, any change which qualified as a modification or reconstruction would cause only that changed operation to become subject to standards of performance. Further, if a new operation were constructed at an existing plant where other operations were not subject to standards of performance, only the new operation would be subject to standards of performance.

Undertread cementing and tread end cementing are usually performed at different points on the same tread line. At an undertread cementing operation, cement is applied to a continuous strip of tread rubber or to a combined tread/sidewall component. The tread rubber is usually transported from the extruder to the undertread cementing operation by a conveyor. After cement is applied, the tread rubber strip passes along a conveyor where it air dries and then usually through a water bath for cooling. At undertread cementing operations, VOC is emitted from cement storage and application equipment and from cemented rubber as VOC evaporates after application. Therefore, an undertread cementing operation consists of a cement application station and all other equipment, such as the cement supply system, and feed and takeaway conveyors, which are necessary to apply cement to tread or combined tread/sidewall components and to allow evaporation of solvent from tread or combined tread/sidewall components. Each undertread cementing operation is an affected facility.

After the water bath and forced-air drying, the continuous strip is cut to specified lengths and then is usually conveyed to a tread end cementing operation. At a tread end cementing operation, cement is applied to one or both tread ends. Cement is usually applied to tread ends either by spraying with an electronically-triggered automatic spray arm or manually by a

worker equipped with a pot of cement and an applicator. VOC is also emitted from cement storage and application equipment and from cemented treads as VOC evaporates after application. Therefore, a tread end cementing operation consists of a cement application station and all other equipment, such as the cement supply system, and feed and takeaway conveyors, which is necessary to apply cement to tread end components and to allow evaporation of solvent from tread ends. Each tread end cementing operation is an affected facility. Although undertread cementing and tread end cementing operations are usually performed on the same tread line, they are separate emission points and each can be controlled separately. This supports designating each tread end cementing operation as an affected facility separate from each undertread cementing operation.

For some types of tires, sidewalls may be extruded as part of the tread. Cement application for this tread/sidewall component usually occurs at an undertread cementing operation, and VOC emissions are counted as part of those from undertread cementing. When sidewall cementing is performed as a separate operation, the extrusion, conveying, cementing, and cooling equipment is usually similar to but smaller than that used for undertread cementing. Instead of being cut to specific lengths, however, the continuous sidewall strip is rolled in a non-stick fabric and stored until needed. VOC is emitted from cement storage and application equipment and from cemented rubber as VOC evaporates after application. Therefore, a sidewall cementing operation consists of a cement application station and all other equipment, such as the cement supply system, and feed and takeaway conveyors, which is necessary to apply cement to sidewall components and to allow evaporation of solvent from sidewall components. Each sidewall cementing operation is an affected facility.

Bead cementing may occur before or after the rubber-coated wire is fashioned into a bead. If cement is applied before bead fashioning, the cement application apparatus is usually a swab or roller suspended in a trough of cement attached to the bead fashioning equipment. Cement is applied as the rubber-coated wire passes over the trough. If cement is applied after beads are fashioned, it is usually accomplished by spraying or by dipping the beads into a vat of cement. Spraying or dipping equipment is separate from bead fashioning equipment. A bead cementing operation consists of a cement application station, such as a dip tank, spray booth and nozzles, cement trough, and roller or swab applicator; and all other equipment necessary to apply cement to beads or bead components and to allow the evaporation of solvent from cemented beads. Each bead cementing operation is an affected facility.

Green tire sprays are usually applied inside and outside with automatic spray nozzles. Whether water-based or organic solvent-based inside and outside green tire sprays are used, outside sprays usually contain more VOC than inside sprays. Inside and outside sprays are usually applied using different nozzles in the same booth. However, different booths may be employed at some plants. The spray booth is designed to contain overspray and vent it to a dust collector or uncontrolled to the atomosphere. Inside green tire spraying and outside green tire spraying are separate operations and are separate affected facilities. An inside green tire spraying operation consists of the inside spray application station and related equipment, such as the lubricant supply system, the booth where spraying is performed, and associated fans and ductwork. Each inside green tire spraying operation is an affected facility. An outside green tire spraying operation consists of the outside spray application station and related equipment, such as the lubricant supply system, the booth where spraying is performed, and associated fans and ductwork. Each outside green tire spraying operation is an affected facility.

Cement is applied to tire components at Michelin-A, Michelin-B, and Michelin-C-automatic operations. Each of these operations is distinct and has VOC emissions which can be accounted for and controlled independently. Each operation consists of cement storage and application equipment, and other equipment necessary for the application of cement to and the evaporation of VOC from tire components processed at the operation. Each Michelin-A, Michelin-B, and Michelin-C-automatic operation is an affected facility.

Selection of Basis of Proposed Standard

Three general methods of emission reduction technology are available to the rubber tire manufacturing industry: (1) emission reduction systems (capture and control); (2) low solvent use techniques; and (3) low VOC content materials.

Emission Reduction Systems

Current use of emission reduction systems is limited in the rubber tire industry. Only two such systems are present in this industry, both employing carbon adsorbers as the control device. One of these systems is part of the original design of the undertread cementing process at a new plant. This plant has not yet operated at full production capacity, and emission control data on the new system are not yet available. The other system is the only emission reduction system in full use in the industry. It consists of a capture system and carbon adsorber installed on an undertread cementing line in 1973 and has been shown by materials balance calculations to have an average solvent recovery efficiency of about 63 percent. The carbon adsorber has been tested separately and shown to be about 90 percent efficient, thus the capture system averages about 70 percent efficiency. The company operating this system has submitted information concerning factors which limit system performance. Factors which according to the company limit system efficiency include:

(1) About 8 percent of VOC applied to a rubber component is absorbed by the rubber and is not immediately available for capture (emissions from cemented rubber account for about 30 percent of total VOC emissions from this line, thus about 2.4 percent of VOC used is absorbed);

(2) Enclosure system access doors are open for a finite period for periodic threading of new tread sizes;

(3) Length of the drying area conveyor is limited by the configuration of existing extrusion equipment;

(4) The switching damper installed for enclosure emergency situations is not equipped with vapor loss seals;

(5) Operating practices do not provide for containment of VOC emissions during weekend shutdown, either by draining cement tanks or by equipping tanks with tight fitting covers;

(6) Operating practices do not provide for air drying and cooling of the desorbed carbon bed prior to the next adsorption cycle; and

(7) The company does not account for vapor losses from cement mixing churns, recirculating cement distribution system storage tanks, recovered solvent storage tanks, pumping, and venting from decanter.

In EPA's judgment, this type of emission reduction system could be improved to achieve an overall efficiency of 75 percent or better. VOC loss during periods of worker access

could be minimized by restricting access opening size and by maintaining sufficient ventilation to contain VOC. Where cemented rubber components are allowed to dry on a conveyor after cement is applied, enclosed conveyors could be employed to contain VOC emitted from cemented rubber. The length of conveyor enclosed would depend upon conveyor speed and the time required to contain VOC emitted. Analysis of evaporation rates has shown that about 90 percent of VOC applied to rubber components is emitted within 30 seconds after application. Other design features to minimize VOC loss, such as vapor loss seals attached to a switching damper, could also improve overall system efficiency. Cement tanks could be covered during periods of non-use. Desorbed carbon beds could be air dried and cooled between cycles. These improvements in operating practices would improve overall system efficiency. VOC loss due to absorption is the only area in which improvements in design and operating practices would have little or no effect.

Several sources of information were used to establish the level of control that could be achieved by emission reduction systems in the rubber tire industry. Information was obtained from: (1) Available technical literature concerning emission reduction systems applicable for the control of VOC emissions in the rubber industry; (2) hood and enclosure design parameters from *Industrial Ventilation: A Manual of Recommended Practice;* (3) VOC use and process information supplied by the rubber tire industry; (4) visits to rubber tire manufacturing plants; (5) results of emission measurements and materials balance tests conducted by EPA; and (6) results of tests of VOC absorption by rubber conducted by industry.

Thermal and catalytic incinerators are effective VOC emission control devices for the types of solvents used in rubber tire manufacturing operations. A thermal incinerator operating at 870°C (1600°F) with 3/4 second residence time will typically achieve 98 percent VOC reduction efficiency or 20 parts per million on a continuous basis. A catalytic incinerator can be designed to achieve a 98 percent emission reduction efficiency on a continuous basis. In both cases, primary heat recovery should be employed to reduce operating costs.

Carbon absorbers have been demonstrated in the rubber processing industry, the pressure sensitive tape and label industry, and in other industries to achieve better than 95 percent removal of VOC emissions on a continuous basis when applied to exhaust gas streams similar to those generated in the rubber tire industry. Steam is usually employed for carbon bed regeneration, although any hot, non-reactive gas may be used.

The overall degree of continuous emission reduction achieved is not only a function of control device efficiency, but also of capture efficiency. A capture system contains VOC vapors at the emission source and directs them to the control device. VOC emissions from rubber tire plant operations result primarily from two activities: (1) application of cement or spray to rubber components; and (2) evaporation of VOC from cement or spray applied to a rubber component. Effective capture of VOC must account for both of these sources of VOC emissions.

Industry-supplied data show that at an undertread cementing operation about 70 percent of total emission is attributable to evaporation of VOC from application equipment, and about 30 percent is attributable to evaporation of VOC from rubber component surfaces. Similar data for tread end cementing and green tire spraying show that about 80 percent of total emissions is attributable to evaporation of VOC from application equipment, and about 20 percent is attributable to evaporation of VOC from rubber component surfaces. No such data are available to show a ratio for sidewall cementing or bead cementing. However, since sidewall cementing is a process very similar to undertread cementing, the ratios for these processes should be similar. Both tread end cementing and bead cementing involve the application of cement to relatively small surface areas. Therefore, EPA estimates that the ratio for bead cementing resembles the 80:20 ratio for tread end cementing.

To approach total vapor collection, a completely sealed enclosure of the emission source would be necessary. However, completely sealed enclosures are not practical in the rubber tire industry. Some affected facilities require intermittent worker access, usually for startup, maintenance, and repair purposes, while other facilities, such as manual tread end cementing, require continual worker access to the tire component.

Capture systems for cement application areas that require only intermittent access to the equipment, such as automatic tread end cementing, undertread cementing, sidewall cementing, and roller bead cementing, could consist of enclosures containing access ports equipped with self-closing doors. The capture system currently in use at one undertread cementing operation which was discussed earlier could be adapted for use at other undertread cementing operations as well as at automatic tread end cementing and sidewall cementing. Capture efficiencies of at least 80 percent could be achieved on a continuous basis.

Capture systems for cement application areas that require constant worker access could be similar to those used on portable chipping and grinding tables or soldering tables in other industries. These enclosures provide worker access and conveyor movement through side openings and are designed to minimize pressure losses through the openings. Associated with these cement application areas are conveyors that transport the cemented component. Solvent evaporates from the component while it is on the conveyor. To achieve maximum capture efficiency, the conveyors must be enclosed to allow for capture of the evaporated solvent. Conveyor enclosures such as those used for straight-line automatic buffing would be appropriate. These enclosures consist of hoods, with hinged access doors, that surround the top, sides, and underside of the conveyor. Each end of the hood is partially covered by flaps to minimize the opening size. Capture efficiencies of such enclosures are related to the percentage of total solvent that evaporates off the component while it is inside the enclosed area; however, efficiencies of at least 80 percent could be achieved on a continuous basis. The length of the enclosure would depend on the conveyor speed and the rate of evaporation of the solvent.

Dip bead cementing and inside and outside green tire spraying operations usually consist only of a cement or spray application area. For dip bead cementing, the beads are lowered into a tank which can be enclosed and the enclosure equipped with access ports. Beads could be placed in the enclosure through access ports which would remain open only until the beads were inside. The beads could be dipped into the cement, then raised, and would remain in the enclosure for enough time to allow maximum evaporation of solvent. For inside and outside green tire spraying, spray booths are usually used for application. Tires could remain inside the booths for a sufficient time after cement application to allow for maximum evaporation. Capture efficiencies of at least 80 percent could be achieved on a continuous basis.

The most effective capture systems applicable at reasonable cost to Michelin-B operations are similar to those described above for undertread and sidewall cementing operations and can achieve at least 80 percent capture

efficiency. Capture systems for Michelin-A and Michelin-C-automatic operations must allow for continual intrusion of mechanical devices, frequent worker access, and introduction of additional tire components into both the cement application and drying areas. These features limit capture efficiency at these operations. EPA has determined that the most effective capture system applicable at reasonable cost to Michelin-A and Michelin-C-automatic operations is capable of achieving 70 percent capture efficiency.

Technology exists for new and retrofit systems to achieve emission reductions of 75 percent at undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside and outside green tire spraying, and Michelin-B operations, and of 65 percent at Michelin-A and Michelin-C-automatic operations. Control devices demonstrated in other industries, which achieve an average removal or destruction efficiency of at least 95 percent, are available and can be used in conjunction with capture systems similar to those described above to achieve these levels of overall emission reduction.

Low Solvent Use Techniques

Emission reduction in the rubber tire industry can also be achieved by reducing cement usage. For tread end cementing and for bead cementing operations, each company reporting solvent use data has demonstrated that it can achieve an emission rate of 10 g/tire without the use of an emission reduction system. Solvent use rates as low as 2 g/tire have been reported for some plants.

Most of the low solvent use rates reported for tread end cementing operations were for those where cement is applied manually. However, low solvent use rates were also reported for operations where cement is applied by automatic spray arms. Most low solvent use rates for bead cementing operations were for facilities that use rollers to apply the cement. However, low solvent use rates were also reported for facilities that use a bead dipping method. EPA identified the following good work practices as helping to achieve low solvent use rates: minimizing the surface area for openings on cement pots at manual tread end cementing stations, covering cement tanks used for bead dipping, and minimizing overspray at automatic tread end cementing stations. In EPA's judgment, any new, modified, or reconstructed tread end or bead cementing operation can use 10 g/tire or less of VOC.

Substitution of Low VOC Content Materials

Green tire spraying represents another affected facility where significant emission reduction can be achieved without the use of emission reduction systems. Water-based sprays have been substituted for organic solvent-based sprays at inside and outside green tire spraying operations in a number of plants. Uncontrolled emission rates calculated for water-based inside tire sprays ranged from zero to 1.2 g/tire; uncontrolled emission rates calculated for water-based outside sprays ranged from zero to 9.3 g/tire. Product quality considerations have been cited by industry as the reason for retaining a small amount of VOC in some water-based sprays. Emissions from water-based green tire sprays are at least 90 percent less than average uncontrolled emissions from solvent-based sprays. Water-based sprays have been widely used under conditions representative of the industry and are available to all companies.

Selection of the Regulatory Alternatives

The regulatory alternatives considered in developing the standards of performance are based on the methods available to control the VOC emissions from the rubber tire industry. The three control methods considered were emission reduction systems (capture and control technology), low solvent use techniques, and low VOC content materials were considered. Impacts calculated for the regulatory alternatives were based on the use of carbon adsorber control devices where emission reduction systems are used. The proposed standards would allow the use of other types of control devices.

Regulatory Alternative I represents the regulatory baseline. State Implementation Plan (SIP) regulations for control of VOC emissions from rubber tire manufacturing plants are expected to be based on information presented in the control techniques guideline (CTG) document "Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires" (EPA–450/ 2–78–030). Therefore, Regulatory Alternative I has been set at the level of control recommended in the CTG. Under Regulatory Alternative I, VOC emissions from undertread cementing, tread end cementing, bead cementing, and inside and outside green tire spraying operations would be reduced by an average of about 70 percent. Sidewall cementing operations and Michelin-A, Michelin-B, and Michelin-C-automatic operations were not addressed in the CTG; therefore, Regulatory Alternative I does not limit VOC emissions from these affected facilities.

Emission reduction systems could be used for all affected facilities under Regulatory Alternative I to achieve a 70 percent emission reduction efficiency. Water-based sprays could be used at inside and outside green tire spraying facilities to meet or exceed a 70 percent emission reduction for Regulatory Alternative I.

Regulatory Alternative II is based upon the use of 75 percent efficient emission reduction systems for undertread cementing, sidewall cementing, tread end cementing, and bead cementing facilities, and upon the use of water-based sprays (90 percent emission reduction) for inside and outside green tire spraying facilities.

Since Michelin-A, Michelin-B, and Michelin-C-automatic operations are believed unique to Michelin Tire Corporation, they were not included in Regulatory Alternative II. Regulation of these operations was considered separately and is discussed under the section on "Best System of Continuous Emission Reduction."

Emission reductions achievable with water-based green tire sprays are significantly greater than the reductions achievable where organic solvent-based spray VOC emissions are reduced with the use of an emission reduction system. Water-based inside and outside green tire sprays have been adequately demonstrated in the industry and are available to all companies.

Environmental Impacts

Under Regulatory Alternative I (the regulatory baseline), emissions in the fifth year from new, modified, and reconstructed affected facilities would be about 3,120 Mg/year (3,430 tons/yr). The fifth year air quality impact of Regulatory Alternative II would be a reduction of about 1,700 Mg/yr (1,870 tons/yr) from baseline emissions. This is a reduction of 55 percent from the baseline.

Under each of the regulatory alternatives there could be effluent from steam regeneration of carbon adsorption beds and from overspray of inside and outside water-based green tire sprays. The VOC used in tire manufacturing is virtually insoluble in water. Therefore, most adsorbed VOC which escapes decanting and most VOC contained in overspray from inside and outside water-based green tire sprays will volatilize rather than remain in the water. Wastewater flow in 1985 under

Regulatory Alternative I would be about 4.8 million m^3/yr (1.3 billion gal/yr). Regulatory Alternative II would not increase the wastewater flow beyond the baseline.

Under Regulatory Alternative I, solid waste generated in 1985 would be about 238,000 Mg/yr (263,000 tons/yr). Regulatory Alternative II would not increase the quantity of solid waste generated. Solid waste could result from disposal of spent carbon from carbon adsorbers. Spent carbon can be recycled for other industrial uses, incinerated or disposed of by landfilling.

Energy Impacts

Energy use for pollution control equipment is based on the use of carbon adsorbers as the control technique for both regulatory alternatives. Under Regulatory Alternative I, facilities that are built, modified, or reconstructed by 1985 would use a total of about 2.5×10^{17} joules/yr of electricity for process, non-process, and pollution control purposes. Emission reduction to the level of Regulatory Alternative II would not increase the fifth-year energy usage.

Economic Impacts

A detailed analysis of the economic impact of the regulatory alternatives on the rubber tire manufacturing industry has been developed. Price increases or alternative decreases in return on investment (ROI) were determined to be reasonable for both regulatory alternatives, even under worst case conditions. In no case do capital costs of control exceed 1 percent of total investment requirements.

Regulatory Alternative I (baseline) fifth-year cumulative capital control costs would be about $16.3 million. Fifth-year annualized control costs without solvent recovery credits would be about $4.9 million; with solvent recovery credits, annualized control costs would be about $3.3 million.

Regulatory Alternative II fifth-year cumulative capital control costs would be about $7.9 million above the baseline. Fifth-year annualized costs without solvent recovery credits would increase above the baseline figure by about $2.3 million. The increase above the baseline in fifth-year annualized costs with solvent recovery credits would be about $1.5 million. Under full cost pricing, the product price would increase by about 0.14 percent under worst case conditions. Under full cost absorption, the ROI of new radial tire manufacturing plants may decline from an assumed rate of 5 percent to 4.93 percent in the worst case. In either situation the worst case is represented by the use of a separate capture system and a carbon adsorber control device at each affected facility where control equipment is used to reduce emissions. Neither impact would inhibit industry growth or replacement.

Best Systems of Continuous Emission Reduction

Regulatory Alternative II is technically and economically feasible for all affected facilities, would achieve greater emission reduction than Regulatory Alternative I, and would cause no adverse water, solid waste, or energy impacts. Capture and control technology is available to meet Regulatory Alternative II emission reductions for undertread cementing, sidewall cementing, tread end cementing, and bead cementing. Water-based inside and outside green-tire sprays are available to all rubber tire manufacturers and are already is use by most companies at one or more plants. Water-based sprays can meet or exceed Regulatory Alternative II emission reductions. Alternative II would decrease overall VOC emissions from the affected facilities by about 55 percent below the baseline. Annualized costs without recovery credits would increase by about 47 percent; with recovery credits the increase would also be about 47 percent. The increase is due primarily to addition of sidewall cementing as an affected facility. Based on consideration of these factors, Regulatory Alternative II was judged superior to Regulatory Alternative I, and Regulatory Alternative II was used as the basis for selecting the best system of continuous emission reduction.

Data on existing plants indicate that there is a wide variation in solvent use rates (and a corresponding wide range in uncontrolled emission rates) from each type of affected facility. At some low solvent use rate, the cost of employing an emission rduction system could be unreasonably high for the amount of emission reduction achieved. Since the cost per unit of emission reduction achieved is an important factor in determining the reasonableness of control at facilities with low uncontrolled emissions, the Agency considered requiring less efficient emission reduction at facilities with low solvent use rates and/or establishing solvent use cutoffs, below which no level of control would be required. These choices would be considered if, indeed, there was a solvent use rate at which the control costs were judged to be unreasonably high when compared to the emmission reduction.

As a first step in the Agency's determination, annualized costs of applying a 75 percent efficient emission reduction system were calculated for the range of solvent use rates (numbers equal to the uncontrolled emission rates) at undertread cementing, sidewall cementing, tread end cementing, and bead cementing facilities. Annualized costs per megagram of VOC emission reduction were then plotted across the range of solvent use rates. (See Figures 8-1 and 8-2 in the BID.) It was assumed that a separate capture system and control device would be used for each operation and that flow rates and capital costs for each operation are constant over the entire range of solvent use rates. These costs do not represent the actual amounts of money spent for any particular plant. Rather, the costs are estimates which represent additional lines and plants likely to be built. The costs of VOC emission reduction systems will vary according to production rate, production equipment, plant layout, geographic location, and company preferences and policies.

As was expected, the annualized cost per megagram of emission reduction increases as the solvent use rate decreases. For solvent use rates above 50 grams per tire (g/tire), the total annualized costs for a carbon adsorber, assuming recovery credits, would be about $400 per megagram of VOC emissions reduced. As the solvent use rate decreases, through changes in process and manufacturing techniques, from 50 to 25 g/tire, the costs gradually increase to about $1250 per megagram. From 25 to 15 g/tire costs begin rising at a more rapid rate. However, there is no point on the curve at which a sharp upward swing is distinguishable. In the 25 to 15 g/tire range, costs begin to exceed $2,000 per megagram. Based on VOC emission control costs in other industries regulated by standards of performance, costs above $2,000 per megagram are generally considered to be unreasonably high (although, in some instances, there may be overriding considerations that affect the determination of reasonable cost).

To reduce the cost per megagram of pollutant removed for facilities within the 25 to 15 g/tire range, the Agency considered less effective and less costly emission reduction systems for those facilities. However, systems which are less than 75 percent efficient are not significantly lower in cost than 75 percent efficient systems. Consequently, requiring a level of control less than 75 percent efficient for facilities between 25 and 15 g/tire would not bring the cost per megagram significantly below the level generally considered unreasonably high.

To identify a cutoff point between 25 and 15 g/tire, the Agency considered other cost-related factors in selecting the exact cutoff. Specifically, the Agency considered the additional cost savings that would be achieved by establishing a cutoff at 25 g/tire rather than 15 g/tire. These cost savings are associated with: conservation of energy required to operate these systems, conservation of resources required for their operation and maintenance, and the encouragement of solvent conservation at facilities that can, or may develop methods to, reduce solvent usage to meet the cutoff limits rather than install capture and control systems. In light of these benefits and the general view that the Agency should set standards that encourage development of inherently low-emitting processes, and in the absence of a clearly identified VOC use rate at which the control costs per megagram reduction are clearly unreasonable, the Administrator is proposing 25 g/tire as the cutoff solvent use rate for undertread cementing and sidewall cementing facilities. While solvent use rates average about 63 g/tire for existing undertread cementing and 41 g/tire for existing sidewall cementing facilities, solvent use rates below 25 g/tire have been reported for each of these operations. The costs to reduce emissions by 75 percent at solvent use rates above 25 g/tire are considered reasonable, and 25 g/tire is an appropriate cutoff point considering both the benefits which accrue and the rapidly increasing cost per megagram associated with control at solvent use rates below 25 g/tire. Therefore, the best system of continuous emission reduction for undertread and sidewall cementing operations is an emission reduction system that achieves 75 percent overall control for facilities that use more than 25 g/tire, and low solvent techniques for facilities that use 25 g/tire or less. The 75 percent efficient emission reduction system was based on an 80 percent efficient capture system and a 95 percent efficient carbon adsorber control device. The proposed standards would also allow use of other types of control devices, and any combination of capture and control efficiencies that result in at least a 75 percent overall emission reduction.

A similar analysis was done for tread end cementing and bead cementing, and cutoffs of 25 and 20 g/tire respectively were selected. (See Figures 8-3 to 8-5 in BID.) These cutoffs were higher than VOC use rates for most existing tread end cementing and bead cementing facilities. No new tread end or bead cementing operations are expected to use more than the 25 or 20 g/tire cutoffs. Therefore, requiring those tread end cementing or bead cementing operations that use more than the cutoff amounts of VOC to reduce emissions by 75 percent would achieve no emission reduction. However, an alternative means of minimizing emissions has been adequately demonstrated to achieve effective control at tread end cementing and bead cementing facilities. Industry-supplied solvent use data show that each company has at least one plant that uses 10 g/tire or less at each of these operations. Further, many existing plants already use substantially less than 10 g/tire. Emission rates of 10 g/tire, or less, could be achieved without the use of emission reduction systems. A 10 g/tire emission limit for all tread end cementing and bead cementing operations would result in a greater nationwide emission reduction than would be achieved by requiring installation of a 75 percent efficient emission reduction system for those facilities that use more than the cutoff amounts of VOC. Since no emission reduction systems would be used, capital and operating costs, and water, solid waste and energy impacts would be reduced. For the above reasons, the best system of continuous emission reduction for tread end and bead cementing operations is low-solvent techniques that use less than 10 g/tire.

The best system of continuous emission reduction for inside green tire spraying and outside green tire spraying operations is water-based green tire sprays. Water-based green tire sprays result in lower emissions than when solvent-based sprays are used in conjunction with emission reduction systems.

Choosing low solvent use techniques as the best system of continuous emission reduction for tread cementing and bead cementing operations, and setting 25 g/tire cutoffs for undertread cementing and sidewall cementing operations result in the impacts of the proposed standards being different from the impacts of Regulatory Alternative II. Under the proposed standards, baseline emissions from undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying would be reduced by about 1,430 Mg (1,570 tons) in the fifth year, a 46 percent reduction. This emission reduction would be about 9 percent less than the emission reduction estimated for these affected facilities under Regulatory Alternative II. The amounts of energy used, and water pollution and solid waste generated under the proposed standards would be less than under Regulatory Alternative II.

Because the proposed standards would not in most cases require the use of emission reduction systems for affected facilities other than undertread cementing and sidewall cementing, capital and annualized costs would be less than those for Regulatory Alternatives I and II. Fifth-year cumulative capital costs would be about $10.8 million above uncontrolled levels, about 34 percent less than the baseline and about 55 percent less than Regulatory Alternative II. Annualized costs in the fifth year without recovery credits would be about $3.4 million above uncontrolled levels; with recovery credits the fifth-year annualized cost would be about $1.5 million above uncontrolled levels. These annualized costs represent reductions from the baseline of about 31 percent and 54 percent, respectively; they represent cost reductions from Regulatory Alternative II of about 53 percent and 69 percent, respectively. The average product price would rise about 0.26 percent above uncontrolled levels in the worst case. The product price is not expected to increase above baseline levels. Under full cost absorption, using uncontrolled levels as a base comparison, the ROI would decrease from an assumed rate of 5.17 percent to about 5.04 percent under worst case conditions. The ROI is not expected to decrease below baseline levels.

Based on EPA's analysis of information submitted by Michelin Tire Corporation, the Agency has determined the best technological system of continuous emission reduction for the Michelin-B operation to be a VOC capture system and carbon adsorber control device that will achieve a 75 percent overall emission reduction. For Michelin-A and Michelin-C-automatic operations, EPA has determined the best technological system of emission reduction to be a VOC capture system and carbon adsorber control device that will achieve a 65 percent overall emission reduction. EPA has determined that these systems are available at reasonable cost and do not impose unreasonable adverse water, solid waste, or energy impacts. The proposed standards would also allow the use of control devices other than carbon adsorbers.

Selection of Format of Proposed Standard

Concentration, mass units, and efficiency were considered as formats for the proposed standards. A concentration format for the proposed

could be minimized by restricting access opening size and by maintaining sufficient ventilation to contain VOC. Where cemented rubber components are allowed to dry on a conveyor after cement is applied, enclosed conveyors could be employed to contain VOC emitted from cemented rubber. The length of conveyor enclosed would depend upon conveyor speed and the time required to contain VOC emitted. Analysis of evaporation rates has shown that about 90 percent of VOC applied to rubber components is emitted within 30 seconds after application. Other design features to minimize VOC loss, such as vapor loss seals attached to a switching damper, could also improve overall system efficiency. Cement tanks could be covered during periods of non-use. Desorbed carbon beds could be air dried and cooled between cycles. These improvements in operating practices would improve overall system efficiency. VOC loss due to absorption is the only area in which improvements in design and operating practices would have little or no effect.

Several sources of information were used to establish the level of control that could be achieved by emission reduction systems in the rubber tire industry. Information was obtained from: (1) Available technical literature concerning emission reduction systems applicable for the control of VOC emissions in the rubber industry; (2) hood and enclosure design parameters from *Industrial Ventilation: A Manual of Recommended Practice;* (3) VOC use and process information supplied by the rubber tire industry; (4) visits to rubber tire manufacturing plants; (5) results of emission measurements and materials balance tests conducted by EPA; and (6) results of tests of VOC absorption by rubber conducted by industry.

Thermal and catalytic incinerators are effective VOC emission control devices for the types of solvents used in rubber tire manufacturing operations. A thermal incinerator operating at 870°C (1600°F) with 3/4 second residence time will typically achieve 98 percent VOC reduction efficiency or 20 parts per million on a continuous basis. A catalytic incinerator can be designed to achieve a 98 percent emission reduction efficiency on a continuous basis. In both cases, primary heat recovery should be employed to reduce operating costs.

Carbon absorbers have been demonstrated in the rubber processing industry, the pressure sensitive tape and label industry, and in other industries to achieve better than 95 percent removal of VOC emissions on a continuous basis when applied to exhaust gas streams similar to those generated in the rubber tire industry. Steam is usually employed for carbon bed regeneration, although any hot, non-reactive gas may be used.

The overall degree of continuous emission reduction achieved is not only a function of control device efficiency, but also of capture efficiency. A capture system contains VOC vapors at the emission source and directs them to the control device. VOC emissions from rubber tire plant operations result primarily from two activities: (1) application of cement or spray to rubber components; and (2) evaporation of VOC from cement or spray applied to a rubber component. Effective capture of VOC must account for both of these sources of VOC emissions.

Industry-supplied data show that at an undertread cementing operation about 70 percent of total emission is attributable to evaporation of VOC from application equipment, and about 30 percent is attributable to evaporation of VOC from rubber component surfaces. Similar data for tread end cementing and green tire spraying show that about 80 percent of total emissions is attributable to evaporation of VOC from application equipment, and about 20 percent is attributable to evaporation of VOC from rubber component surfaces. No such data are available to show a ratio for sidewall cementing or bead cementing. However, since sidewall cementing is a process very similar to undertread cementing, the ratios for these processes should be similar. Both tread end cementing and bead cementing involve the application of cement to relatively small surface areas. Therefore, EPA estimates that the ratio for bead cementing resembles the 80:20 ratio for tread end cementing.

To approach total vapor collection, a completely sealed enclosure of the emission source would be necessary. However, completely sealed enclosures are not practical in the rubber tire industry. Some affected facilities require intermittent worker access, usually for startup, maintenance, and repair purposes, while other facilities, such as manual tread end cementing, require continual worker access to the tire component.

Capture systems for cement application areas that require only intermittent access to the equipment, such as automatic tread end cementing, undertread cementing, sidewall cementing, and roller bead cementing, could consist of enclosures containing access ports equipped with self-closing doors. The capture system currently in use at one undertread cementing operation which was discussed earlier could be adapted for use at other undertread cementing operations as well as at automatic tread end cementing and sidewall cementing. Capture efficiencies of at least 80 percent could be achieved on a continuous basis.

Capture systems for cement application areas that require constant worker access could be similar to those used on portable chipping and grinding tables or soldering tables in other industries. These enclosures provide worker access and conveyor movement through side openings and are designed to minimize pressure losses through the openings. Associated with these cement application areas are conveyors that transport the cemented component. Solvent evaporates from the component while it is on the conveyor. To achieve maximum capture efficiency, the conveyors must be enclosed to allow for capture of the evaporated solvent. Conveyor enclosures such as those used for straight-line automatic buffing would be appropriate. These enclosures consist of hoods, with hinged access doors, that surround the top, sides, and underside of the conveyor. Each end of the hood is partially covered by flaps to minimize the opening size. Capture efficiencies of such enclosures are related to the percentage of total solvent that evaporates off the component while it is inside the enclosed area; however, efficiencies of at least 80 percent could be achieved on a continuous basis. The length of the enclosure would depend on the conveyor speed and the rate of evaporation of the solvent.

Dip bead cementing and inside and outside green tire spraying operations usually consist only of a cement or spray application area. For dip bead cementing, the beads are lowered into a tank which can be enclosed and the enclosure equipped with access ports. Beads could be placed in the enclosure through access ports which would remain open only until the beads were inside. The beads could be dipped into the cement, then raised, and would remain in the enclosure for enough time to allow maximum evaporation of solvent. For inside and outside green tire spraying, spray booths are usually used for application. Tires could remain inside the booths for a sufficient time after cement application to allow for maximum evaporation. Capture efficiencies of at least 80 percent could be achieved on a continuous basis.

The most effective capture systems applicable at reasonable cost to Michelin-B operations are similar to those described above for undertread and sidewall cementing operations and can achieve at least 80 percent capture

efficiency. Capture systems for Michelin-A and Michelin-C-automatic operations must allow for continual intrusion of mechanical devices, frequent worker access, and introduction of additional tire components into both the cement application and drying areas. These features limit capture efficiency at these operations. EPA has determined that the most effective capture system applicable at reasonable cost to Michelin-A and Michelin-C-automatic operations is capable of achieving 70 percent capture efficiency.

Technology exists for new and retrofit systems to achieve emission reductions of 75 percent at undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside and outside green tire spraying, and Michelin-B operations, and of 65 percent at Michelin-A and Michelin-C-automatic operations. Control devices demonstrated in other industries, which achieve an average removal or destruction efficiency of at least 95 percent, are available and can be used in conjunction with capture systems similar to those described above to achieve these levels of overall emission reduction.

Low Solvent Use Techniques

Emission reduction in the rubber tire industry can also be achieved by reducing cement usage. For tread end cementing and for bead cementing operations, each company reporting solvent use data has demonstrated that it can achieve an emission rate of 10 g/tire without the use of an emission reduction system. Solvent use rates as low as 2 g/tire have been reported for some plants.

Most of the low solvent use rates reported for tread end cementing operations were for those where cement is applied manually. However, low solvent use rates were also reported for operations where cement is applied by automatic spray arms. Most low solvent use rates for bead cementing operations were for facilities that use rollers to apply the cement. However, low solvent use rates were also reported for facilities that use a bead dipping method. EPA identified the following good work practices as helping to achieve low solvent use rates: minimizing the surface area for openings on cement pots at manual tread end cementing stations, covering cement tanks used for bead dipping, and minimizing overspray at automatic tread end cementing stations. In EPA's judgment, any new, modified, or reconstructed tread end or bead cementing operation can use 10 g/tire or less of VOC.

Substitution of Low VOC Content Materials

Green tire spraying represents another affected facility where significant emission reduction can be achieved without the use of emission reduction systems. Water-based sprays have been substituted for organic solvent-based sprays at inside and outside green tire spraying operations in a number of plants. Uncontrolled emission rates calculated for water-based inside tire sprays ranged from zero to 1.2 g/tire; uncontrolled emission rates calculated for water-based outside sprays ranged from zero to 9.3 g/tire. Product quality considerations have been cited by industry as the reason for retaining a small amount of VOC in some water-based sprays. Emissions from water-based green tire sprays are at least 90 percent less than average uncontrolled emissions from solvent-based sprays. Water-based sprays have been widely used under conditions representative of the industry and are available to all companies.

Selection of the Regulatory Alternatives

The regulatory alternatives considered in developing the standards of performance are based on the methods available to control the VOC emissions from the rubber tire industry. The three control methods considered were emission reduction systems (capture and control technology), low solvent use techniques, and low VOC content materials were considered. Impacts calculated for the regulatory alternatives were based on the use of carbon adsorber control devices where emission reduction systems are used. The proposed standards would allow the use of other types of control devices.

Regulatory Alternative I represents the regulatory baseline. State Implementation Plan (SIP) regulations for control of VOC emissions from rubber tire manufacturing plants are expected to be based on information presented in the control techniques guideline (CTG) document "Control of Volatile Organic Emissions from Manufacture of Pneumatic Rubber Tires" (EPA–450/ 2–78–030). Therefore, Regulatory Alternative I has been set at the level of control recommended in the CTG. Under Regulatory Alternative I, VOC emissions from undertread cementing, tread end cementing, bead cementing, and inside and outside green tire spraying operations would be reduced by an average of about 70 percent. Sidewall cementing operations and Michelin-A, Michelin-B, and Michelin-C-automatic operations were not addressed in the CTG; therefore, Regulatory Alternative I does not limit VOC emissions from these affected facilities.

Emission reduction systems could be used for all affected facilities under Regulatory Alternative I to achieve a 70 percent emission reduction efficiency. Water-based sprays could be used at inside and outside green tire spraying facilities to meet or exceed a 70 percent emission reduction for Regulatory Alternative I.

Regulatory Alternative II is based upon the use of 75 percent efficient emission reduction systems for undertread cementing, sidewall cementing, tread end cementing, and bead cementing facilities, and upon the use of water-based sprays (90 percent emission reduction) for inside and outside green tire spraying facilities.

Since Michelin-A, Michelin-B, and Michelin-C-automatic operations are believed unique to Michelin Tire Corporation, they were not included in Regulatory Alternative II. Regulation of these operations was considered separately and is discussed under the section on "Best System of Continuous Emission Reduction."

Emission reductions achievable with water-based green tire sprays are significantly greater than the reductions achievable where organic solvent-based spray VOC emissions are reduced with the use of an emission reduction system. Water-based inside and outside green tire sprays have been adequately demonstrated in the industry and are available to all companies.

Environmental Impacts

Under Regulatory Alternative I (the regulatory baseline), emissions in the fifth year from new, modified, and reconstructed affected facilities would be about 3,120 Mg/year (3,430 tons/yr). The fifth year air quality impact of Regulatory Alternative II would be a reduction of about 1,700 Mg/yr (1,870 tons/yr) from baseline emissions. This is a reduction of 55 percent from the baseline.

Under each of the regulatory alternatives there could be effluent from steam regeneration of carbon adsorption beds and from overspray of inside and outside water-based green tire sprays. The VOC used in tire manufacturing is virtually insoluble in water. Therefore, most adsorbed VOC which escapes decanting and most VOC contained in overspray from inside and outside water-based green tire sprays will volatilize rather than remain in the water. Wastewater flow in 1985 under

Regulatory Alternative I would be about 4.8 million m^3/yr (1.3 billion gal/yr). Regulatory Alternative II would not increase the wastewater flow beyond the baseline.

Under Regulatory Alternative I, solid waste generated in 1985 would be about 238,000 Mg/yr (263,000 tons/yr). Regulatory Alternative II would not increase the quantity of solid waste generated. Solid waste could result from disposal of spent carbon from carbon adsorbers. Spent carbon can be recycled for other industrial uses, incinerated or disposed of by landfilling.

Energy Impacts

Energy use for pollution control equipment is based on the use of carbon adsorbers as the control technique for both regulatory alternatives. Under Regulatory Alternative I, facilities that are built, modified, or reconstructed by 1985 would use a total of about 2.5×10^{17} joules/yr of electricity for process, non-process, and pollution control purposes. Emission reduction to the level of Regulatory Alternative II would not increase the fifth-year energy usage.

Economic Impacts

A detailed analysis of the economic impact of the regulatory alternatives on the rubber tire manufacturing industry has been developed. Price increases or alternative decreases in return on investment (ROI) were determined to be reasonable for both regulatory alternatives, even under worst case conditions. In no case do capital costs of control exceed 1 percent of total investment requirements.

Regulatory Alternative I (baseline) fifth-year cumulative capital control costs would be about $16.3 million. Fifth-year annualized control costs without solvent recovery credits would be about $4.9 million; with solvent recovery credits, annualized control costs would be about $3.3 million.

Regulatory Alternative II fifth-year cumulative capital control costs would be about $7.9 million above the baseline. Fifth-year annualized costs without solvent recovery credits would increase above the baseline figure by about $2.3 million. The increase above the baseline in fifth-year annualized costs with solvent recovery credits would be about $1.5 million. Under full cost pricing, the product price would increase by about 0.14 percent under worst case conditions. Under full cost absorption, the ROI of new radial tire manufacturing plants may decline from an assumed rate of 5 percent to 4.93 percent in the worst case. In either situation the worst case is represented by the use of a separate capture system and a carbon adsorber control device at each affected facility where control equipment is used to reduce emissions. Neither impact would inhibit industry growth or replacement.

Best Systems of Continuous Emission Reduction

Regulatory Alternative II is technically and economically feasible for all affected facilities, would achieve greater emission reduction than Regulatory Alternative I, and would cause no adverse water, solid waste, or energy impacts. Capture and control technology is available to meet Regulatory Alternative II emission reductions for undertread cementing, sidewall cementing, tread end cementing, and bead cementing. Water-based inside and outside green tire sprays are available to all rubber tire manufacturers and are already is use by most companies at one or more plants. Water-based sprays can meet or exceed Regulatory Alternative II emission reductions. Alternative II would decrease overall VOC emissions from the affected facilities by about 55 percent below the baseline. Annualized costs without recovery credits would increase by about 47 percent; with recovery credits the increase would also be about 47 percent. The increase is due primarily to addition of sidewall cementing as an affected facility. Based on consideration of these factors, Regulatory Alternative II was judged superior to Regulatory Alternative I, and Regulatory Alternative II was used as the basis for selecting the best system of continuous emission reduction.

Data on existing plants indicate that there is a wide variation in solvent use rates (and a corresponding wide range in uncontrolled emission rates) from each type of affected facility. At some low solvent use rate, the cost of employing an emission rduction system could be unreasonably high for the amount of emission reduction achieved. Since the cost per unit of emission reduction achieved is an important factor in determining the reasonableness of control at facilities with low uncontrolled emissions, the Agency considered requiring less efficient emission reduction at facilities with low solvent use rates and/or establishing solvent use cutoffs, below which no level of control would be required. These choices would be considered if, indeed, there was a solvent use rate at which the control costs were judged to be unreasonably high when compared to the emmission reduction.

As a first step in the Agency's determination, annualized costs of applying a 75 percent efficient emission reduction system were calculated for the range of solvent use rates (numbers equal to the uncontrolled emission rates) at undertread cementing, sidewall cementing, tread end cementing, and bead cementing facilities. Annualized costs per megagram of VOC emission reduction were then plotted across the range of solvent use rates. (See Figures 8-1 and 8-2 in the BID.) It was assumed that a separate capture system and control device would be used for each operation and that flow rates and capital costs for each operation are constant over the entire range of solvent use rates. These costs do not represent the actual amounts of money spent for any particular plant. Rather, the costs are estimates which represent additional lines and plants likely to be built. The costs of VOC emission reduction systems will vary according to production rate, production equipment, plant layout, geographic location, and company preferences and policies.

As was expected, the annualized cost per megagram of emission reduction increases as the solvent use rate decreases. For solvent use rates above 50 grams per tire (g/tire), the total annualized costs for a carbon adsorber, assuming recovery credits, would be about $400 per megagram of VOC emissions reduced. As the solvent use rate decreases, through changes in process and manufacturing techniques, from 50 to 25 g/tire, the costs gradually increase to about $1250 per megagram. From 25 to 15 g/tire costs begin rising at a more rapid rate. However, there is no point on the curve at which a sharp upward swing is distinguishable. In the 25 to 15 g/tire range, costs begin to exceed $2,000 per megagram. Based on VOC emission control costs in other industries regulated by standards of performance, costs above $2,000 per megagram are generally considered to be unreasonably high (although, in some instances, there may be overriding considerations that affect the determination of reasonable cost).

To reduce the cost per megagram of pollutant removed for facilities within the 25 to 15 g/tire range, the Agency considered less effective and less costly emission reduction systems for those facilities. However, systems which are less than 75 percent efficient are not significantly lower in cost than 75 percent efficient systems. Consequently, requiring a level of control less than 75 percent efficient for facilities between 25 and 15 g/tire would not bring the cost per megagram significantly below the level generally considered unreasonably high.

To identify a cutoff point betwen 25 and 15 g/tire, the Agency considered other cost-related factors in selecting the exact cutoff. Specifically, the Agency considered the additional cost savings that would be achieved by establishing a cutoff at 25 g/tire rather than 15 g/tire. These cost savings are associated with: conservation of energy required to operate these systems, conservation of resources required for their operation and maintenance, and the encouragement of solvent conservation at facilities that can, or may develop methods to, reduce solvent usage to meet the cutoff limits rather than install capture and control systems. In light of these benefits and the general view that the Agency should set standards that encourage development of inherently low-emitting processes, and in the absence of a clearly identified VOC use rate at which the control costs per megagram reduction are clearly unreasonable, the Administrator is proposing 25 g/tire as the cutoff solvent use rate for undertread cementing and sidewall cementing facilities. While solvent use rates average about 63 g/tire for existing undertread cementing and 41 g/tire for existing sidewall cementing facilities, solvent use rates below 25 g/tire have been reported for each of these operations. The costs to reduce emissions by 75 percent at solvent use rates above 25 g/tire are considered reasonable, and 25 g/tire is an appropriate cutoff point considering both the benefits which accrue and the rapidly increasing cost per megagram associated with control at solvent use rates below 25 g/tire. Therefore, the best system of continuous emission reduction for undertread and sidewall cementing operations is an emission reduction system that achieves 75 percent overall control for facilities that use more than 25 g/tire, and low solvent techniques for facilities that use 25 g/tire or less. The 75 percent efficient emission reduction system was based on an 80 percent efficient capture system and a 95 percent efficient carbon adsorber control device. The proposed standards would also allow use of other types of control devices, and any combination of capture and control efficiencies that result in at least a 75 percent overall emission reduction.

A similar analysis was done for tread end cementing and bead cementing, and cutoffs of 25 and 20 g/tire respectively were selected. (See Figures 8-3 to 8-5 in BID.) These cutoffs were higher than VOC use rates for most existing tread end cementing and bead cementing facilities. No new tread end or bead cementing operations are expected to use more than the 25 or 20 g/tire cutoffs. Therefore, requiring those tread end cementing or bead cementing operations that use more than the cutoff amounts of VOC to reduce emissions by 75 percent would achieve no emission reduction. However, an alternative means of minimizing emissions has been adequately demonstrated to achieve effective control at tread end cementing and bead cementing facilities. Industry-supplied solvent use data show that each company has at least one plant that uses 10 g/tire or less at each of these operations. Further, many existing plants already use substantially less than 10 g/tire. Emission rates of 10 g/tire, or less, could be achieved without the use of emission reduction systems. A 10 g/tire emission limit for all tread end cementing and bead cementing operations would result in a greater nationwide emission reduction than would be achieved by requiring installation of a 75 percent efficient emission reduction system for those facilities that use more than the cutoff amounts of VOC. Since no emission reduction systems would be used, capital and operating costs, and water, solid waste and energy impacts would be reduced. For the above reasons, the best system of continuous emission reduction for tread end and bead cementing operations is low-solvent techniques that use less than 10 g/tire.

The best system of continuous emission reduction for inside green tire spraying and outside green tire spraying operations is water-based green tire sprays. Water-based green tire sprays result in lower emissions than when solvent-based sprays are used in conjunction with emission reduction systems.

Choosing low solvent use techniques as the best system of continuous emission reduction for tread cementing and bead cementing operations, and setting 25 g/tire cutoffs for undertread cementing and sidewall cementing operations result in the impacts of the proposed standards being different from the impacts of Regulatory Alternative II. Under the proposed standards, baseline emissions from undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying would be reduced by about 1,430 Mg (1,570 tons) in the fifth year, a 46 percent reduction. This emission reduction would be about 9 percent less than the emission reduction estimated for these affected facilities under Regulatory Alternative II. The amounts of energy used, and water pollution and solid waste generated under the proposed standards would be less than under Regulatory Alternative II.

Because the proposed standards would not in most cases require the use of emission reduction systems for affected facilities other than undertread cementing and sidewall cementing, capital and annualized costs would be less than those for Regulatory Alternatives I and II. Fifth-year cumulative capital costs would be about $10.8 million above uncontrolled levels, about 34 percent less than the baseline and about 55 percent less than Regulatory Alternative II. Annualized costs in the fifth year without recovery credits would be about $3.4 million above uncontrolled levels; with recovery credits the fifth-year annualized cost would be about $1.5 million above uncontrolled levels. These annualized costs represent reductions from the baseline of about 31 percent and 54 percent, respectively; they represent cost reductions from Regulatory Alternative II of about 53 percent and 69 percent, respectively. The average product price would rise about 0.26 percent above uncontrolled levels in the worst case. The product price is not expected to increase above baseline levels. Under full cost absorption, using uncontrolled levels as a base comparison, the ROI would decrease from an assumed rate of 5.17 percent to about 5.04 percent under worst case conditions. The ROI is not expected to decrease below baseline levels.

Based on EPA's analysis of information submitted by Michelin Tire Corporation, the Agency has determined the best technological system of continuous emission reduction for the Michelin-B operation to be a VOC capture system and carbon adsorber control device that will achieve a 75 percent overall emission reduction. For Michelin-A and Michelin-C-automatic operations, EPA has determined the best technological system of emission reduction to be a VOC capture system and carbon adsorber control device that will achieve a 65 percent overall emission reduction. EPA has determined that these systems are available at reasonable cost and do not impose unreasonable adverse water, solid waste, or energy impacts. The proposed standards would also allow the use of control devices other than carbon adsorbers.

Selection of Format of Proposed Standard

Concentration, mass units, and efficiency were considered as formats for the proposed standards. A concentration format for the proposed

standards would limit the amount of VOC per unit volume of exhaust gas discharged into the atmosphere but not the total mass of VOC discharged. The advantage of the concentration format is that the test method would not require measurement of gas flow or composition of the solvent. The primary disadvantage of using a concentration format is that solvent application rates (hence emissions) are variable, and, as a result, vapor concentrations also vary widely. A further complication is the assertion by some industry representatives that air flow rates affect product quality, and companies may therefore differ in their ventilation specifications. For these reasons, concentration units were rejected as a format for the proposed standards.

A second option is to express the proposed standards in terms that limit VOC emissions to a maximum allowable mass per unit of production. A mass standard for this industry could be expressed in grams of VOC emitted per tire processed (g/tire). A g/tire standard is suitable where low solvent use techniques are employed to minimize VOC emissions at tread end cementing and bead cementing facilities, and where water-based sprays are employed to minimize VOC emissions at inside and outside green tire spraying facilities. As a result, the proposed standards for tread end cementing, bead cementing, and green tire spraying facilities are expressed as grams of VOC emitted per tire processed (g/tire).

Gram per tire emission limits were not considered to be appropriate where the best system of continuous emission reduction is an emission reduction system. Establishing g/tire emission limits based on reduction from the highest uncontrolled emission rates would ensure achievability of the standards but would require installation of the best system of continuous emission reduction only on the few facilities with the highest emission rates. Facilities with lower uncontrolled rates could achieve the standards without using best control technology. Gram per tire emission limits based on reduction from less than the highest (e.g., the average) uncontrolled emission rates could result in limits that may not be achievable by all facilities, especially those with the highest uncontrolled emissions. Further, some industry representatives expressed concern at the December 2, 1980, meeting of the National Air Pollution Control Techniques Advisory Committee that gram per tire emission limits based on a reduction from even the highest reported emission rate may not be achievable. This concern was based on the possibility that a new facilty could have an uncontrolled emission rate higher than those reported for existing facilities. These problems could be overcome by choosing an efficiency format, which would reflect the use of capture and control systems irrespective of the uncontrolled emission rate at the facility. Therefore, an efficiency format was chosen for the standards for undertread and sidewall cementing operations that use more than 25 g/tire and for Michelin-A, Michelin-B, and Michelin-C-automatic operations. To ensure that all aspects of the issue have been considered adequately, the Agency requests comments from interested parties about the recommended percent reduction format.

Selection of Numerical Emission Limits

Based on the best systems of continuous emission reduction, the proposed standards consist of the following numerical emission limits. Each undertread cementing operation and each sidewall cementing operation where more than 25 grams of VOC are used per tire would be required to reduce emissions by at least 75 percent. Undertread cementing and sidewall cementing operations that use less than 25 g/tire would not be required to install emission reduction systems. Each tread end and bead cementing facility would be required to limit emissions to no more than 10 g/tire. Each inside green tire spray operation would be required to limit emissions to no more than 1.2 g/tire, and each outside green tire spray operation would be required to limit emissions to no more than 9.3 g/tire. Each Michelin-B operation would be required to reduce emissions by at least 75 percent. Each Michelin-A operation and each Michelin-C-automatic operation would be required to reduce emissions by at least 65 percent. As stated above, these emission limits reflect application of the best demonstrated system of emission reduction at each affected facility in a rubber tire manufacturing plant.

Rubber tire industry representatives have requested EPA to consider adding a provision to the proposed standards which would allow a plant owner or operator the option of meeting an emission limit calculated for a group of individual affected facilities rather than individual limits for each affected facility. The emission limit for the group would be calculated by combining prescribed emission limits for individual affected facilities and, for purposes of the following discussion, is termed an NSPS compliance bubble, i.e., a tradeoff of emissions among affected facilities for compliance purposes.

EPA believes a compliance tradeoff for rubber tire manufacturing may be appropriate and may be consistent with Section 111 of the Clean Air Act and is considering incorporating such a tradeoff in the standards before promulgation. Standards currently proposed or promulgated under Section 111 of the Act do not contain such a provision. EPA is in the early stages of evaluating a general policy for Section 111 standards which, if adopted, would provide for compliance tradeoffs where determined appropriate for plants containing multiple affected facilities. Until EPA establishes a policy for Section 111 standards in general, the Agency is not prepared to propose such a policy in the rubber tire standard. However, EPA will make a decision on this policy before the rubber tire standard is promulgated. Therefore, EPA is requesting comments on the use of a compliance tradeoff as a part of this package. It is anticipated that any compliance tradeoff incorporated into the rubber tire standard would allow aggregation of individual emission limits only for those facilities within a plant which are subject to the standards (newly constructed, modified, or reconstructed) and which are present in that specific plant.

Modification/Reconstruction Considerations

Modification, as defined in § 60.14 of Chapter I, Title 40 of the Code of Federal Regulations (CFR), may occur when any physical or operational change to an existing facility results in an increase in emission rate to the atmosphere of any pollutant to which a standard applies. However, there are several changes that result in increased emission rates which are exempt from the modification provision. Once such provision is for a production rate increase that is accomplished without a "capital expenditure" as defined in § 60.2.

The production rate of a rubber tire manufacturing plant is usually directly related to the capacities of the tire building or curing press operations, which are not subject to the proposed standards. Other operations, including operations selected as affected facilities, normally run at less than full capacity, and their production rates can usually be increased up to full capacity without a capital expenditure. Most changes expected to occur would be of this nature. As a result, few, if any, modifications are expected.

Reconstruction, as defined in § 60.15 of Chapter I, Title 40 of the CFR, occurs

when the fixed capital cost of replacement components of an existing facility exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility and compliance is technically and economically feasible. Upon replacement of components, the Administrator will determine, on a case-by-case basis, whether a reconstruction has taken place and whether the existing facility becomes an affected facility under the NSPS.

Investigation of the rubber tire manufacturing industry has indicated that repair or rebuilding of an existing facility where costs would exceed 50 percent of the cost of replacing the facility is unusual.

Selection of Performance Test Methods

The proposed standards would require two types of performance tests, initial performance tests and monthly performance tests. Initial performance tests would be required for all affected facilities except those facilities that demonstrate compliance with the percent emission reduction requirements by meeting certain equipment specifications. These facilities would conduct an initial performance test on the control device but not on the capture system. However, the owner or operator would be required to state in the initial compliance report whether or not each capture system specification has been met. Monthly performance tests would be required for most, but not all, affected facilities.

Monthly performance tests were chosen, where practical, to ensure continual compliance. Requiring only an initial performance test would somewhat reduce the monitoring workload on the owner or operator, but would not be as useful to either the owner or operator or to the Agency for ensuring continual compliance. In addition, most of the data required for monthly performance tests are routinely collected and maintained by the source as part of production and inventory records. Performance tests that consist of costly stack testing are not required on a monthly basis in order for EPA to ensure that compliance costs are maintained at a reasonable level.

Monthly performance tests would be required to determine compliance with each of the g/tire limits. Whether or not monthly performance tests would be required to determine compliance with the percent emission reduction standards depends primarily on the type of control device used, and then on the method of demonstrating compliance. If the control device recovers VOC and compliance is demonstrated by achieving a 75 percent emission reduction, monthly performance tests would be required. If the control device recovers VOC but compliance is demonstrated by meeting the equipment specifications, monthly performance tests would not be required. If the control device destroys VOC, monthly performance tests would not be required, regardless of the method used to demonstrate compliance.

Performance test procedures for each type of affected facility vary depending on the format of the standard (g/tire or percent emission reduction) and the type of emission control device, if any, that is used. The performance test procedures are outlined below.

For each affected facility that complies with a g/tire limit, the mass of VOC emitted per tire processed for a calendar month would be determined during the initial performance test. This determination would necessitate a materials balance calculation if compliance is achieved by reducing solvent usage or by using a control device that recovers VOC. If a control device that destroys VOC is used, the determination would require a stack test.

Monthly performance tests for facilities that comply with g/tire limits would be the same as the initial performance test except for those affected facilities where a control device that destroys VOC is used. For these affected facilities, the overall emission reduction efficiency determined in the initial performance test could be used for monthly performance tests until the Administrator requests that the efficiency be redetermined, or the operating conditions of the system are changed. The rationale for this provision is that a requirement for an owner or operator to conduct monthly stack tests could result in unreasonable costs.

For each affected facility for which the owner or operator choose to use an emission reduction system with a control device that recovers VOC to meet a percent reduction requirement, the overall efficiency of the emission reduction system for a calendar month would be determined during the initial performance test. This would be done by comparing the mass of VOC recovered by the emission reduction system to the mass of VOC used at the affected facility. No stack testing would be required. Monthly performance tests would be the same as the initial performance test.

For each affected facility for which the owner or operator chooses to use an emission reduction system that destroys VOC to meet a percent reduction requirement, the overall efficiency of the emission system would be determined by a stack test performed during the initial performance test. No monthly performance test would be required. The emission reduction system efficiency would be redetermined by a stack test when requested by the Administrator or when the operating conditions of the system are changed.

Data necessary to calculate the VOC content of cement or spray material would be obtained from formulation data supplied by the manufacturer of the spray, or through the analysis of each cement or spray material by Reference Method 24 "Determination of Volatile Organic Compound Content of Paint, Varnish, Lacquer, or Related Products" or an alternative or equivalent method acceptable to the Administrator. Reference Method 24 would serve as the reference method for the calculation of the VOC content of the cement or spray materials in case of dispute.

Alternative Compliance Method

As an alternative method for demonstrating compliance with the proposed standards for undertread cementing, sidwall cementing, or Michelin-B operations, the owner or operator may elect to meet equipment specifications for capture systems used in conjunction with a 95 percent efficient control device. These specifications include enclosure of cement application and drying areas, maintenance of 100 feet per minute face velocity through each permanent opening to an enclosure, and an upper limit on the area of permanent openings to an enclosure. The Administrator has determined that meeting these specifications in conjunction with operating a 95 percent efficient control device is an acceptable means of demonstrating compliance.

An initial performance test of the control device would be required within 180 days after initial start-up of the affected facility. This test would be repeated when requested by the Administrator or when control device operating conditions are changed. The owner or operator would be required to continuously monitor the control device as described in the section on Selection of Monitoring Requirements. No monthly performance tests would be required because the cost of monthly stack tests could be unreasonable.

Neither an initial performance test nor monthly performance tests would be required for the capture system. However, the owner or operator would be required to include in the initial compliance report a statement

indicating whether each of the equipment specifications has been met.

Selection of Monitoring Requirements

Monitoring requirements are included in standards of performance to provide a means for ensuring proper operation and maintenance of emission reduction systems and to provide plant and enforcement personnel with sufficient data to determine compliance with the proposed standards.

Where thermal incineration is used to achieve compliance, the owner or operator would be required to install, calibrate, operate, and maintain a monitoring device to continuously record the combustion (firebox) temperature of the control device. If catalytic incineration were used, the owner or operator would be required to install a monitoring device to continuously record the gas temperature both upstream and downstream of the catalyst bed. The owner or operator would be required to continually record these values.

Where a control device that recovers VOC is used to achieve compliance with a percent reduction requirement by meeting equipment specifications, the owner or operator would be required to install a continuous monitoring device. Equipment is available to monitor the operational variables associated with solvent recovery system operation. Monitoring of operations indicates whether the solvent recovery system is being properly operated and maintained, and whether the system is continuously reducing VOC emissions to an acceptable level. The variable which would yield the best indication of system operation is VOC concentration at the solvent recovery system outlet.

EPA has not yet developed performance specifications for solvent recovery system monitors, but a program is underway to develop these specifications. Consequently, until EPA proposes and promulgates monitor performance specifications, owners and operators subject to the requirement to install a continuous monitor on the solvent recovery system will not be required to do so.

Recordkeeping and Reporting Requirements

The proposed standards would require that the owner or operator maintain records of all data and calculations used to determine VOC emissions from each affected facility for at least two years. For each affected facility which uses thermal incineration to achieve compliance, continuous records of the incinerator combustion chamber temperature must be maintained at the source for a period of at least two years. Where catalytic incineration is used, continuous records of the gas temperature, both upstream and downstream of the incinerator catalyst bed, must be maintained at the source for a period of at least two years. Where a control device that recovers VOC is used to achieve compliance with a percent reduction requirement by meeting the equipment specifications, the owner or operator must maintain at the source for a period of at least two years continuous records of VOC concentration at the solvent recovery system outlet.

The proposed standards would require the owner or operator to maintain records of all 3-hour periods during which the average temperature of a thermal incinerator is more than 28°C (50°F) less than the average temperature during the most recent performance test at which the destruction efficiency was determined. For catalytic incinerators the owner or operator would maintain records of all 3-hour periods during which the average temperature immediately before the catalyst bed is more than 28°C (50°F) less than the average temperature during the most recent performance test at which the destruction efficiency was determined or the temperature difference across the catalyst bed is less than 80 percent of the average temperature difference during the most recent performance test at which the destruction efficiency was determined. Where a control device that recovers VOC is used to achieve compliance with a percent reduction requirement by meeting the equipment specifications, the owner or operator must maintain records of all 3-hour periods during which the average VOC concentration from the outlet of the solvent recovery system is greater than the average value measured during the most recent test of the control device.

The proposed standards would require notification reports and reports of all initial performance tests, as required by the General Provisions.

Impacts of Reporting Requirements

A reports impact analysis for the rubber tire manufacturing industry was prepared. The purpose of the analysis is to estimate the economic impact of the reporting and recordkeeping requirements that would be imposed by the proposed standards and by those appearing in the General Provisions of 40 CFR Part 60. Included in the analysis are the rationale for the selection of the proposed requirements, an evaluation of the major alternatives considered prior to the selection of the proposed requirements, and a description of the information required by the General Provisions and by the proposed standards. A copy of the reports impact analysis is included in the rubber tire manufacturing docket (EPA Docket No. A-80-9-II-B-14).

Based on the reports impact analysis, a maximum of 3 person-years would be required industry-wide to comply with the recordkeeping and reporting requirements through the first five years of applicability.

The Paperwork Reduction Act of 1980 (Pub. L. 96-511) requires clearance from the Office of Management and Budget (OMB) of certain public reporting/recordkeeping requirements before this rulemaking can be promulgated as final. The reporting/recordkeeping requirements associated with this standard have been submitted to OMB for approval.

Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the **ADDRESSES** section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section address given in the **ADDRESSES** section of this preamble.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (see **ADDRESSES** section of this preamble).

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered in the development of this proposed rulemaking. The principal purposes of the docket are (1) to allow interested parties to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review (except for those portions of the docket excluded from the record under Section 307(d)(7)(A)).

Miscellaneous

As prescribed by Section 111, establishment of standards of performance for rubber tire manufacturing plants was preceded by the Administrator's determination (40

CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the proposed test methods.

It should be noted that standards of performance for new stationary sources established under Section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. (Section 111(a)(1).)

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, Section 173 of the Act requires that a new or modified source constructed in an area where ambient pollutant concentrations exceed the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level that reflects the "lowest achievable emission rate" (LAER), as defined in Section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (Section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources (referred to in Section 169(1)) employ "best available control technology" (BACT) as defined in Section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 111 (or 112) of the Act.

In all events, State Implementation Plans (SIPs) approved or promulgated under Section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIPs must in some cases require greater emission reduction than those required by standards of performance for new sources.

States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the NAAQS under Section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

This regulation will be reviewed four years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in this regulation will be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the Background Information Document.

"Major Rule" Determination. Under Executive Order 12291, EPA is required to judge whether a regulation is a "major rule" and therefore subject to certain requirements of the Order. The Agency has determined that this regulation would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." Fifth-year annualized costs of the standard, compared to an uncontrolled situation, would be about $3.4 million in the worst case. The product wholesale price is not expected to increase. The Agency has therefore concluded that the proposed regulation is not a "major rule" under Executive Order 12291.

This regulation was submitted to the Office of Management and Budget for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are available for public inspection in Docket No. A-80-9, EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Regulatory Flexibility Analysis Certification. The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to current Small Business Administration guidelines, a small business in the SIC category 3011, "Tires and innertubes," is one that has 1,000 employees or less. This is the criterion to qualify for SBA loans or for the purpose of government procurement. Of the 16 tire manufacturing companies, 3 existing companies have less than 1,000 employees. An industry representative has stated that employment in a typical new plant is expected to average 1,400, with a range of 1,000 to 2,000. Thus, it is unlikely that any new plant would be considered a small entity. Existing small entities are not expected to become subject to the NSPS through new construction, modification, or reconstruction. However, if a small business did become subject to the NSPS, the cost of compliance would have minimal impacts.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the attached rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel sulfuric acid plants, Waste treatment and disposal, Zinc, Tires.

Dated: January 5, 1983.

John W. Hernandez, Jr.,

Acting Administrator.

PART 60—[AMENDED]

It is proposed that 40 CFR Part 60 be amended by adding a new Subpart BBB to read as follows:

Subpart BBB—Standards of Performance for the Rubber Tire Manufacturing Industry

Sec.

60.540 Applicability and designation of affected facilities.
60.541 Definitions.
60.542 Standards for volatile organic compounds.
60.543 Performance test and compliance provisions.
60.544 Monitoring of emissions and operations.
60.545 Reporting and recordkeeping requirements.
60.546 Reference methods and procedures.

Authority: Secs. 111 and 301(a), Clean Air Act, as amended, (42 U.S.C. 7411, 7601(a)), unless otherwise noted.

* * * * *

Subpart BBB—Standards of Performance for the Rubber Tire Manufacturing Industry

§ 60.540 Applicability and designation of affected facilities.

(a) The provisions of this subpart apply to the following affected facilities in rubber tire manufacturing plants: each undertread cementing operation, each sidewall cementing operation, each tread end cementing operation, each bead cementing operation, each inside green tire spraying operation, each outside green tire spraying operation, each Michelin-A operation, each Michelin-B operation, and each Michelin-C-automatic operation.

(b) The provisions of this subpart apply to each affected facility which is identified in paragraph (a) of this section and which commences construction or modification after January 20, 1983.

(c) The provisions of § 60.544(c), § 60.545(c)(3), § 60.545(f), and § 60.545(h) will not apply until EPA has established and promulgated performance specifications for the VOC concentration monitoring device. After the promulgation of performance specifications, these provisions will apply to each affected facility under paragraph (b) of this section.

§ 60.541 Definitions.

(a) All terms which are used in this subpart and are not defined below are given the same meaning as in the Act and in Subpart A of this part.

(1) "Bead" means rubber covered strands of wire, wound into a circular form, which ensure a seal between a tire and the rim of the wheel onto which the tire is mounted. Each tire usually contains two beads.

(2) "Bead cementing operation" means the system which is used to apply cement to the bead rubber before or after it is wound into its final circular form. A bead cementing operation consists of a cement application station, such as a dip tank, spray booth and nozzles, cement through and roller or swab applicator; and all other equipment necessary to apply cement to wound beads or bead rubber and to allow evaporation of solvent from cemented beads.

(3) "Component" means a piece of tread, combined tread/sidewall, or separate sidewall rubber of the length needed to manufacture a tire of the size and type for which the component is produced.

(4) "Drying area" means the area where VOC from applied cement or green tire sprays is allowed to evaporate.

(5) "Enclosure" means a structure, designed to contain evaporated VOC, which surrounds a cement, solvent, or spray application area, and/or drying area and ducts contained VOC to a control device(s). Enclosures may have permanent and temporary openings.

(6) "Green tire" means an assembled, uncured tire.

(7) "Inside green tire spraying operation" means the system used to apply a mold release agent and lubricant to the inside of green tires to facilitate the curing process and prevent rubber from sticking to the curing press. Sprays may be organic solvent-based or water-based. An inside green tire spraying operation consists of the inside spray application station and related equipment, such as the lubricant supply system, the booth where spraying is performed, and associated fans and ductwork.

(8) "Michelin-A operation" means that operation where cement is applied which is identified as Michelin-A in the Emission Standards and Engineering Division confidential file as referenced in Docket A-80-9-II-B-12.

(9) "Michelin-B operation" means that operation where cement is applied which is identified as Michelin-B in the Emission Standards and Engineering Division confidential file as referenced in Docket A-80-9-II-B-12.

(10) "Michelin-C-automatic operation" means that operation where cement is automatically applied which is identified as Michelin-C-automatic in the Emission Standards and Engineering Division confidential file as referenced in Docket A-80-9-II-B-12.

(11) "Outside green tire spraying operation" means the system used to apply a mold release agent to the outside of green tires to facilitate the curing process and prevent rubber from sticking to the curing press. Sprays may be organic solvent-based or water-based. An outside green tire spraying operation consists of the outside spray application station and related equipment, such as the lubricant supply system, the booth where spraying is performed, and associated fans and ductwork.

(12) "Permanent opening" means an opening designed into an enclosure to allow tire components to pass through the enclosure by conveyor or other mechanical means, to provide access for permanent mechanical or electrical equipment, or to direct air flow through the enclosure. A permanent opening is not equipped with a door or other means of obstruction.

(13) "Sidewall cementing operation" means the system used to apply cement to a continuous strip of sidewall component. A sidewall cementing operation consists of a cement application station and all other equipment, such as the cement supply system and feed and takeaway conveyors, necessary to apply cement to sidewall strips and to allow evaporation of solvent from cemented sidewall.

(14) "Temporary opening" means an opening into an enclosure that is equipped with a means of obstruction, such as a door, window, or port, which is normally closed.

(15) "Tire" means any agricultural, airplane, industrial, mobile home, light-duty truck and/or passenger vehicle tire which has a bead diameter less than or equal to 0.5 meter (m) [19.7 inches] and cross section dimension less than or equal to 0.325 m (12.8 in.) and is mass produced in an assembly-line fashion.

(16) "Tread end cementing operation" means the system used to apply cement to one or both ends of tread or combined tread/sidewall component. A tread end cementing operation consists of a cement application station and all other equipment, such as the cement supply

system and feed and takeaway conveyors, necessary to apply cement to tread ends and to allow evaporation of solvent from cemented tread ends.

(17) "Undertread cementing operation" means the system used to apply cement to a continuous strip of tread or combined tread/sidewall component. An undertread cementing operation consists of a cement application station and all other equipment, such as the cement supply system and feed and takeaway conveyors, necessary to apply cement to tread or combined tread/sidewall strips and to allow evaporation of solvent from cemented tread or combined tread/sidewall.

(18) "VOC emission control device" means equipment that destroys or recovers VOC.

(19) "VOC emission reduction system" means a system composed of an enclosure, hood, or other device for containment and capture of VOC emissions and a VOC emission control device.

(b) Notations used under this subpart are defined below:

C_a = Concentration of VOC in gas stream in vents after control device (parts per million by volume)

C_b = concentration of VOC in gas stream in vents before control device (parts per million by volume)

C_f = concentration of VOC in gas stream in vents from affected facility to atmosphere (parts per million by volume)

D_c = density of cement or spray material (grams per litre)

D_r = density of VOC recovered by an emission control device (grams per litre)

E = emission control device efficiency, inlet versus outlet (fraction)

F_c = capture efficiency, VOC captured and routed to one control device versus total VOC used for an affected facility (fraction)

F_o = fraction of total mass of VOC used in a calendar month by all facilities served by a common cement or spray material distribution system that is used by a particular affected facility served by the common distribution system

G = monthly average mass of VOC used per complete tire processed for a particular affected facility (grams per tire)

L_c = volume of cement or spray material used for a calendar month (litres)

L_r = volume of VOC recovered by an emission control device (litres)

M = total mass of VOC used for a calendar month by all facilities served by a common cement or spray material distribution system (grams)

M_o = total mass of VOC used at an affected facility for a calendar month (grams)

M_r = mass of VOC recovered by an emission control device (grams)

N = mass of VOC emitted to the atmosphere per complete tire processed for an affected facility for a calendar month (grams per tire)

Q_a = volumetric flow rate in vents after control device (dry standard cubic meters per hour)

Q_b = volumetric flow rate in vents before control device (dry standard cubic meters per hour)

Q_f = volumetric flow rate in vents from affected facility to atmosphere (dry standard cubic meters per hour)

R = overall efficiency of an emission reduction system (fraction)

T_o = total number of tires processed at a particular affected facility for a calendar month

W_o = weight fraction of VOC in a cement or spray material.

§ 60.542 Standards for volatile organic compounds.

(a) On and after the date on which § 60.8(b) requires a performance test to be completed, each owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere more than:

(1) For each undertread cementing operation:

(i) 25 percent of the VOC used (75 percent emission reduction) for each calendar month if the operation uses more than 25 grams of VOC per tire processed; or

(ii) 25 grams of VOC per tire processed for each calendar month if the operation uses 25 grams or less of VOC per tire processed and does not employ a VOC emission reduction system.

(2) For each sidewall cementing operation:

(i) 25 percent of the VOC used (75 percent emission reduction) for each calendar month if the operation uses more than 25 grams of VOC per tire processed; or

(ii) 25 grams of VOC per tire processed for each calendar month if the operation uses 25 grams or less of VOC per tire processed and does not employ a VOC emission reduction system.

(3) For each tread end cementing operation: 10 grams of VOC per tire process for each calendar month.

(4) For each bead cementing operation: 10 grams of VOC per tire processed for each calendar month.

(5) For each inside green tire spraying operation: 1.2 grows per tire processed for each calendar month.

(6) For each outside green tire spraying operation: 9.3 grams per tire processed for each calendar month.

(7) For each Michelin-A operation: 35 percent of the VOC used for each calendar month (65 percent emission reduction).

(8) For each Michelin-B operation: 25 percent of the VOC used for each calendar month (75 percent emission reduction).

(9) For each Michelin-C-automatic operation: 35 percent of the VOC used for each calendar month (65 percent emission reduction).

§60.543 Performance test and compliance provisions.

(a) Section 60.8(d) does not apply to the monthly performance test procedures required by this subpart. Section 60.8(d) does apply to initial performance tests. Section 60.8(f) does not apply when Reference Method 24 is used.

(b) The owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8(a) except as described in paragraph (h) of this section. The owner or operator of an affected facility shall thereafter conduct a performance test each calendar month except as described in paragraphs (e)(1) and (h) of this section. Initial and monthly performance tests shall be conducted according to the procedures in this section.

(c) For each undertread cementing, sidewall cementing, tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying operation which does not use a VOC emission reduction system, the owner or operator shall use the following procedure to determine compliance with the applicable g/tire limit specified under § 60.542(a).

(1) Calculate the total mass of VOC (M_o) used at the affected facility for the calendar month by the following procedure.

(i) For each affected facility for which cement or spray is delivered in batch or via a distribution system which serves only that affected facility:

$$M_o = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi}$$

where: n equals the number of different cements or sprays used during the calendar month.

(ii) For each affected facility for which cement or spray is delivered via a common distribution system which also

serves other affected or existing facilities.

(A) Calculate the total mass (M) of VOC used for all of the facilities served by the common distribution system for the calendar month:

$$M = \sum_{i=1}^{n} L_{oi} D_{ci} W_{oi}$$

where: n equals the number of different cements or sprays used during the calendar month.

(B) Determine the fraction (F_o) of M used by the affected facility by comparing the production records and process specifications for the material cemented or sprayed at the affected facility for the calendar month to the production records and process specifications for the material cemented or sprayed at all other facilities served by the common distribution system for the calendar month or by another procedure acceptable to the Administrator.

(C) Calculate the total monthly mass of VOC(M_o) used by the affected facility:

$$M_o = MF_o$$

(2) Determine the total number of tires (T_o) processed at the affected facility for the calendar month by the following procedure.

(i) For undertread cementing, T_o equals the number of tread or combined tread/sidewall components which receive an application of undertread cement.

(ii) For sidewall cementing, T_o equals the number of sidewall components which receive an application of sidewall cement, divided by 2.

(iii) For tread end cementing, T_o equals the number of tread or combined tread/sidewall components which receive an application of tread end cement.

(iv) For bead cementing, T_o equals the number of beads which receive an application of bead cement, divided by 2.

(v) For inside green tire spraying, T_o equals the number of green tires which receive an application of inside green tire spray.

(vi) For outside green tire spraying, T_o equals the number of green tires which receive an application of outside green tire spray.

(3) Calculate the mass of VOC used per tire processed (G) by the affected facility for the calendar month:

$$G = \frac{M_o}{T_o}$$

(4) Calculate the mass of VOC emitted per tire processed (N) for the affected facility for the calendar month:

$$N = G$$

(5) Where the value of the mass of VOC emitted per tire processed (N) is less than or equal to the applicable g/tire limit specified under § 60.542(a), the affected facility is in compliance.

(d) The owner or operator shall use the following procedure for each tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying operation which uses a VOC emission reduction system with a control device that destroys VOC (e.g., incinerator) to comply with the applicable g/tire limit specified under § 60.542(a).

(1) Calculate the mass of VOC used per tire processed (G) for the affected facility for the calendar month as described under § 60.543(c)(3).

(2) Calculate the mass of VOC emitted per tire processed (N) for the affected facility for the calendar month:

$$N = G(1-R)$$

For the initial performance test, the overall reduction efficiency (R) shall be determined as prescribed in (d)(2) (i), (ii), and (iii) of this section. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency (R) for the performance test providing the control device and capture system operating conditions have not changed. The procedure in (d)(2) (i), (ii), and (iii) of this section shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the most recent determination of overall reduction efficiency.

(i) Determine the fraction (F_c) of total VOC used for the affected facility which enters the control device, the owner or operator of an affected facility shall construct a temporary total enclosure around the application and drying areas during the performance test for the purpose of capturing fugitive VOC emissions and use the following equation:

$$F_c = \frac{\sum_{i=1}^{m} C_{ai} Q_{ai}}{\sum_{i=1}^{m} C_{ai} Q_{ai} + \sum_{i=1}^{n} C_{si} Q_{si}}$$

where: m is the number of vents from the affected facility to the control device and n is the number of vents from the affected facility to the atmosphere.

(ii) Determine the destruction efficiency (E) of the control device by using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the control device by the following equation:

$$E = \frac{\sum_{i=1}^{n} Q_{bi} C_{bi} - \sum_{i=1}^{m} Q_{ai} C_{ai}}{\sum_{i=1}^{n} Q_{bi} C_{bi}}$$

where: n is the number of vents before the control device, and m is the number of vents after the control device.

(iii) Determine the overall reduction efficiency (R) using the following equation:

$$R = EF_c$$

(3) Where the value of the mass of VOC emitted per tire processed (N) is less than or equal to the applicable g/tire limit specified under § 60.524(a), the affected facility is in compliance.

(e) The owner or operator shall use the following procedure for each undertread cementing, sidewall cementing, Michelin-A, Michelin-B, and Michelin-C-automatic affected facility which uses a VOC emission reduction system with a control device that destroys VOC (e.g., incinerator) to comply with the applicable percent emission reduction requirement specified under § 60.542(a).

(1) For the initial performance test, the overall reduction efficiency (R) shall be determined as prescribed in § 60.543(d)92)(i)—(iii). The performance test shall be repeated using this same procedure when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the most recent determination of overall reduction efficiency. No monthly performance tests are required.

(2) Each undertread cementing, sidewall cementing, or Michelin-B facility where R is greater than or equal to 0.75 is in compliance.

(3) Each Michelin-A or Michelin-C-automatic facility where R is greater than or equal to 0.65 is in compliance.

(f) The owner or operator shall use the following procedure for each tread end cementing, bead cementing, inside green tire spraying, and outside green tire spraying affected facility which uses a

VOC emission reduction system with a control device that recovers VOC (e.g., carbon adsorber) to comply with the applicable g/tire limits specified under § 60.542(a).

(1) Calculate the mass of VOC used per tire processed (G) at the affected facility for the calendar month as described under § 60.543(c)(3).

(2) Calculate the total mass of VOC recovered (M_r) from the affected facility for the calendar month using the following equation:

$$M_r = L_r D_r$$

(3) Calculate the overall reduction efficiency (R) for the VOC emission reduction system for the calendar month using the following equation:

$$R = \frac{M_r}{M_o}$$

(4) Calculate the mass of VOC emitted per tire processed (N) for the affected facility for the calendar month using the following equation:

$$N = G(1-R)$$

(5) Where the value of the mass of VOC emitted per tire processed (N) is less than or equal to the applicable g/tire limit specified under § 60.542(a), the affected facility is in compliance.

(g) The owner or operator shall use the following procedure for each undertread cementing, sidewall cementing, Michelin-A, Michelin-B, and Michelin-C-automatic affected facility which uses a VOC emission reduction system with a control device that recovers VOC (e.g., carbon adsorber) to comply with the applicable percent reduction requirement specified under § 60.542(a).

(1) Calculate the total mass of VOC used at the affected facility (M_o) for the calendar month as described under § 60.543(c)(1).

(2) Calculate the total mass of VOC recovered (M_r from the affected facility for the calendar month using the following equation:

$$M_r = L_r D_r$$

(3) Calculate the overall reduction efficiency (R) for the VOC emission reduction system for the calendar month using the following equation:

$$R = \frac{M_r}{M_o}$$

(4) Each undertread cementing, sidewall cementing, or Michelin-B facility where R is greater than or equal to 0.75 is in compliance.

(5) Each Michelin-A or Michelin-C-automatic facility where R is greater than or equal to 0.64 is in compliance.

(h) Rather than demonstrate compliance with the provisions of § 60.542(a)(1),(2), or (8) using the performance test procedures described in paragraphs (e) and (g) of this section, an owner or operator of an undertread cementing, sidewall cementing, or Michelin-B affected facility that uses a VOC emission reduction system may demonstrate compliance by meeting the equipment design and performance specifications listed in (1)–(5) below and by conducting a performance test to demonstrate compliance with (5) below. The owner or operator shall conduct this performance test of the control device efficiency (as specified in § 60.8(a)) not later than 180 days after initial startup of the affected facility. The Administrator has decided that meeting the capture system design and performance specifications, in conjunction with operating a 95 percent efficient control device, is an acceptable means of demonstrating compliance with the standard. Therefore, in accordance with § 60.8(b), the Administrator has waived the requirement for a performance test on the enclosure (as required by § 0.8(a)). No monthly performance tests are required.

(1) The cement application and drying area of the affected facility shall be contained in an enclosure which meets the criteria in paragraphs (h) (2), (3), and (4) of this section;

(2) The drying area shall be enclosed between the application area and the water bath or to the extent necessary to contain all tire components for at least 30 seconds after cement application, whichever distance is less;

(3) A minimum face velocity of 100 feet per minute shall be maintained through each permanent opening into an enclosure;

(4) The total area of all permanent openings into the enclosure shall not exceed the area that would be necessary to maintain the VOC concentration of the exhaust gas stream at 25 percent of the lower explosive limit (LEL) under the following conditions:

(i) The affected facility is operating at maximum solvent use rate;

(ii) The face velocity through each permanent opening is 100 feet per minute;

(iii) All temporary openings are closed.

(5) All captured VOC are ducted to a VOC emission control device which achieves at least 95 percent destruction or recovery efficiency. To determine the efficiency (E) of the control device, for the initial performance test, use values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the control device by the following equation:

$$E = \frac{\sum_{i=1}^{n} Q_{bi} C_{bi} - \sum_{j=1}^{m} Q_{aj} C_{aj}}{\sum_{i=1}^{n} Q_{bi} C_{bi}}$$

The control device efficiency shall be redetermined when directed by the Administrator or when the owner or operator elects to operate the control device at conditions different from the most recent determination of control device efficiency.

§ 60.544 Monitoring of emissions and operations.

(a) Each owner or operator subject to the provisions of this subpart and using a VOC emission reduction system with a thermal incinerator shall continuously monitor and record the temperature of the gas in the combustion zone. The monitoring instrument shall have an accuracy equal to ±0.75 percent of the temperature being measured in °C or ±2.5°C, whichever is greater.

(b) Each owner or operator subject to the provisions of this subpart and using a VOC emission reduction system with a catalytic incinerator shall continuously monitor and record the temperature in the gas stream immediately before and after the catalyst bed. The monitoring instruments shall have an accuracy equal to ±0.75 percent of the temperature being measured in °C or ±2.5°C, whichever is greater.

(c) Each owner or operator of an undertread cementing, sidewall cementing, or Michelin-B operation which uses a VOC emission control device that recovers VOC to meet the requirements of § 60.543(h)(5) shall continuously monitor and record the VOC concentration of the exhaust gas stream from the VOC recovery device. The VOC concentration monitoring device shall be installed in a location that is representative of the VOC concentration in the exhaust vent, at least two equivalent stack diameters from the exhaust point, and protected from any interferences due to wind, weather, or other processes.

(d) Each monitoring device shall be installed, calibrated, operated, and maintained according to accepted practices and the manufacturer's specifications.

§ 60.545 Reporting and recordkeeping requirements.

(a) Each owner or operator of an affected facility shall include the following data in the initial performance test report required under § 60.8(a).

(1) For each affected facility which complies with a g/tire limit specified in § 60.542(a) without the use of a VOC emission reduction system.

(i) The mass of VOC used (M_o), the number of tires processed (T_o), and the mass of VOC emitted per tire processed (N).

(ii) A description of the method used to determine M_o and T_o.

(2) For each affected facility which uses a VOC emission reduction system with a control device that destroys VOC (e.g., incinerator) to comply with a g/tire limit specified in § 60.542(a).

(i) The mass of VOC used (M_o), the number of tires processed (T_o), the mass of VOC emitted per tire processed (N), the mass of VOC used per tire processed (G), the emission control device efficiency (E), the capture system efficiency (F_c), the overall system emission reduction (R), and the mass of VOC emitted per tire processed (N).

(ii) A description of the method used to determine M_o, T_o, E, and F_c.

(3) For each affected facility which uses a VOC emission reduction system with a control device that destroys VOC (e.g., incinerator) to comply with a percent emission reduction requirement specified in § 60.542(a).

(i) The emission control device efficiency (E), the capture system efficiency (F_c), and the overall system emission reduction (R).

(ii) A description of the method used to determine E and F_c.

(4) For each affected facility which uses a VOC emission reduction system with a control device that recovers VOC (e.g., carbon adsorber) to comply with a g/tire limit specified in § 60.542(a).

(i) The mass of VOC used (M_o), the number of tires processed (T_o), the mass of VOC used per tire processed (G), the mass of VOC recovered (M_r), the overall system emission reduction (R), and the mass of VOC emitted per tire processed (N).

(ii) A description of the method used to determine M_o and T_o.

(5) For each affected facility which uses a VOC emission reduction system with a control device that recovers VOC (e.g., carbon adsorber) to comply with a percent emission reduction requirement specified in § 60.542(a).

(i) The mass of VOC used (M_o), the mass of VOC recovered (M_r), and the overall system emission reduction (R).

(ii) A description of the method used to determine M_o.

(b) Each owner or operator of an undertread cementing, sidewall cementing, or Michel in-B affected facility where the method in § 60.543(h) has been chosen to demonstrate compliance shall include in the initial compliance report a statement indicating which of the equipment design and performance specifications have been met and identifying each which has not been met. The initial compliance report shall also include the following data.

(1) The emission control device efficiency (E), the airflow through all permanent enclosure openings with all temporary enclosure openings unobstructed, the total area of all permanent enclosure openings, the total area of all temporary enclosure openings, the maximum solvent use rate (kg/hr), the type(s) of VOC used, the lower explosive limit (LEL) for each VOC used, and the length of time each component is enclosed after application of cement or spray material.

(2) A description of the method used to determine E, the system airflow, and the maximum solvent use rate.

(c) Each owner or operator of an affected facility shall include the following data, as measured by the continuous monitoring device(s), in the initial performance test report.

(1) The average combustion temperature during the test of incinerator destruction efficiency for each thermal incinerator.

(2) The average temperature before and after the catalyst during the test of incinerator efficiency for each catalytic incinerator.

(3) The average VOC concentration of the exhaust gas stream from the VOC recovery device during the test of VOC recovery device efficiency for each undertread cementing, sidewall cementing, or Michel in-B operation that uses a VOC emission control device that recovers VOC to meet the requirements of §60.543(h)(5).

(d) Each owner or operator of an affected facility which uses a thermal incinerator shall maintain at the source, for a period of at least two years, records of all 3-hour periods of operation for which the average combustion temperature was more than 28°C (50°F) below the temperature at which the destruction efficiency of the thermal incinerator was last determined.

(e) Each owner or operator of an affected facility which uses a catalytic incinerator shall maintain at the source, for a period of at least two years, records of all 3-hour periods of operation for which the average temperature before the catalyst bed is more than 28°C below the temperature at which the destruction efficiency of the catalytic incinerator was last determined, and all 3-hour periods for which the average temperature difference across the catalyst bed is less than 80 percent of the temperature difference when the destruction efficiency of the catalytic incinerator was last determined.

(f) Each owner or operator of an undertread cementing, sidewall cementing, or Michelin-B operation which uses a VOC emission control device that recovers VOC to meet the requirements of § 60.543(h)(5) shall maintain at the source, for a period of at least two years, records of all 3-hour periods of operation for which the average VOC concentration of the exhaust gas stream from the VOC recovery device exceeds the average value measured during the most recent test of the control device.

(g) Each owner or operator subject to the provisions of this subpart shall maintain at the source, for a period of at least two years, records of all data and calculations used to determine VOC emissions from each affected facility. At affected facilities where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain at the source, for a period of at least two years, continuous records of the incinerator combustion chamber temperature. If catalytic incineration is used, the owner or operator shall maintain at the source, for a period of at least two years, continuous records of the gas temperature, both upstream and downstream of the incinerator catalyst bed.

(h) Each owner or operator of an undertread cementing, sidewall cementing, or Michelin-B operation that uses a VOC emission control device that recovers VOC to meet the requirements of § 60.543(h)(5) shall maintain at the source, for a period of at least two years, continuous records of the VOC concentration of the exhaust gas stream from the VOC recovery device.

(i) Each owner or operator is exempted from the quarterly reports required under § 60.7(c).

§ 60.546 Reference methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8, shall be used to conduct performance tests.

(1) Reference Method 24 for the determination of the VOC content of cements or green tire spray materials. In the event of dispute, Reference Method 24 shall be the reference method.

(2) Reference Method 25 for the determination of the VOC concentration in the effluent gas in each stack entering and leaving an emission control device. The owner or operator shall notify the Administrator 30 days in advance of any stack test by Reference Method 25. The following reference methods are to be used in conjunction with Reference Method 25:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 for velocity and volumetric flow rate,

(iii) Method 3 for gas analysis, and

(iv) Method 4 for stack gas moisture.

(b) For Reference Method 24, the cement or green tire spray sample must be a 1-litre sample collected in a 1-litre container at a point where the sample will be representative of the material as applied in the affected facility.

(c) For Reference Method 25, the sampling time for each of three runs must be at least one hour. The minimum sample volume must be 0.003 dscm except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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February 4, 1983

Part III

Environmental Protection Agency

Waivers From New Source Performance Standards; Innovative Technology Waivers for Five Automobile and Light-Duty Truck Surface Coating Operations; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2242-4]

Waivers From New Source Performance Standards; Innovative Technology Waivers for Five Automobile and Light-Duty Truck Surface Coating Operations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of final rulemaking.

SUMMARY: On August 6, 1982 (47 FR 34342), the Environmental Protection Agency proposed to grant innovative technology waivers, pursuant to Section 111(j) of the Clean Air Act, as amended (the Act), 42 U.S.C. 7411(j), for topcoat operations at five automobile and light-duty truck assembly plants. This action grants those waivers. These waivers provide an opportunity to demonstrate the capability of base coat/clear coat (BC/CC) topcoat coating systems to achieve greater VOC (volatile organic chemicals) emission reductions than required by the existing standards at lower costs.

EFFECTIVE DATE: February 4, 1983.

Under Section 307(b)(1) of the Clean Air Act, judicial review of these waivers is available *only* by the filing of petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication. The issuance of these waivers is based on determinations of nationwide scope and effect. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: Under Section 307(d)(2), 42 U.S.C. 7607(d)(2), the Administrator is required to establish two separate rulemaking dockets for each rule that would apply only within the boundaries of one State. One copy of each docket is located in Washington, D.C. at EPA's Central Docket Section, West Tower Lobby, Gallery 1, 401 M Street, S.W. A second copy of each docket is located at the EPA Regional Office for the State where the plant is located. The Regional Office locations are listed below:

- For GM's Wentzville, Missouri plant: Environmental Protection Agency, Region VII, Mr. Charles Whitmore, Docket number (See Table 1), 342 East 11th Street, Kansas City, Missouri
- For GM's Detroit, Michigan, plant, GM's Orion Township, Michigan plant, and/or Honda's Marysville, Ohio plant: Environmental Protection Agency, Region V, Mr. Gary Gulezman, Docket Numbers (See Table 1), 230 South Dearborn Street, Chicago, Illinois
- For Nissan's Smyrna, Tennessee, plant: Environmental Protection Agency, Region IV, Mr. Brian Beals, Docket Number (See Table 1), 345 Courtland Street, N.E., Atlanta, Georgia

TABLE 1.—DOCKET NUMBERS

Plant location	Docket No.
1. GM—Wentzville, Missouri	A-82-11
2. GM—Detroit, Michigan	A-82-12
3. GM—Orion Township, Michigan	A-82-13
4. Honda—Marysville, Ohio	A-82-15
5. Nissan—Smyrna, Tennessee	A-82-16

The dockets may be inspected at the listed addresses between 8 a.m. and 4 p.m. on weekdays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

SUPPLEMENTARY INFORMATION:

Background

Current Regulations

On October 5, 1979, pursuant to Section 111 of the Clean Air Act, standards of performance were proposed to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed automobile and light-duty truck surface coating operations (44 FR 57792). Final standards were published in the Federal Register on December 24, 1980 (45 FR 85410).

Standards of performance under Section 111 are established at levels that reflect best demonstrated technology (BDT). For automobile and light-duty truck topcoat operations, BDT was determined to be the use of low-VOC content waterborne coatings applied with the best demonstrated air atomized spray techniques. The standard of 1.47 kg VOC per liter of applied coating solids for topcoat operations was based on the use of this coating system at three U.S. plants. The standard does not, however, require use of waterborne coatings. Any coating system capable of reducing VOC emissions to 1.47 kg VOC per liter of applied coating solids may be used. Other methods which could be used independently or in various combinations to achieve the topcoat standard are low-VOC content solvent-borne coatings, add-on control devices such as incinerators and carbon adsorbers, and high efficiency coating application techniques.

Trends in Automobile Topcoats

Since the standard was proposed in 1979, the trend in the domestic automobile industry has been to develop and use low-VOC content solvent-borne topcoats with improved transfer efficiency, rather than more costly waterborne coatings, to reduce VOC emissions and improve finish quality. Low-VOC content topcoats are available for production line use. These coatings have been demonstrated to be of acceptable quality and appearance and, when used in combination with better transfer efficiency and/or bake oven emission control systems (i.e., energy efficient incinerators), will meet the standard.

Recently, however, a new type of topcoat called base coat/clear coat (BC/CC) has been developed for automobiles and light-duty trucks. BC/CC topcoats consist of a relatively thin layer of highly pigmented base coat followed by a thicker layer of clear coat. BC/CC coatings have a more appealing appearance than single coat topcoats and also offer improved chemical resistance and gloss retention. Vehicles coated with BC/CC topcoats are now being imported to the United States in significant quantities by both European and Japanese manufacturers. Because of the general appeal and acceptance by U.S. consumers of vehicles coated with BC/CC topcoats, U.S. automobile and light-duty truck manufacturers must duplicate the performance of this type of topcoat to be competitive.

The BC/CC coatings that are being used in foreign plants contain relatively large quantities of VOC. If U.S. manufacturers used similar coatings, the only possible method of meeting the existing standards of performance for automobile and light-duty truck surface coating operations would be to use an entirely new generation of very expensive add-on controls to minimize emissions. BC/CC topcoats with VOC content low enough to comply without such add-on controls are not yet commercially available. The coatings manufacturing companies are working with automobile manufacturers to develop lower VOC content BC/CC topcoats. The automobile manufacturers and equipment vendors are developing efficient spray coating methods for these coatings. The results of this intensive industry development program will ultimately permit the automobile

companies to meet the topcoat standard and still apply BC/CC coatings to automobiles in sufficient number to meet market demand without having to use expensive add-on controls.

Waiver Requests

General Motors Corporation (GM) submitted a request on October 30, 1981, for innovative technology waivers under Section 111(j) of the Clean Air Act for the topcoat operations at three automobile plants now under construction. GM planned to initiate production in 1983 and 1984 at these plants. GM claimed that they needed to use BC/CC topcoats on all of the cars produced at these plants so that they could compete with imported cars. The application of oven controls, use of the lowest VOC content BC/CC coating, and the use of the best control application system available to GM would have resulted in BC/CC topcoat VOC emissions of 3.2 kg VOC per liter of applied coating solids at each of these plants.

Honda submitted a request on November 19, 1981, for an innovative technology waiver under Section 111(j) of the Clean Air Act for the topcoat operation at an automobile plant that is being built in Marysville, Ohio. The plant was scheduled to begin production by the end of 1982. Honda would like to coat most of their cars with BC/CC coatings so that they can match the quality of their cars produced in Japan and exported to the U.S. The use of the lowest VOC content BC/CC coating and the best coating application system available to Honda would have resulted in BC/CC topcoat emissions of 3.1 kg of VOC per liter of applied coating solids.

Nissan Motor Manufacturing Company (Nissan) submitted a request on March 12, 1982, for an innovative technology waiver under Section 111(j) of the Clean Air Act for the topcoat operation at a light-duty truck plant that is being constructed in Smyrna, Tennessee. The plant was scheduled to begin production in August 1983. Nissan would like to coat their light-duty trucks with BC/CC topcoat coatings so that they can match the quality of their light-duty trucks produced in Japan and exported to the U.S. The use of the lowest VOC content BC/CC coating, the application of oven VOC controls, and the use of the best coating application system available to Nissan would have resulted in BC/CC topcoat VOC emissions of 2.3 kg of VOC per liter of applied coating solids.

Requirements of Section 111(j)

Section 111(j) of the Clean Air Act sets forth provisions for the issuance of waivers for the development of innovative technology. In the 1977 Amendments to the Clean Air Act, Congress added this provision to encourage the use of innovative "technological systems of continuous emission reduction" for the control of air pollutants. Their intent in doing so was to provide a statutory incentive for the improvement of emission control technology and for reducing costs, environmental impacts, and energy usage of such technology.

Under Section 111(j) of the Act, upon request by the owner or operator of a new source and with the consent of the Governor of the State in which the source is located, the Administrator is authorized to grant a waiver from the requirements of Section 111 for a limited time period provided certain statutory prerequisites are satisfied. The Administrator must determine that:

a. The proposed innovative system has not been adequately demonstrated;

b. The proposed innovative system will operate effectively and there is substantial likelihood that the system will achieve greater continuous emission reduction than otherwise required or achieve an equivalent emission reduction at lower cost in terms of energy, economic, or nonair quality environmental impact;

c. The owner or operator of the proposed system has demonstrated to the Administrator's satisfaction that the system will not cause or contribute an unreasonable risk to public health, welfare, or safety; and

d. The proposed waiver for the specific innovative technological system is not in excess of the number of waivers necessary to ascertain whether or not such system will achieve the conditions set forth in "b" and "c" immediately above.

Additionally, Section 111(j)(1)(B) of the Act requires an innovative technology waiver to be granted on such terms and conditions during the waiver period as the Administrator determines necessary:

a. To ensure emissions from the source will not prevent attainment and maintenance of any national ambient air quality standards, and

b. To ensure proper functioning of the innovative technological system.

Proposed Waivers

The Agency reviewed the waiver requests with regard to the requirements under Section 111(j) of the Act and concluded that these requests met the requirements of the Act. Therefore, the Administrator proposed on August 6, 1982, to grant innovative technology waivers to five automobile and light-duty truck plants subject to the concurrence of the Governors of the States where the plants are located.

Public Participation

The waivers were proposed and published in the Federal Register on August 6, 1982 (47 FR 34342). The preamble to the proposed waivers discussed in detail information relating to BC/CC systems and the requirements of waivers under Section 111(j) of the Clean Air Act. Public comments were solicited at the time of proposal and interested persons were given the opportunity to request a public hearing on each of the waivers. No public hearings were requested.

Comment letters were received from the automobile industry, State air pollution control agencies, State Governors, and a regional commerce association. The comments in these letters have been carefully considered and where determined to be appropriate by the Administrator, changes have been made to the proposed waivers. This preamble contains a summary of these comments and the Agency's responses which serves as a basis for the revision made to the waivers between proposal and promulgation.

Significant Comments

General

One commenter, Ford Motor Company, argued that the standards should be revised by treating topcoat operations using BC/CC as a separate class of sources subject to a more lenient (or no) emission limit. This comment, in effect, really concerns the validity of the standards rather than the appropriateness of the waivers. The topcoat standards of performance reflect the best demonstrated technology for topcoat operations as required by Section 111(a)(1) of the Act. The standards need not be revised merely because source owners are developing alternative compliance techniques, some of which, like BC/CC, promise to lower the cost of compliance and improve product quality.

Two commenters, GM and Honda, requested that the waivers be extended to allow the use of all BC/CC topcoats and not just metallic BC/CC topcoats. The commenters pointed out that since the initial waiver requests were submitted, the need for developing non-metallic BC/CC topcoat coatings to meet foreign competition has emerged. When these coatings are developed they will be able to meet the existing topcoat standard of performance at a lower cost and result in a coating that has

improved chemical resistance and gloss retention. The commenters pointed out that the advantages of the development of BC/CC topcoats and the level of VOC emissions are identical for both the nonmetallic and the metallic BC/CC topcoat coatings. The Agency has evaluated this comment and found that BC/CC for nonmetallic coatings meets all of the requirements of Section 111(j) of the Act. Therefore, the waivers have been revised to apply to all BC/CC topcoat coatings.

One commenter pointed out that the clear coat portion of the BC/CC coating may be purposely tinted in some cases and may not be completely clear. The commenter wanted this type of clear coat to also be covered by the waiver provisions. The Agency has reviewed this comment and finds that the innovative features of the technology will not change as a result of the tinting of the clear coat and agrees that tinted clear coats are covered by the waiver provisions. No definition was added nor were changes made to the waivers as a result of this comment.

GM Waivers

In their initial waiver request, GM had planned to start-up their three plants using a topcoat system composed of a 20 volume percent solids base coat and a 42 volume percent solids clear coat (i.e., a 20/42 BC/CC coating). GM submitted a comment during the comment period which stated that they could be able to start-up with a 32/44 BC/CC coating which had been in development testing but which they now feel will be available by the second quarter of 1983, the date that the first plant will be started up. The waivers for these three GM plants, therefore, have been revised to limit VOC emissions from BC/CC topcoat coatings to 1.9 kg VOC/liter of applied coating solids rather than the proposed emission limit of 3.2 kg VOC/liter of applied coating solids. This change will reduce the annual increase in VOC emissions as a result of the waivers from each GM plant by approximately 850 tons per year.

Summary of the Final Waivers

General Motors

Three identical waivers are granted to GM for automobile assembly plants being built in Detroit, Michigan, Orion Township, Michigan, and Wentzville, Missouri. The Orion Township and Wentzville plants are scheduled to start production in mid 1983 with the start-up of the Detroit plant planned in mid 1984. The waivers allow VOC emissions from the portion of the topcoat operations which use BC/CC coatings of 1.9 kg of VOC per liter of applied coating solids. The waivers are effective from plant start-up to December 31, 1986.

Honda

A waiver is granted to Honda for an automobile assembly plant being built in Marysville, Ohio. That plant is scheduled to start production in late 1982. The waiver allows VOC emissions from the portion of the topcoat operations which use BC/CC coatings of 3.1 kg VOC/liter of applied coating solids. The waiver is effective from plant start-up to December 31, 1986.

Nissan

A waiver is granted to Nissan for a light-duty truck assembly plant being built in Smyrna, Tennessee. That plant is now scheduled to begin production in late 1982. The waiver allows VOC emissions from the portion of the topcoat operations which uses BC/CC coatings of 2.3 kg VOC/liter of applied coating solids. The waiver is effective from plant start-up to December 31, 1986.

Governors' Concurrences

Honorable James A. Rhodes, Governor of the State of Ohio, Honorable Lamar Alexander, Governor of the State of Tennessee, Honorable Kit Bond, Governor of the State of Missouri, and Honorable William Milliken, Governor of the State of Michigan, have concurred in the innovative technology waivers as set forth herein under Section 111(j)(1)(A) of the Act, 42 U.S.C. 7411(j)(1)(A). Such concurrences are a prerequisite for the granting of innovative technology waivers by the Administrator under Section 111(j) of the Act. The waivers as set forth herein are hereby granted.

Miscellaneous

In accordance with Section 117 of the Act, publication of these final waivers was preceded by consultation with Federal departments and agencies.

The Paperwork Reduction Act of 1980 (PL 96-511) requires EPA to submit to the Office of Management and Budget (OMB) certain public reporting/recordkeeping requirements before proposal. This rulemaking does not involve a "collection of information" as defined in the Paperwork Reduction Act. Therefore, the provisions of the Paperwork Reduction Act applicable to collection of information do not apply to this rulemaking.

The Administrator certifies that a regulatory flexibility analysis under 5 U.S.C. 601 et seq. is not required for this rulemaking because the rulemaking would not have a significant impact on a substantial number of small entities. The rulemaking would not impose any new requirements and therefore no additional costs would be imposed. It is, therefore, classified as nonmajor under Executive Order 12291.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment, Disposal and Zinc.

Dated: January 28, 1983.

Anne M. Gorsuch,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Title 40 Part 60, Subpart MM of the Code of Federal Regulations is amended by adding a new § 60.398 as set forth below:

§ 60.398 Innovative technology waivers

(a) *General Motors Corporation, Wentzville, Missouri, automobile assembly plant.* (1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation automobile assembly plant located in Wentzville, Missouri, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Wentzville assembly plant.

(ii) Commencing on February 4, 1983, and continuing to December 31, 1986, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980) is demonstrated to the Administrator's satisfaction the General Motors Corporation shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Wentzville, Missouri, assembly plant, to either:

(A) 1.9 kilograms of VOC per liter of applied coating solids from base coat/clear coat topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solids from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in

paragraph (a)(1)(ii) of this section, and continuing thereafter, emissions of VOC from each topcoat operations shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(a)(1) (ii)(A).

(v) A technology development report shall be sent to EPA Region VII, 324 East 11th Street, Kansas City, Missouri 64106, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a Federally promulgated standard of performance. As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412 (b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(b) *General Motors Corporation, Detroit, Michigan, Automobile Assembly plant.* (1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation's automobile assembly plant located in Detroit, Michigan, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Detroit assembly plant.

(ii) Commencing on February 4, 1983, and continuing to December 31, 1986, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, the General Motors Corporation shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Detroit, Michigan, assembly plant, to either:

(A) 1.9 kilograms of VOC per liter of applied coating solids from base coat/clear coat topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solids from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in (ii) above, and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(b)(1)(ii)(A).

(v) A technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a Federally promulgated standard of performance. As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412(b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(c) *General Motors Corporation, Orion Township, Michigan, automobile assembly plant.* (1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at General Motors Corporation automobile assembly plant located in Orion Township, Michigan, shall comply with the following conditions:

(i) The General Motors Corporation shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Orion Township assembly plant.

(ii) Commencing on February 4, 1983, and continuing to December 31, 1986, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980) is demonstrated to the Administrator's satisfaction, the General Motors Corporation shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Orion Township, Michigan, assembly plant, to either:

(A) 1.9 kilograms of VOC per liter of applied coating solids from base coat/clear coat topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solids from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in paragraph (c)(1)(ii) of this section and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(c)(1) (ii)(A).

(v) A technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a Federally promulgated standard of performance. As such, it shall be unlawful for General Motors Corporation to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject the General Motors Corporation to enforcement under Section 113 (b) and (c), 42 U.S.C. 7412 (b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(d) *Honda of America Manufacturing, Incorporated (Honda), Marysville, Ohio, automobile assembly plant.* (1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at

Honda's automobile assembly plant located in Marysville, Ohio, shall comply with the following conditions:

(i) Honda shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Marysville assembly plant.

(ii) Commencing on February 4, 1983, and continuing for 4 years or to December 31, 1986, whichever is sooner, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980) is demonstrated to the Administrator's satisfaction, Honda shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at Marysville, Ohio, assembly plant, to either:

(A) 3.1 kilograms of VOC per liter of applied coating solids from base coat/clear coat topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solids from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in paragraph (d)(1)(ii) of this section and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

(iv) Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(d)(1)(ii)(A).

(v) A technology development report shall be sent to EPA Region V, 230 South Dearborn Street, Chicago, Illinois 60604, postmarked before 60 days after the promulgation of this waiver and annually thereafter while this waiver is in effect. The technology development report shall summarize the base coat/clear coat development work including the results of exposure and endurance tests of the various coatings being evaluated. The report shall include an updated schedule of attainment of 40 CFR 60.392(c) (December 24, 1980) based on the most current information.

(2) This waiver shall be a Federally promulgated standard of performance. As such, it shall be unlawful for Honda to operate a topcoat operation in violation of the requirements established in this waiver. Violation of the terms and conditions of this waiver shall subject Honda to enforcement under Section 113(b) and (c), 42 U.S.C. 7412(b) and (c), and Section 120, 42 U.S.C. 7420, of the Act as well as possible citizen enforcement under Section 304 of the Act, 42 U.S.C. 7604.

(e) *Nissan Motor Manufacturing Corporation, U.S.A. (Nissan), Smyrna, Tennessee, light-duty truck assembly plant.* (1) Pursuant to Section 111(j) of the Clean Air Act, 42 U.S.C. 7411(j), each topcoat operation at Nissan's light-duty truck assembly plant located in Smyrna, Tennessee, shall comply with the following conditions:

(i) Nissan shall obtain the necessary permits as required by Section 173 of the Clean Air Act, as amended August 1977, to operate the Smyrna assembly plant.

(ii) Commencing on February 4, 1983, and continuing for 4 years or to December 31, 1986, whichever is sooner, or until the base coat/clear coat topcoat system that can achieve the standard specified in 40 CFR 60.392(c) (December 24, 1980), is demonstrated to the Administrator's satisfaction, Nissan shall limit the discharge of VOC emissions to the atmosphere from each topcoat operation at the Smyrna, Tennessee, assembly plant, to either:

(A) 2.3 kilograms of VOC per liter of applied coating solids from base coat/clear coat topcoats, and 1.47 kilograms of VOC per liter of applied coating solids from all other topcoat coatings; or

(B) 1.47 kilograms of VOC per liter of applied coating solids from all topcoat coatings.

(iii) Commencing on the day after the expiration of the period described in paragraph (e)(1)(ii) of this section and continuing thereafter, emissions of VOC from each topcoat operation shall not exceed 1.47 kilograms of VOC per liter of applied coating solids as specified in 40 CFR 60.392(c) (December 24, 1980).

Each topcoat operation shall comply with the provisions of § 60.393, § 60.394, § 60.395, § 60.396, and § 60.397. Separate calculations shall be made for base coat/clear coat coatings and all other topcoat coatings when necessary to demonstrate compliance with the emission limits in § 60.398(e)(1)(ii)(A).

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Thursday
August 18, 1983

Part II

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Bulk Gasoline Terminals

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-224-6]

Standards of Performance for New Stationary Sources; Bulk Gasoline Terminals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for bulk gasoline terminals were proposed in the **Federal Register** on December 17, 1980 (45 FR 83126). This action promulgates standards of performance for bulk gasoline terminals. These standards implement Section 111 of the Clear Air Act and are based on the Administrator's determination that petroleum transportation and marketing cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed facilities at bulk gasoline terminals to control emissions to the level achievable through use of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: August 18, 1983.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES:

Background Information Document. The background information document (BID, Volume II) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Bulk Gasoline Terminals—Background Information for Promulgated Standard," EPA-450/3-80-038b. BID, Volume II, contains (1) a summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final environmental impact statement which summarizes the impacts of the standards.

Docket. Docket No. A-79-52, containing information considered by EPA in developing the promulgated standards, in available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: For information concerning the background information supporting the promulgated standards contact Mr. James F. Durham, Chemicals, and Petroleum Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5671. For futher information concerning the promulgated standards contact Mr. Gilbert H. Wood, Standards Development Branch, Emissions Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Telephone number (919) 541-5578.

SUPPLEMENTARY INFORMATION:

Summary of Promulgated Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> • • • application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standards of performance limit volatile organic compound (VOC) emissions from each affected facility on which construction, modification, or reconstruction commenced after December 17, 1980 (after August 18, 1983, for reconstructions necessitated by State or local regulations). The affected facility is the total of all the loading racks at a bulk gasoline terminal which deliver either gasoline into any delivery tank truck or some other liquid product into trucks which have loaded gasoline on the immediately previous load.

The promulgated standards require the installation of vapor collection equipment at the terminal to collect total organic compounds vapors displaced from gasoline tank trucks during product loading. The standards limit emissions from the collection system to 35 milligrams of total organic compounds per liter of gasoline loaded, unless the facility has an existing vapor processing system (construction or refurbishment commenced before December 17, 1980). In this latter case, the standards limit emissions from the vapor collection system to 80 mg/liter.

The Agency has concluded that it is quite costly in light of the resulting emission reduction for an owner whose existing facility becomes subject to NSPS (e.g., through modification or reconstruction) to meet 35 mg/liter when the facility already has a system capable of meeting 80 mg/liter.

To control tank truck leakage emissions during loading, the promulgated standards require that loadings be made only into gasoline tank trucks tested for vapor tightness. The terminal owner or operator is required to obtain the identification number and test documentation for each gasoline tank truck loading at the facility. In accordance with Section 111(h)(3) of the Clean Air Act, the Administrator may approve alternative procedures that assure that loading will be limited to vapor-tight trucks.

These standards are based on the use of carbon adsorption and thermal oxidation type vapor processors for the 35 mg/liter limit, which represent the best demonstrated technology. Test data show the ability of these systems of continuous emission reduction to achieve the 35 mg/liter emission limit of the standards of performance. Although only some of the refrigeration systems tested met 35 mg/liter (all the systems tested were designed to meet the State implementation plan (SIP) limit of 80 mg/liter), test data and engineering calculations also support the ability of refrigeration systems to achieve the 35 mg/liter emission limit of the standards. In addition, the major manufacturer has stated that all currently manufactured refrigeration systems can be specified to operate at 35 mg/liter. In selecting these standards, the Agency considered costs, nonair quality health and environmental impacts, and energy requirements.

The proposed section on continuous monitoring of operations, § 60.504, has been reserved pending development of monitor performance specifications. Monthly system leak inspections are required under § 60.502(j), but submission of leak inspection records is not required in the final regulation. However, under § 60.505(c), these records are required to be kept at the

terminal for at least 2 years. The requirement for quarterly reports of excess emissions under § 60.7(c) of the General Provisions is deleted under § 60.505(e).

Summary of Major Changes Since Proposal

Several changes of varying importance have been made to the standards since proposal. Most of the changes were made in response to comments, but some of them were made for the sake of clarity or consistency. One of the most significant of the changes dealt with proposed § 60.502(d), which required loadings of gasoline tank trucks to be restricted to vapor-tight tanks only, as evidenced by an annual vapor tightness test. Most of the comments on this requirement concerned the terminal operator's apparent liability for the condition of tank trucks owned by other parties. Several commenters felt that terminals would have to provide extra personnel at the loading racks to enforce this restriction. Section 60.502(d) [now § 60.502(e)] was expanded to delineate clearly the terminal owner or operator's responsibilities and to clarify that on-the-spot monitoring of product loadings would not be necessary. A terminal operator need only compare a tank identification number against the file of vapor tightness documentation within 2 weeks after a loading of that tank took place. If a terminal owner or operator checked his files and found that a nonvapor-tight truck was loaded without vapor tightness documentation, he would then be required to take steps assuring that no further loading into that tank truck took place until the proper vapor tightness documentation was received by the terminal. Thus, the final standard clarifies that a terminal owner or operator can comply with this part of the standard by cross-checking files and does not have to monitor loadings.

One paragraph about facilities with existing vapor processing equipment was added to § 60.502. The Agency has concluded that it is quite costly in light of the resulting emission reduction for an owner whose existing facility becomes subject to NSPS (e.g., through modification or reconstruction) to meet 35 mg/liter when the facility already has a system capable of meeting 80 mg/liter, but not 35 mg/liter. For this reason, EPA has added § 60.502(c), which permits affected facilities with such vapor control equipment to meet 80 mg/liter if construction or substantial rebuilding (i.e., "refurbishment") of that equipment commenced before the proposal date, December 17, 1980. This is based on the Administrator's judgment that BDT for these facilities is no further control, while BDT for facilities with vapor processing systems on which construction or refurbishment commenced after proposal is the replacement or add-on of technology that would enable the facility to achieve 35 mg/liter.

Several commenters objected to the requirement for excess emissions reports and to using an average monitored value as the basis for an excess emissions determination. Section 60.504, Monitoring of Operations, has been reserved pending the development and promulgation of performance specifications for continuous monitoring devices. Therefore, specific comments concerning the proposed continuous monitoring requirements cannot be addressed at this time. The Agency is currently investigating several types of simple, low-cost monitors for various types of vapor processors. After specifications have been selected, they will be proposed in a separate action in the Federal Register for public comment.

A new § 60.500(c) has been added to change the applicability date from the date of proposal to the date of promulgation for existing facilities commencing component replacement prior to the promulgation date for the purpose of complying with State or local regulations. Such facilities are not subject to the standards by means of the reconstruction provisions. New § 60.506 was added in response to commenters' concerns about the burden of accumulating records of component replacements at an existing source over the lifetime of the source for the purpose of determining reconstruction. Section 60.506(b) limits the time period for determination of reconstruction to 2 years and § 60.506(a) excludes frequently replaced components for consideration in applying the reconstruction provisions to bulk gasoline terminals.

In response to industry comments, a size cutoff by gasoline throughput was added to the definition of "bulk gasoline terminal" (only facilities handling more than 76,700 liters, or 20,000 gallons, per day are covered), to clarify that bulk plants served by ship or barge are not covered by these standards. Also, the word "wholesale" has been removed because the throughput cutoff should exclude retail outlets (service stations) from possible applicability.

The terminology used in the emission limits in the standard has changed since proposal. The emission limits are now expressed in terms of total organic compounds rather than VOC (VOC is the proportion of the organic compounds that is regarded as photochemically reactive). This change does not change the effect on stringency of the standard, but it does make the standard better reflect the intent behind the standard and the data base and test procedures used in establishing the standard.

The standard is intended to reduce emissions of VOC through the application of best demonstrated technology (BDT) (considering costs and other impacts), and the emission limits in the standard are designed to reflect the performance of BDT. The best demonstrated technologies applicable to bulk terminals do not selectively control VOC, but rather they control all organic compounds. Furthermore, the emission limits in the standard are based on test data and test procedures that measure total organic compounds, and the test methods used to determine compliance with the standard measure total organic compounds. Therefore, to reflect accurately the performance of the technologies selected as BDT and to be consistent with the data base and test methods upon which the emission limits are based, the emission limits in the proposed standard should have been expressed in terms of total organic compounds. To reflect the applicable technology and test methods, the emission limits in the promulgated standard are expressed in those terms. EPA is relying on control of total organic compounds as the best demonstrated surrogate for controlling volatile organic compounds, which react to form ozone in the atmosphere.

However, the test procedures in the proposed standard gave the owner or operator the option to subtract methane and ethane in determining compliance with the standard. Because the test procedures were proposed in this way and because the relative quantity of these compounds is expected to be small, the promulgated standard retains this option in the test procedures. The owner or operator may invoke this option only by using a method approved by the Administrator.

Summary of Environmental, Energy, Economic Impacts

The promulgated standards will reduce projected 1986 VOC emissions from affected bulk terminals from about 8,300 megagrams per year (Mg/yr) to about 2,600 Mg/yr, or 68 percent.

The promulgated standards are based on the use of carbon adsorption (CA) and thermal oxidation (TO) type vapor processors for the 35 mg/liter emission limit. TO systems emit a small quantity of carbon monoxide (CO) and oxides of nitrogen (NO_x), but since few oxidation

systems are expected to be installed, total emissions of CO and NO_x will be negligible.

Neither of these control systems uses water as a direct control medium, and so the water pollution impact will be minimal. Refrigeration (REF) systems, which may also be used to meet the standards, discharge a small amount of water which condenses in the system due to the humidity of the air. Organics are separated from the condensed water in an oil-water separator on the refrigeration unit. The excess water is subsequently handled by the bulk terminal's existing drainage system.

There will be no solid effluent from any of the control systems. CA systems may produce a small quantity of solid waste if the activated carbon must be replaced due to a loss in working capacity of the carbon beds. The worst-case nationwide waste production is estimated at about 50,000 kilograms (kg) per year, which represents a small solid waste impact.

All of the vapor processors considered in setting the standards consume electricity in the course of their operation, to power fans, dampers, pumps, compressors, valves, timers, and other miscellaneous components. However, all of the processors, except the thermal oxidizer, recover energy in the form of liquid gasoline. Therefore, while the power costs to operate control equipment to comply with the promulgated standards average about 25 percent higher than the power costs to comply with a typical SIP at a 950,000 liter per day terminal, the extra product recovery realized under these standards means that this terminal will experience a net energy savings which is equivalent to about 15,000 liters of gasoline per year greater than the SIP. The total net energy recovery experienced by the bulk terminal industry in the fifth year of the standards will be about 7.0 million liters of gasoline equivalent.

Compliance with these standards will result in net annualized costs in the bulk gasoline terminal industry of about $1.6 million by 1986. Cumulative capital costs of complying with the promulgated standards will amount to about $10.8 million by 1986. Net annualized and cumulative capital costs to the for-hire tank truck industry will total about $0.9 million and $1.4 million, respectively, by the fifth year of the standards. The total annualized cost for this standard would then be $2.5 million. This annualized cost, coupled with the estimated emmission reduction of 5,700 Mg/yr, results in a cost per unit emission reduction of $440/Mg. The percent increase in the price of gasoline necessary to offset costs of compliance with the promulgated standards will range from zero for certain larger terminals up to about 0.48 percent for the smallest terminals. The overall impact on national gasoline prices will be negligible. The environmental, energy, and economic impacts are discussed in greater detail in the BID, Volume II. Also discussed are all of the commenters' suggested changes in the impact calculations and the rationale for making some of these changes and not others.

The nationwide impact numbers presented here include a composite of impacts for new, modified, and reconstructed facilities in locations where States require the level of control recommended in the control techniques guideline document (CTG) and in locations where States have no control requirements. If an average size bulk terminal (950,000 liters/day gasoline throughput) subject to the standards due to modification or reconstruction were located in an area with State requirements equivalent to the level recommended by the CTG and the terminal had an existing vapor processing system which met these State requirements, no additional controls would be required. For the same size new terminal, the incremental annualized cost for a terminal using CA or TO would be negligible because the same basis control device could be used to meet either set of requirements. If a new, modified, or reconstructed terminal of the same size were located in an area with no State requirements, the uncontrolled emissions would be reduced by about 160 Mg/yr at an annualized cost of about $38,000, which is less than $240/Mg of VOC reduced.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** (45 FR 30686, May 9, 1980), of a meeting of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) to discuss the bulk gasoline terminal standards recommended for proposal. This meeting was held on June 5, 1980. The meeting was open to the public and each attendee was given an opportunity to comment on the recommended standards. The standards were proposed and published in the **Federal Register** on December 17, 1980, (45 FR 83126). The preamble to the proposed standards discussed the availability of the background information document, "Bulk Gasoline Terminals—Background Information for Proposed Standards," EPA-450/3-80-038a (BID, Volume I), which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID, Volume I, were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held in two sessions, on January 21 and 28, 1981, at Research Triangle Park, North Carolina. The hearings were open to the public and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from December 17, 1980, to March 20, 1981.

Forty-two comment letters were received and six interested parties testified at the public hearings concerning issues relative to the proposed standards of performance for bulk gasoline terminals. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards.

Major Comments on the Proposed Standards

Comments on the proposed standards were received from bulk gasoline terminal owners and operators, Federal agencies, State and local air pollution control agencies, trade associations, and air pollution control equipment suppliers. A detailed discussion of these comments and Agency responses can be found in the background information document for the promulgated standards (BID, Volume II), which is referred to in the ADDRESSES section of this preamble. The summary of comments and responses in the BID, Volume II, serves as the basis for the revisions which have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble.

Need for Standard

Several commenters recommended that the proposed standards be canceled and that no additional regulation be adopted. Instead, the State implementation plans (SIP's) should be relied upon to control VOC emissions from bulk gasoline terminals. One reason given was that gasoline demand is projected to stabilize or decline in the future, so that emissions from new, modified, or reconstructed sources should not present any increasing environmental hazard.

Other commenters felt that the additional emission reduction achieved under Alternative IV (35 mg/liter from processor plus vapor-tight tank trucks)

as opposed to Alternative II (80 mg/liter from processor plus vapor-tight tank trucks) would be insignificant. The commenters stated that the control limit of 80 mg/liter required by many SIP's has already reduced VOC emissions by 90 percent; the proposed 35 mg/liter limit would reduce nationwide bulk terminal VOC emissions by the fifth year by only an extremely small percentage. Due to these small reductions, these commenters felt that standards had been proposed simply because they are "technically feasible." Thus, the commenters felt EPA had not demonstrated, as required by Section 111, that new terminals will present a significant air pollution problem.

The Agency proposed these standards of performance under the authority of Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended. Section 111(b)(1) requires the Administrator to establish standards of performance for categories of new, modified, or reconstructed stationary sources which in the Administrator's judgment cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

The Ageney's listing of Petroleum Transportation and Marketing 23rd on the Priority List, as required under Section 111(f) (40 CFR 60.16, 44 FR 49222, August 21, 1979), reflects the Administrator's determination that this source category contributes significantly to air pollution. Before arriving at this decision, the Administrator considered the projected rate of growth in the number of facilities in this industry, the emission rates at uncontrolled facilities, and the emissions allowed under typical SIP's. EPA used the emissions forecasts in the BID, Volume I, and cited by the commenters, in analyzing these factors, and the Administrator has found no reason to alter the conclusions based on that analysis.

It is important to note that VOC is emitted by a wide variety of source categories. The emissions contribution from many categories with VOC emissions that appear small in comparison with the total VOC emitted by all source categories is nonetheless significant to ozone formation. This is because failure to control these sources to the level achievable by the best demonstrated technology would serve to undermine the Congressionally mandated effort to prevent further deterioration of air quality caused by additional ozone formation. Emission reductions from this source category also appear small because the projected number of affected facilities is only a small percentage (less than 5 percent) of the total number of terminals nationwide.

The Agency accounted for the projected demand for gasoline in the coming years in estimating the emission reduction achievable through the NSPS. Despite a leveling off or reduction in gasoline demand, there will still be a significant number of affected terminals which will result in significant emissions reduction under these standards. Although the small number of new terminals (five in the next 5 years) reflects this leveling off in product demand, the current industry trend is toward the consolidation of existing terminals rather than the construction of new terminals. As a result, estimates indicate that there will be as many as 50 modified or reconstructed terminals in the next 5 years.

Regulatory alternatives, reflecting different levels of control technology, were evaluated for these 55 affected facilities, and it was determined that the control technology was available, at a reasonable cost, to control emissions from new, modified, and reconstructed terminals. Relying only on the SIP's for this category would mean that many sources, in areas not requiring controls under SIP's will remain uncontrolled. It appeared reasonable, therefore, to require additional controls, for the affected facilities in both controlled and uncontrolled areas, that were technologically demonstrated to be both readily achievable and economically reasonable.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, an evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. The costs are utilized in an economic analysis that determines the affordability of controls in an unbiased study of the economic impact of controls on an industry.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, representatives from government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

The promulgated standards reflect application of the best demonstrated technology for new, modified, and reconstructed sources in the bulk terminal subcategory. While technical feasibility is a fundamental criterion for standard-seting, EPA considered additional factors, including cost, energy requirements, and other impacts, before arriving at the final standard. Based upon these factors, the Agency selected at proposal a control alternative which reflects Alternative IV. As explained in the preamble section on "Modification and Reconstruction," the Agency has revised the standard in response to these and other comments; the standards are now based upon a combination of Alternatives II and IV.

Several commenters were concerned that a number of their smaller loading facilities, typically considered as bulk plants, would be included under the definition of a terminal for purposes of this standard. These commenters felt a throughput cutoff should be added to the definition of a terminal.

To clarify the intended applicability of the NSPS, a definition of bulk terminal dependent upon a throughput cutoff has been included in § 60.501. The purpose of this definition is to exclude the smaller bulk plant. With this intention, a bulk terminal has been defined to have a gasoline throughput greater than 75,700 liters per day. The gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State, or local law. Reference to an enforceable condition allows a source to limit its maximum design throughput by limiting its hours of operation, or by controlling any other operating parameter. The only requirements are that this limitation be a part of an enforceable document and that the source maintain compliance with it. This document could be issued by any government entity as long as it was

discoverable by both EPA and any citizen as contemplated in Section 304 of the Clean Air Act. By obtaining such documentation, which would reflect a source's maximum expected actual throughput, ambiguities as to how one would determine throughput are eliminated. For example, a bulk plant which receives gasoline by barge, with a statement (documented in an enforceable permit) that they will not exceed a throughput of 15,140 liters/day (4,000 gal/day), would not be misconstrued as a bulk terminal.

Modification and Reconstruction

Several commenters were concerned that conversions being made to terminals to satisfy SIP control requirements, such as top-to-bottom loading conversions and installation of vapor control equipment, could subject these terminals to the more stringent requirements of these standards through the reconstruction provisions of 40 CFR 60.15. Also, the economic impact would be significant for these terminals since they have already made commitments toward complying with SIP limitations. It was suggested by some of the commenters that these conversions should be exempted from the reconstruction provisions (40 CFR 60.15).

The section entitled "Impacts of Regulatory Alternatives" in the preamble to the proposed standards discussed the environmental, costs, and economic impacts on bulk terminal facilities complying with the requirements of those standards. Included in the discussion were impacts on new, modified, and reconstructed facilities. The impacts estimated for the standards did not include any reconstructions resulting from application of State or local air pollution requirements. However, as several commenters pointed out, a large number of terminal facilities that the Agency did not project as affected could indeed become subject to the standards in the process of complying with such requirements. Thus, the preamble discussion suggested that existing facilities commencing component replacement in response to State or local requirements would not be subject to 40 CFR 60.15.

The Agency believes that this suggestion introduced some doubt as to the otherwise straightforward application of the reconstruction provisions to existing facilities undergoing such changes. Consequently, owners and operators making plans to install control systems at these facilities may have been misled to believe that stricter NSPS requirements might not apply, and may therefore not have considered the stricter NSPS requirements when designing their systems.

For this reason, the Administrator has determined that any facility that has commenced substantial component replacement in response to State or local emission standards after the applicability date (the proposal date—December 17, 1980) but prior to the date of promulgation will not be subject to these NSPS requirements by operation of the reconstruction provisions of 40 CFR 60.15. Under § 60.500(c), any component replacement program commenced (as defined in Section 60.2) before today's date, and determined by the Administrator to be necessitated by State or local bulk terminal regulations, will not subject a bulk terminal facility to the NSPS by means of the reconstruction provisions.

It should be noted, however, that 40 CFR 60.15 applies by straightforward application to any existing facility undergoing component replacement. Neither the language nor the purposes of that provision and the definition of "new source" in Section 111 supports exemptions based on the owner's intent in performing construction on the facility.

Because this preamble corrects the misimpression that Section 60.15 does not apply to facilities undergoing SIP component replacement, the Agency is applying that provision to SIP component replacement programs commenced *after* today's date. Of course, owners or operators performing reconstruction for other purposes, or modifications or new construction for *any* purpose, are still governed by the applicability date of December 17, 1980, contained in § 60.500(b).

Commenters also felt that EPA had greatly underestimated the number of existing terminals which would be affected by the modification and reconstruction provisions. At least 30 SIP's will contain bulk terminal vapor recovery requirements, and it was believed that conversion work performed at affected facilities would subject those facilities to the provisions of these standards.

Since most State of local regulation-related construction programs at bulk terminals will have commenced by the promulgation date, the change in the applicability date, in effect, excludes these terminals from the standards. Therefore, EPA's estimate at the time of proposal of 55 new, modified, or reconstructed terminals in 5 years is still considered a reasonable projection. The estimate of 5 new facilities and 50 modified or reconstructed facilities was based primarily on information obtained from oil companies through responses to Section 114 letter requests. Telephone conversations with several control agencies, oil companies, and terminal construction engineering firms provided supplementary information.

Many of the commenters stated that the interpretation of "reconstruction" is an unwarranted extension of EPA's past procedure in defining this provision and an illegal extension of EPA's authority under Section 111. They felt that the reconstruction provisions were meant to be applied to each capital construction project as it occurs, and not applied on a cumulative basis over an unlimited time period. The commenters felt that under the present interpretation of reconstruction every existing loading rack, including those in attainment areas, would, through ordinary maintenance and replacement of components, become a new source long before the end of its useful life. They concluded that the use of cumulative costs would be a tremendous administrative burden on the industry and EPA.

The Agency promulgated the reconstruction provisions to ensure that essentially new facilities due to reconstruction would be subject to "new source" performance standards. The reconstruction provisions were promulgated in 1975 (40 FR 5846), and EPA has applied these provisions consistently since that time. Further, the Agency's authority to subject reconstructed sources to new source standards of performance has not been questioned in any court decision.

If one considers the 50 percent cost factor which triggers reconstruction strictly on a project-by-project basis, a wide variety of interpretations can arise as to what a "project" entails. For example, a terminal with three top loading racks may convert one rack to bottom loading, and then 6 months later convert a second loading rack to bottom loading. If the two conversions were interpreted as separate projects, neither one would likely exceed the 50 percent replacement cost to trigger reconstruction. If, however, it was the terminal owner's original intent to convert both loading racks, the two conversions would be interpreted as one project and would probably constitute a reconstruction. In many cases, it would not be possible to determine the original intent of the terminal owner or operator. In order to reduce the number of subjective determinations concerning intent in these cases, the reconstruction provisions will be applied on a basis which considers the expenditures made

toward a facility over a fixed time period.

To eliminate the ambiguity in the current wording of § 60.15 and further the intent underlying Section 111 (as described above), the Agency is clarifying the meaning of "proposed" component replacements in § 60.15. Specifically, the Agency is interpreting "proposed" replacement components under § 60.15 to include components which are replaced pursuant to all continuous programs of component replacement which commence (but are not necessarily completed) within the period of time determined by the Agency to be appropriate for the individual NSP involved. The Agency is selecting a 2-year period as the appropriate period for purposes of the bulk gasoline terminal NSPS (§ 60.506(b)). Thus, the Agency will count toward the 50 percent reconstruction threshold the "fixed capital cost" of all depreciable components (except those described below) replaced pursuant to all continuous programs of reconstruction which commence within any 2-year period following proposal of these standards. In the administrator's judgment, the 2-year period provides a reasonable, objective method of determining whether an owner of bulk gasoline terminal facilities is actually "proposing" extensive component replacement, within the Agency's original intent in promulgating § 60.15.

The administrative effort to keep the required records should not be a burden on the industry. The recordkeeping required under this interpretation of reconstruction is the same as the recordkeeping that would be required under a strictly project-by-project interpretation. In either case, the dollar amount of the component replacements taking place at the facility must be determined and recorded. Section 6.15 defines the "fixed capital cost" of replacement components as the capital needed to provide all the "depreciable" components. By excluding nondepreciable components from consideration in calculating component replacement costs, this definition excludes many components that are replaced frequently to keep the plant in proper working order. There may, however, be some depreciable components that are replaced frequently for similar purposes. In the Agency's judgment, maintaining records of the repair or replacement of these items may constitute an unnecessary burden. Moreover, the Agency does not consider the replacement of these items an element of the turnover in the life of the facility concerning Congress when it enacted Section 111. Therefore, in accordance with 40 CFR 60.15(g), these standards (§ 60.506) will exempt certain frequently replace components, whether depreciable or nondepreciable, from consideration in applying the reconstruction provisions to bulk gasoline terminal facilities. The costs of these components will not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable entirely new facility" under § 60.15. In the Agency's judgment, these items are pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensors, vapor hoses, and grounding cables.

One commenter felt that if the proposed standards further limited allowable total organic compounds emissions from 80 mg/liter to 35 mg/liter of gasoline loaded, then over half of his terminals would experience "immediate operational constraints," since they are equipped with vapor processing units of the compression-refrigeration-absorption (CRA) or lean oil absorption (LOA) type, which EPA data indicate cannot meet the proposed 35 mg/liter limit.

The existing facilities described by the commenter would not be subject to the standards unless modification or reconstruction were commenced after the proposal date of December 17, 1980. For those facilities with existing vapor processing systems which become affected facilities under modification or reconstruction, the Administrator concluded that it was not reasonable for the owner or operator to replace or perform costly upgrading on existing vapor processing systems, in order to achieve the small incremental emission reduction which reflects the change from 80 mg/liter to 35 mg/liter. As an example, emissions from a 950,000 liter/day terminal would decrease about 15 Mg/year in the change from 80 to 35 mg/liter, at a net annualized cost of about $50,000 for replacement or add-on controls. In the Administrator's judgment, however, it is unreasonably costly to require such a facility to install the add-on technology that will achieve 35 mg/liter *only* if the facility began constructing or substantially rebuilding (i.e., "refurbishing") the control system before receiving notice December 17, 1980, that BDT for those facilities, were they later to come under NSPS, would likely be equipment capable of meeting 35 mg/liter.

By contrast, EPA considers it reasonable to apply the 35 mg/liter limit to a facility whose owner commenced construction or refurbishment of a control system not capable of meeting 35 mg/liter despite having received this notice. It is reasonable to expect such an owner to avoid the high cost of going from 80 mg/liter to 35 mg/liter simply by constructing or refurbishing the facility's control system with technology that would meet EPA's proposed 35 mg/liter limit and make later retrofit unnecessary. This is reasonable to require even of facilities with existing control systems constructed or refurbished after December 17, 1980, for the purpose of meeting an 80 mg/liter State limit.

For these reasons, EPA has added § 60.502(c), which permits affected facilities with such vapor control equipment to meet 80 mg/liter if construction or substantial rebuilding (i.e., "refurbishment") of that equipment commenced before the proposal date, December 17, 1980. This is based on the Administrator's judgment that BDT for these facilities is no further control, while BDT for facilities with vapor processing systems on which construction or refurbishment commenced after proposal is the technology that would enable the facility to achieve 35 mg/liter.

Definitions for "existing vapor processing system" and "refurbishment" were added to the regulation to indicate that if in any 2-year period following the date the facility becomes an affected facility the fixed capital cost of improvements or changes to an existing vapor processing system exceeds 50 percent of the cost of a comparable entirely new vapor processing system, the altered vapor processing system must then meet the 35 mg/liter limit. Consequently, refurbishment applies only to those systems which become extensively rebuilt over this period.

Several commenters felt that the interpretation of "modification" is overly broad because it may include altered facilities from which the overall emissions have not increased. A clarification was sought so that replacement of needed components that improve loading efficiencies would not be considered modifications unless they resulted in an increase in the average daily emissions. For example, the replacement of worn-out pumps with new higher capacity pumps would allow faster loading, increasing emissions on a kg/hour basis during peak loading periods, but not on a mg/liter basis, which is the measurement of the standard. In fact, the number of tank trucks loaded during a day would not

necessarily increase due to a faster loading rate.

Section 60.14(e)(2) was purposely included in the General Provisions to exclude from consideration under the modification provisions increases in emissions due to relatively small changes. If a change increases production capacity and yet does not result in a "capital expenditure" as defined in the definitions in the General Provisions, the change would not be considered a modification.

Economic Impact

Some of the commenters stated that many of the costs of compliance to industry presented in BID, Volume I, were seriously underestimated. Two reasons provided were that control systems necessary to achieve the proposed standard of performance would cost more than systems capable of meeting only the less stringent SIP emission limit, and the actual number for affected facilities would be greater than the estimate due to conversions resulting from SIP requirements.

Many control systems being installed under SIP programs are capable of controlling emissions below 35 mg/liter, the limit of the promulgated standards of performance. Test data show that, in their normal operating mode, carbon adsorption (CA) and thermal oxidation (TO) units can consistently operate well below the 35 mg/liter limit. Therefore, for CA and TO units there are no additional costs involved in meeting 35 mg/liter versus the units currently being installed to meet 80 mg/liter.

Test results on current refrigeration (REF) units show that only some of these units meet the 35 mg/liter limit. However, these systems were installed to comply with a limit at or near the 80 mg/liter limit contained in most SIP's. The major manufacturer of these systems has indicated that adjustments to operating parameters can be made which will increase the control efficiency of individual systems (docket item IV–E–32). Such adjustments would be likely to increase electrical costs. Cost increases of up to 50 percent were reported by the manufacturer (docket item IV–F–3). The assumption that costs would not increase in the case of CA and TO units in order to meet 35 mg/liter is still considered valid. However, since data show that state-of-the-art REF technology can meet the standard, at somewhat increased capital and operating cost levels from the average current system, and since a large segment of industry is presently using this form of control (approximately 25 percent of existing units are refrigeration units), the potential cost impact to industry, if current use patterns are maintained, was examined.

As discussed under the preamble section "Modification and Reconstruction," the vast majority of conversions necessary to comply with State or local regulations will have commenced before the revised applicability date, and, therefore, not be regulated under these standards. Only those few State or local regulation-related conversions which commence after the promulgation date will be affected. Thus, the estimate of 55 facilities affected in 5 years is still believed to represent a reasonable approximation, based on Section 114 letter responses from industry. The updated industry costs were used to recalculate the nationwide cost impact, with the costs of purchasing and operating continuous monitors added to these estimates. By 1986, the terminal and independent tank truck industries will spend about $12.2 million in capital investment, and the net annualized cost in the fifth year will be $2.5 million. The capital and annualized cost estimates have decreased since the original evaluation mainly because of re-analysis of loading rack top-to-bottom loading conversion costs and changes in the requirements for existing vapor processing systems. In the previous analysis, presented in the BID, Volume I, the costs for the top-to-bottom loading conversions were attributed to the standards for all affected top loading terminals in the nationwide cost determination. However, in the revised evaluation, the cost of top-to-bottom loading conversions (not as a result of vapor control requirements) which would trigger reconstruction were not included in the costs to comply with the promulgated standards. These costs would be incurred by the terminal owner regardless of the standards since the conversions were performed voluntarily.

One commenter felt that even the small cost per gallon of product necessary to comply with the standards would discourage an owner or operator from investing in conversion work which might make a terminal subject to the standards, and that this could make terminal closures more prevalent. In response to this and similar comments, the economic analysis which supported the proposal was reviewed and many cost estimates were updated. The results of both the original and revised economic analyses showed that for the two smallest model plants the standards could, in the worst case, have a significant negative impact on profitability in the unlikely absence of complete control cost pass-through.

In the original analysis on existing facilities both the 380,000 liter/day and 950,000 liter/day model plants (model plants 1 and 2) would encounter returns-on-investment (ROI's) of less than 11 percent, taken to be the minimum acceptable level. The revised analysis indicates that only a 380,000 liter/day top-loaded facility (projected to be only 2 or 3 affected facilities per year) would experience a significant decrease in profitability, with a post-control ROI range of 7.7 to 8.0 percent. A 950,000 liter/day terminal would still maintain a marginal profitability level with a post-control ROI range of 10.6 to 11.0 percent. However, the preceding impacts are worst-case scenarios and very unlikely to occur. Since the price increase necessary to offset the control costs is less than 0.5 percent, the most likely scenario will involve an impact with most of the control costs passed through and very little cost absorption. Under this scenario no existing terminals are expected to close. Industry profiles do forecast a trend away from new small bulk terminals to larger terminals; however, this is a result of previous technological advances and economies of scale and is not a result expected to be accelerated by the implementation of these standards.

Some commenters questioned the BID, Volume I, cost estimates associated with purchasing, installing, operating, and maintaining vapor control systems. In particular, most CA system costs and some REF system costs were pointed out as being underestimated.

Most carbon adsorption units are currently being produced by two manufacturers. The purchase costs used in the original cost analysis were received from one major manufacturer at the time the analysis was performed. After proposal, estimated costs were updated through contacts with both manufacturers. The average cost of installing a vapor processor was estimated as 85 percent of the initial purchase price of the unit, based on 14 actual installations. Values used to compute the average installation cost ranged from 37 to 147 percent. Since no trend in this percentage as a function of purchase cost or unit type was noted, a single value representing the average was selected. Consequently, some unit installation costs will be higher and some lower than those presented in the analysis. Installation costs submitted by one commenter averaged about 115 percent of the purchase price of the processor, which is consistent with the range of values considered in deriving EPA's 85 percent figure. Another commenter submitted data showing that

the typical installation cost for a REF unit at his terminals was $90,000, or 55 percent of the $165,000 purchase price. Again, this percentage falls within the range of values considered previously by the Agency.

Operating costs for all control technologies considered in developing the standards were calculated using electrical consumption data supplied by the system manufacturers. The REF unit purchase cost and electrical consumption figures used to develop impacts of the proposed standards applied to systems used to achieve the SIP limit of 80 mg/liter. The data have subsequently been reassessed using more current costs. The manufacturer of essentially all of the current REF units was contacted to obtain present purchase and operating figures which would be reflected for a system to meet the emission limit of 35 mg/liter. Unit models were selected for application to the four model plants, based on the parameter suggested by the manufacturer, peak hourly product loading. Models were selected with considerable excess capacity, so that cost estimates would be conservative. The power costs for current CA systems were calculated in the same way as those for REF systems, using updated manufacturers' information. The limited available field data on the operating costs of installed units generally correlate well with the calculated figures.

Emission Control Technology

Several commenters remarked that the technology to achieve the 35 mg/liter emission limit has not been demonstrated, because only a few short-term tests have been performed. These commenters stressed the necessity for data on continuous performance, and on the ability of the considered systems to achieve the emission limit over the long term.

Since the beginning of the standards development, the Agency has sought the most recent results of tests performed by oil companies and State agencies, in order to collect the best possible data base. Since all of the tested systems were installed in response to SIP limitations at or near the 80 mg/liter limit, oil company and system manufacturer technical representatives were consulted to determine the assumed design conditions for the installed systems and the collection potential of the various control technologies. Emission test results on several CA units tested between 1979 and 1981, representing over 30 days of testing, were received after proposal from four State agencies and one control system manufacturer. Outlet total organic compounds mass emissions measured in these tests ranged from 0.34 to 17.9 mg/liter, with 28 of the daily test values below 10 mg/liter. Three REF units owned by a single oil company in two States were tested in 1980 and 1981. Daily average emissions in these tests were 21.9, 22.6, and 41.8 mg/liter. These results support the observation that current REF units perform at various levels with respect to the 35 mg/liter limit. Since total organic compounds mass emissions are related to the condenser temperature maintained in these units, setting the thermostatic controls at different levels can produce a range of emission levels from the same control equipment. The current generation of REF units can be adjusted to maintain the low temperatures (approximately −84°C, or −120°F) required to achieve 35 mg/liter consistently. Recent tests of TO systems verify the ability of oxidation units to limit emissions to levels considerably below 35 mg/liter.

Even though the tests did not follow EPA procedures exactly, the recent test data collected since proposal of these standards demonstrate the ability of the best systems to achieve the required level of 35 mg/liter. The continuing ability of these systems to achieve this limit depends on their proper operation and maintenance. The costs of operating and maintaining CA, TO, and REF type vapor processors were considered in assessing the economic impact of the promulgated standards. As discussed earlier, the 80 mg/liter limit applied to facilities with existing vapor processors should be able to be met by any of the control equipment which was installed under SIP requirements.

Some commenters stated that it had not been shown by EPA that the proposed standards would be achievable under all the variable operating conditions that may exist throughout the industry. However, these commenters did not identify any specific variable operating conditions which they felt may affect emission levels, nor was any technical information included with the comments. The typical performance test on bulk terminal control systems does not monitor operating conditions and their possible effect on emissions, because generally all that is required in this test procedure is the measurement of outlet mass emissions over several hours. However, data were collected during the EPA-sponsored test program and variables (gasoline composition, vapor concentration, and peak loading levels) have been identified as having a possible effect on the mass emission level or control efficiency of the control technologies considered capable of achieving the limit of the standard.

Gasolines with different Reid vapor pressures (RVP) are marketed in different seasons of the year, in order to maintain approximately constant actual vapor pressure as the mean ambient temperature changes. Under winter conditions, therefore, mass emissions may be higher for some systems because of increased light ends in the inlet vapors. If CA and REF units are sized with sufficient collection area to meet the emission limit in winter, emissions in summer will then be well below the limit. TO systems are often designed to handle saturated streams stored in vapor holders, and should not be affected by the variable RVP. Tests of CA to TO units considered by the Agency show that the emission limit was achieved at various times of the year and, therefore, under various gasoline compositions.

Both CA and TO systems have been tested under a range of inlet VOC concentrations returned from tank trucks, and the test results indicate the ability of these technologies to achieve the limit of the standards under high inlet concentrations. Also, theoretical estimations and analyses for CA and REF systems have indicated that these systems will collect efficiently, and exhibit outlet emissions below 35 mg/liter, throughout the range of concentrations which will be experienced at new bulk terminals (docket items IV–A–2, IV–D–36, IV–D–38). Efficiencies, in fact, are likely to increase with increasing inlet concentration. TO systems are easily designed to handle saturated inlet streams.

Most control systems are designed for peak loading hours at a terminal, rather than daily throughput, because of the fluctuation in loading activity throughout the day. Thus, a properly sized unit that can handle peak periods should have improved performance during the remainder of the day.

It was concluded that the operational variables at a terminal are merely design variables which affect the selection and sizing of the vapor processor. No variables have been identified which would prevent these standards from being met on a consistent basis.

Several commenters felt that the proposed emission limit of 35 mg/liter for new vapor processors is too stringent for the current generation of vapor processors in use at bulk terminals. Some of the commenters stated that

certain types of processors would be unable to achieve this limit, whole others felt that the limit was unnecessarily stringent for any of the existing technologies. Alternate limits of 55 mg/liter and 80 mg/liter were suggested.

Standards of performance, in the form of numercial emission limits, are intended to reflect the degree of emission limitation achievable through application of the best adequately demonstated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements. Carbon adsorption vapor processors manufactured by both of the major suppliers have demonstrated the capability to achieve emission levels below 35 mg/liter on a regular basis. Also, thermal oxidation units have shown the capability to achieve 35 mg/liter, although some TO systems may require a vapor holder to achieve this limit reliably. Compression-oxidation hybrid systems have been found to achieve the same high control efficiences as the straight TO systems. In addition, test data, computer modeling, and the manufacturer's claims suggest the REF systems can be designed and operated to meet 35 mg/liter.

Based on a number of emission tests, EPA has identified carbon adsorption and thermal oxidation as the best demonstrated technologies (BDT) for controlling vapors from gasoline loading racks. Section 111 requires EPA to set numerical emission limits achievable through application of BDT (considering the statutory factors), even if by doing so the Agency precludes the use of less effective systems. Owners are nonetheless free to use any technology that will achieve the limit.

Some commenters referred to carbon bed temperature excursions at several CA unit installations during the summer of 1980. Due to the resulting extended shutdowns, one commenter felt that doubt had been cast on the ability of currently designed systems to maintain high efficiency consistently. Contacts were made by EPA with system manufacturers and oil industry representatives, to determine the apparent reasons for the six reported occurrences of carbon bed overheating. Discussions indicated that the overheating incidents were primarily the result of improper flow distribution and improper startup procedures resulting in the insufficient preloading of the virgin carbon in some new, larger units. Precautionary measures to prevent overheating including: (1) Complete conditioning of the virgin carbon to ensure that an adequate heel has been placed on the carbon to minimize subsequent high adsorption heat releases, and (2) sizing the unit to maintain proper vapor velocity and flow distribution through the carbon beds. According to the system manufacturers, overheating should not occur if these precautionary measures are employed (docket item IV-D-36).

Industry representatives have addressed the carbon bed overheating issue by incorporating emergency shutdown measures and bed cooling devices on newer systems. Two additional oil industry representatives indicated that, on any new carbon system ordered (and possibly retrofitted to existing systems), they will specify cooling provisions and additional temperature sensors. Since only 6 temperature excursion occurrences have been identified in the approximately 200 operating carbon systems, the overheating problem does not appear to be widespread. EPA agrees with the manufacturers and with industry representatives that an effort should be made to follow carefully the recommended startup and operational procedures to minimize the conditions which may tend to promote temperature excursions. The added costs of emergency shutdown and bed cooling provisions on the newest CA units have been incorporated in the revised cost analysis in estimating the control cost of the standards to the bulk terminal industry.

Two commenters felt that CA systems have several general operational problems and that this technology is still in the developmental stages. The first carbon adsorption system for bulk terminal vapor recovery was installed in November of 1978, and today the market is shared by two manufacturers with approximately 200 units in operation. Most types of vapor processors can be considered to be under development in the sense that continual design improvements are being made. Some problems with vacuum valve actuators and vacuum pump seals have occurred, as well as problems related to extremely cold weather operation. Many of these problems have been solved (docket item IV-E-53), and EPA has not been made aware of any remaining operational problems which would affect the ability of CA systems to comply with the promulgated standards.

Comments on refrigeration units concerned the ability of this technology to achieve the proposed standard of performance. Some commenters agreed that REF units could be designed and operated to achieve 35 mg/liter consistently, but felt that the added costs over current units would not be economically practical. The promulgated emission limit of 35 mg/liter was selected to reflect the performance of the best control systems, which test data showed to be the CA and TO technologies. The most current refrigeration systems have generally been installed to meet the 80 mg/liter limit and have achieved 35 mg/liter in only some instances, with emissions from most units slightly above the 35 mg/liter limit. Indications are that these units can be specified and operated to meet 35 mg/liter, at increased capital and operating costs over most current units. The capital costs for most sizes of REF units fall between the costs for TO and CA type units. Electrical costs for REF units are comparable to those for TO and CA units, except for the smaller bulk terminal sizes, where they are slightly higher. Detailed costs are presented in Appendix B of BID, Volume II.

Tank Truck Issues

Several commenters questioned EPA's legal authority to impose restrictions, i.e., retrofitting and vapor tightness testing, on gasoline tank trucks. They felt that trucks do not fall within the category of a stationary source and, therefore, cannot be regulated under Section 111. The commenters further stated that EPA could not regulate a mobile source directly or indirectly under Section 111. One commenter characterized the regulation of tank truck emissions as constituting "the taking of private property without cause, compensation, or due process."

For purposes of this NSPS, the stationary source, or affected facility, is the total of all bulk terminal loading racks loading liquid product into gasoline tank trucks. Those loading racks are essential to carrying out the activity known as product loading. While product loading involves both the affected facility and mobile equipment, including the tank truck, it is clearly a stationary activity, since it requires no movement from the affected facility site. Among the pollutants created by product loading are vapors forced from the tank truck as a direct result of the pumping of liquid product into the tank truck. Since escape of these vapors is caused by stationary activities at a stationary facility, they are "stationary source" emissions subject to regulation under Section 111—even though the tank trucks from which they escape during

that activity have the capability to move.

As indicated above, the tank truck is not included in the designation of the "affected facility" under these standards. The standards place responsibility on the terminal owner only, requiring the owner to restrict loadings to vapor-tight tank trucks equipped with compatible vapor recovery equipment. The regulation would not directly require either new or old tank trucks to be vapor-tight or equipped with certain types of hardware.

Section 111(a)(2) defines "stationary source" as any "building, structure, facility, or installation which emits or may emit any air pollutant." EPA identifies the "stationary source" as certain specified stationary equipment (termed the "affected facility") that "emits" a pollutant. In the Administrator's view, stationary equipment "emits" a pollutant if it causes that pollutant to enter the atmosphere.[1]

In the Administrator's view, affected facility emissions subject to regulation under Section 111 include *all* pollutants that enter the atmosphere as a result of the stationary industrial activities at the affected facility, even those that enter the atmosphere after contacting equipment with mobility. Stated differently, the test for whether emissions are "stationary source" emissions subject to regulation under Section 111 is whether the emissions are caused by a stationary facility during activities that require no movement from the facility, not whether the emissions escape to the atmosphere without touching equipment having the capability to move.

Interpreting "stationary source" emissions to include emissions resulting from stationary activities in which both the affected facility and some mobile equipment take part serves the intent of the statute. Congress enacted Section 111 for the "overriding purpose" of "prevent[ing] new pollution problems." S. Rep. No. 91-1196, 1970 *Leg. Hist.* at 416. The Senate Report states that Section 111 seeks to attain this goal by requiring control of new commercial and industrial establishments "to the maximum practicable degree regardless of their * * * industrial operations." *Id.* Similarly, the Report states that "maximum use of available means of preventing and controlling air pollution is essential" to the attainment of the goals of Section 111. *Id.* The legislative history thus indicates that Congress intend Section 111 to address emissions from all stationary operations at industrial establishments when the Agency can identify the maximum practicable degree of control for these emissions. To interpret Section 111(a)(2) so that emissions resulting from certain stationary activities involving the stationary source would not constitute "stationary source" emissions simply because those emissions pass through some equipment with the capability to move would be incompatible with that intent.

The Agency recognizes that promulgation of standards regulating loading racks as "stationary sources" may significantly affect tank truck owners and other segments of the petroleum marketing and transportation industry. The fact that standards within an agency's statutory authority indirectly affect nonregulated entities, however, does not in and of itself diminish the authority to set the standards. Nothing in the statute or its history indicates that, in the case at hand, the indirect impact that regulation of emissions from loading racks will have on certain tank truck owners deprives the Agency of its clear authority to set new source performance standards for this source category.

In fact, it is likely that most new source standards affect to some degree industries other than that to which the standards directly apply. The standards for electric utility steam generators, for instance (40 CFR 60.40a-49a, Subpart Da), significantly affect the coal mining and railroad industries. The impact on tank trucks of a requirement that certain bulk terminals load only into vapor-tight trucks equipped with compatible equipment does not differ in kind from the indirect impacts resulting from Subpart Da and other new source performance standards. Bulk terminals deal extensively with delivery vehicles. As a result, it is to be expected that regulation of bulk terminals would affect delivery vehicles in some manner.

The potential effect of the standards on tank truck owners does not amount to a denial of due process or an unconstitutional taking of property. Because the commenter did not elaborate on the specific bases for these claims of unconstitutionality, the Agency can respond only generally. The Clean Air Act reflects a congressional determination that air pollution has a substantial effect on interstate commerce and therefore may be regulated by Congress (and, through proper delegation, EPA) under the commerce clause. *District of Columbia v. Train*, 521 F.2d 971, 988 (D.C. Cir. 1975). It is unreasonable to suggest that regulation of emissions forced from the tank truck during loading bears no rational relationship to protection of public health and welfare, and thus violates the due process clause of the Fifth Amendment. There is a rational relationship between escape of these vapors and the public health and welfare, because these emissions contribute to ozone formation. *Sierra Club v. EPA*, 540 F.2d 1114, 1139 (D.C. Cir. 1976). There is also a proper legislative purpose underlying the requirements aimed at controlling these emissions. Moreover, the means the Agency has chosen, as discussed above, are reasonable and appropriate. *Id.*, at 1139 n.80 [citing *Heart of Atlanta Motel, Inc. v. United States*, 379 U.S. 241, 258-59 (1964)].

Nor do these standards transgress the takings prohibition in the Constitution. Given the substantial public interest in preserving clean air, tight restrictions may constitutionally be imposed on private property. *South Terminal Corp. v. EPA*, 504 F.2d 646, 678-80 (1st Cir. 1974). While this NSPS indirectly limits the uses of tank trucks, the limitation is not so extreme as to constitute an appropriation of the vehicles. *Sierra Club v. EPA, supra*, at 1140. This regulation affects only one of the tank truck uses available to the truck owner—loading at affected facilities. The right to use nonvapor-tight tank trucks at other facilities is neither extinguished nor transferred to someone else.

Several commenters felt that the terminal owner or operator should not have any responsibility for the vapor-tight status of for-hire tank trucks. The commenters felt that the terminal operator should not be required to police the testing and use of tank trucks which are owned by others.

Fugitive, or leakage, VOC emissions from tank trucks which occur during loading can be a significant emission source. Test data indicate that, on the average, a nonvapor-tight tank could lose 30 percent of the potential vapor transferred through leaks in dome covers and pressure-vacuum vents. The data further show that, by requiring the tanks which handle gasoline to pass an annual vapor tightness test, the average vapor loss due to leakage during the year between tests can be reduced to 10 percent of the potential vapors transferred. Fugitive VOC losses from tank trucks not only increase the

[1] EPA's authority to define the term "emits" in this way derives from Section 301 of the Act, as interpreted in the cases (see, e.g., *Alabama Power v. Costle*, 636 F.2d 323 (D.C. Cir. 1979)). In accordance with this provision, the Agency is interpreting the term "emits" broadly, to serve the broad purposes of Section 111 (described in the text below).

pollution problem but decrease the amount of product that can be reclaimed in vapor recovery equipment. The terminal owner or operator could lose as much as $2 in recovered product per loading into nonvapor-tight trucks. For a small 380,000 liter/day (100,000 gallon/day) terminal this could represent a daily loss of over $25. For a large 3,800,000 liter/day (1,000,000 gallon/day) terminal the losses could be over $250/day. Bulk terminal industry representatives agree that the vapor tightness requirement for tank trucks is a necessary provision of the regulation (docket items IV–E–19, IV–F–3).

The objections from the bulk terminal industry arise regarding the responsibility for assuring loadings are into vapor-tight tanks. The industry feels the responsibility should be on the tank truck operator, who in fact may be the terminal operator or oil company, or an independent who operates for-hire tank trucks. However, in order for the responsibility under new source standards to be on an independent tank truck operator, the tank truck would have to be part of the affected facility. The feasibility of including the tank truck as part of the affected facility was reviewed in the preamble to the proposed standards. It was determined that the best approach to controlling fugitive tank truck leakage was to make the standards applicable only to bulk terminals, with a requirement that affected terminals load only into truck-mounted tanks that have passed a vapor tightness test. Because tank trucks load primarily with equipment owned by the terminal owner, and on the property of the terminal owner, EPA believes it is reasonable to presume, for the purpose of this regulation, that these owners can exercise sufficient control over the source to justify making them responsible for the emissions therefrom.

EPA did not intend for terminal personnel to man the racks 24 hours per day, or actually observe the loading of every tank truck to verify that each truck had passed an annual vapor tightness test. EPA felt that requiring documentation on file that gasoline tank trucks operating out of the terminal had passed a vapor tightness test would provide a sufficient means of promoting loadings into vapor-tight tanks. Industry opposition is centered around the liability on the terminal owner for tank trucks he does not own. At unmanned, automated terminals, the terminal operator is usually not present and cannot determine which trucks are loading. The Agency realizes these limitations but believes that the vapor tightness requirement is necessary in order for these standards to be effective.

Changes to the vapor tightness requirement have been incorporated into the promulgated regulation to clarify that the standards do not require the terminal operator to monitor each tank truck loading. A requirement to log the tank identification number of all gasoline tank trucks loading at affected facilities has been incorporated into the final regulation. Since the quantity of product which passes through the terminal and its corresponding worth is very large, there is already considerable paperwork involved in tracking the products in and out of the terminal. The truck identification information could be recorded by the truck driver as part of the normal paperwork which already accompanies each loading. If the tank identification number is logged each time the tank is loaded, the owner can periodically cross-check the tank indentification number with the vapor tightness documentation on file at the terminal. This cross-checking is required within 2 weeks of the loading. If the terminal discovers that an unauthorized tank truck has received gasoline, the terminal operator notifies the tank owner, and takes steps to assure that the nonvapor-tight truck does not reload at the terminal until proper vapor tightness documentation is obtained. This notification must be documented and kept on file at the terminal. Methods of achieving this are available to the terminal owner or operator and could include revocation of loading privileges or contractural agreements between the terminal owner or operator and the truck owner or operator. However, EPA has not specified any particular method, to allow the terminal owner or operator the flexibility to meet the requirements, with minimum disruption to terminal operations. Section 111(h)(3) of the Clean Air Act provides that if the terminal owner, after notice and opportunity for public hearing, "establishes to the satisfaction of the Administrator that an alternative means of emission limitation will achieve a reduction in emission * * * at least equivalent to the reduction in emissions of such air pollutant" achieved under the tank truck vapor tightness requirement, the Administrator "shall permit the use of such alternatives * * *" Thus, the terminal owner is free, with EPA approval under Section 111(h)(3), to develop a different strategy for controlling fugitive emissions from tank trucks.

One commenter felt that an administrative burden would be created by a requirement to keep vapor tightness documentation for as many as 400 to 500 transport trucks using a given terminal. Several other commenters generally argued that the tank truck controls would represent an administrative burden, as well as being costly and inequitable.

The testing and maintenance of tank trucks for vapor tightness has been shown to have a significant effect in reducing total emissions during loading. Thus, this procedure has a very important function in bulk terminal VOC emissions limitation. The administrative burden of keeping the documentation on file would be minimal since the information would in most cases be supplied by the owner of for-hire tank trucks and the terminal would simply file the data. Cross-checking these files with tank identification numbers logged during loading should be a simple process and would not be an excessive burden. Furthermore, this filing and cross-checking would represent much less of a burden then the in-person monitoring by terminal personnel of each loading as it occurred.

Docket

The docket is an organized and complete file of information submitted, or otherwise considered, in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify and locate documents readily so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket, except for certain interagency review materials, will serve as the record in case of judicial review [Section 307(d)(7)(A)].

Miscellaneous

The effective date of this regulation is August 18, 1983. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (December 17, 1980).

As prescribed by Section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be

anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed within 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining BDT. The economic impact assessment is included in the background information documents for the proposed and promulgated standards (BID, Volumes I and II).

The Paperwork Reduction Act (PRA) of 1980 (Pub. L. 96–511) requires clearance from the Office of Mangement and Budget (OMB) of reporting and recordkeeping requirements that qualify as an "information collection request" under the PRA. For the purposes of OMB's review, and analysis of the burden associated with the reporting and recordkeeping requirements of this regulation has been made. During the first 2 years of this regulation, the average annual burden of the reporting and recordkeeping requirements would be 4.8 person-years, based on an average of 11 respondents per year. Information collection requirements contained in this regulation (§§ 60.502, 60.503, 60.505) have been approved by the OMB under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060–0006.

The Regulatory Flexibility Act of 1980 (RFA) requires that differential impacts on small businesses resulting from all Federal regulations be identified and analyzed. The RFA does not by its terms apply to regulations proposed prior to January 1, 1981. Consequently the RFA does not impose any requirements in the Agency's development of the bulk gasoline terminal NSPS (proposed December 17, 1980). However, the Agency has considered the economic impact of the standards on relatively small terminals and tank truck firms, and the economic analysis has since been reviewed in reference to the RFA. The definition of a small business in the bulk terminal industry (SIC 5171), according to the criterion to qualify for SBA loans, is a firm with less than $22 million in annual receipts. Approximately 50 to 60 percent of the bulk terminal industry can be considered as small businesses according to this criterion. In the for-hire tank truck industry (SICs 4212, 4213, and 4214), a small business is defined as a firm with less than $6.5 to $7 million in annual receipts. Approximately 60 percent of the for-hire tank truck industry can be considered as small businesses according to this criterion. The RFA further stipulates that the analysis must be prepared if 20 percent of the small businesses are significantly affected.

Five new terminals are expected to be constructed in the first five years, and approximately 50 facilities will become affected through modification or reconstruction. Of the 55 affected facilities, 15 terminals, a 27 percent share, can be considered small business entities (assuming Model Plant 1 approximates a small business), and so the 20 percent criterion is exceeded. The analysis concluded that significant impact for small business entities would occur only under the worst-case assumption of complete cost absorption. Under a more likely scenario, further analysis revealed no significant impact. Since the impact on small bulk terminal businesses is not expected to be significant, no Regulatory Flexibility Analysis is required for this industry sector.

Thirty-four model firms in the for-hire tank truck industry are expected to be affected by 1985. Twenty-three affected firms are expected to be small business entities, representing a 68 percent share, which exceeds the 20 percent criterion. The potential exists for a significant impact to occur in worst-case scenario if control costs are completely absorbed. The results from the return-on-transportation investment analysis not only suggested as significant worst-case impact, but that the impacts are more severe for the largest model trucking firms. A more likely scenario was analyzed and no significant economic impact was found. This scenario was based on the realistic assumption that most of the control costs will be passed through with very little cost absorption affecting the ROTI. Even under complete cost pass-through the price of gasoline increases at most by 0.03 percent. Since the impact on small independent tank truck firms is not expected to be significant, no Regulatory Flexibility Analysis is required for this industry sector.

Under Executive Order 12291, EPA is required to judge whether a regulation is a "major rule" and therefore subject to certain requirements of the Order. The Agency has determined this regulation will result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." The net annualized costs through the first 5 years of implementation, including depreciation and interest, are projected to be considerably below the threshold cost for defining a "major rule." Only negligible increases in the price of gasoline attributable to implementation of these standards are expected. The Agency has therefore concluded that this regulation is not a "major rule" under Executive Order 12291. In addition to the economic analysis, the Agency carefully examined the cost of various technical alternatives in terms of the emission reductions achieved. This was done for the range of configurations and facility sizes which are anticipated to be affected by the standard and, as described under the preamble section "Modification and Reconstruction," led to relaxation of the proposed standard for sources with SIP level controls in-place. The incremental cost of the final standard in terms of the incremental emission reduction achieved would range from a savings at certain medium to large size plants to a cost of approximately $1,100/Mg for a typical small facility. The total cost per unit of VOC emission reduction associated with this regulation is $440/Mg. This cost is consistent with that of other new source performance standards some of which cost $1,000/Mg to $2,000/Mg of VOC emission reduction, or higher.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel Sulfuric acid plants, Waste treatment and disposal, Zinc, Tires.

Dated: August 4, 1983.

William D. Ruckelshaus,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended as follows:

1. By adding a new subpart as follows:

Subpart XX—Standards of Performance for Bluk Gasoline Terminals

Sec.

60.500 Applicability and designation of affected facility.
60.501 Definitions.
60.502 Standards for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals.
60.503 Test methods and procedures.
60.504 [Reserved.]
60.505 Reporting and recordkeeping.
60.506 Reconstruction.

Authority: Sections 111 and 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart XX—Standards of Performance for Bulk Gasoline Terminals

§ 60.500 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is the total of all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks.

(b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, is subject to the provisions of this subpart.

(c) For purposes of this subpart, any replacement of components of an existing facility, described in paragraph § 60.500(a), commenced before August 18, 1983 in order to comply with any emission standard adopted by a State or political subdivision thereof will not be considered a reconstruction under the provisions of 40 CFR 60.15.

[Note: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technologies (BDT). The numerical emission limits in this standard are expressed in terms of total organic compounds. This emission limit reflects the performance of BDT.]

§ 60.501 Definitions.

The terms used in this subpart are defined in the Clean Air Act, in § 60.2 of this part, or in this section as follows:

"Bulk gasoline terminal" means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal, State or local law and discoverable by the Administrator and any other person.

"Continuous vapor processing system" means a vapor processing system that treats total organic compounds vapors collected from gasoline tank trucks on a demand basis without intermediate accumulation in a vapor holder.

"Existing vapor processing system" means a vapor processing system [capable of achieving emissions to the atmosphere no greater than 80 milligrams of total organic compounds per liter of gasoline loaded], the construction or refurbishment of which was commenced before December 17, 1980, and which was not constructed or refurbished after that date.

"Gasoline" means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater which is used as a fuel for internal combustion engines.

"Gasoline tank truck" means a delivery tank truck used at bulk gasoline terminals which is loading gasoline or which has loaded gasoline on the immediately previous load.

"Intermittent vapor processing system" means a vapor processing system that employs an intermediate vapor holder to accumulate total organic compounds vapors collected from gasoline tank trucks, and treats the accumulated vapors only during automatically controlled cycles.

"Loading rack" means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tank trucks.

"Refurbishment" means, with reference to a vapor processing system, replacement of components of, or addition of components to, the system within any 2-year period such that the fixed capital cost of the new components required for such component replacement or addition exceeds 50 percent of the cost of a comparable entirely new system.

"Total organic compounds" means those compounds measured according to the procedures in § 60.503.

"Vapor collection system" means any equipment used for containing total organic compounds vapors displaced during the loading of gasoline tank trucks.

"Vapor processing system" means all equipment used for recovering or oxidizing total organic compounds vapors displaced from the affected facility.

"Vapor-tight gasoline tank truck" means a gasoline tank truck which has demonstrated within the 12 preceding months that its product delivery tank will sustain a pressure change of not more than 750 pascals (75 mm of water) within 5 minutes after it is pressurized to 4,500 pascals (450 mm of water). This capability is to be demonstrated using the pressure test procedure specified in Reference Method 27.

§ 60.502 Standard for Volatile Organic Compound (VOC) emissions from bulk gasoline terminals.

On and after the date on which § 60.8(b) requires a performance test to be completed, the owner or operator of each bulk gasoline terminal containing an affected facility shall comply with the requirements of this section.

(a) Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.

(b) The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in paragraph (c) of this section.

(c) For each affected facility equipped with an existing vapor processing system, the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 80 milligrams of total organic compounds per liter of gasoline loaded.

(d) Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.

(e) Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:

(1) The owner or operator shall obtain the vapor tightness documentation described in § 60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.

(2) The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.

(3) The owner or operator shall cross-check each tank identification number obtained in (e)(2) of this section with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded.

(4) The terminal owner or operator shall notify the owner or operator of each nonvapor-tight gasoline tank truck loaded at the affected facility within 3 weeks after the loading has occurred.

(5) The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.

(6) Alternate procedures to those described in (e)(1) through (5) of this section for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.

(f) The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.

(g) The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

(h) The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in § 60.503(b).

(i) No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 4,500 pascals (450 mm of water).

(j) Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

(Approved by the Office of Management and Budget under control number 2060-0006)

§ 60.503 Test methods and procedures.

(a) Section 60.8(f) does not apply to the performance test procedures required by this subpart.

(b) For the purpose of determining compliance with § 60.502(h), the following procedures shall be used:

(1) Calibrate and install a pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ±2.5 mm of water precision.

(2) Connect the pressure measurement device to a pressure tap in the terminal's vapor collection system, located as close as possible to the connection with the gasoline tank truck.

(3) During the performance test, record the pressure every 5 minutes while a gasoline tank truck is being loaded, and record the highest instantaneous pressure that occurs during each loading. Every loading position must be tested at least once during the

(c) For the purpose of determining compliance with the mass emission limitations of § 60.502(b) and (c), the following reference methods shall be used:

(1) For the determination of volume at the exhaust vent:

(i) Method 2B for combustion vapor processing systems.

(ii) Method 2A for all other vapor processing systems.

(2) For the determination of total organic compounds concentration at the exhaust vent, Method 25A or 25B. The calibration gas shall be either propane or butane.

(d) Immediately prior to a performance test required for determination of compliance with § 60.502(b), (c), and (h), all potential sources of vapor leakage in the terminal's vapor collection system equipment shall be monitored for leaks using Method 21. The monitoring shall be conducted only while a gasoline tank truck is being loaded. A reading of 10,000 ppmv or greater as methane shall be considered a leak. All leaks shall be repaired prior to conducting the performance test.

(e) The test procedure for determining compliance with § 60.502(b) and (c) is as follows:

(1) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(2) The time period for a performance test shall be not less than 6 hours, during which at least 300,000 liters of gasoline are loaded. If the throughput criterion is not met during the initial 6 hours, the test may be either continued until the throughput criterion is met, or resumed the next day with another complete 6 hours of testing. As much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.

(3) For intermittent vapor processing systems:

(i) The vapor holder level shall be recorded at the start of the performance test. The end of the performance test shall coincide with a time when the vapor holder is at its original level.

(ii) At least two startups and shutdowns of the vapor processor shall occur during the performance test. If this does not occur under automatically controlled operation, the system shall be manually controlled.

(4) The volume of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested shall be determined. This volume may be determined from terminal records or from gasoline dispensing meters at each loading rack.

(5) An emission testing interval shall consist of each 5-minute period during the performance test. For each interval:

(i) The reading from each measurement instrument shall be recorded, and

(ii) The volume exhausted and the average total organic compounds concentration in the exhaust vent shall be determined, as specified in the appropriate test method. The average total organic compounds concentration shall correspond to the volume measurement by taking into account the sampling system response time.

(6) The mass emitted during each testing interval shall be calculated as follows:

$$M_{ei} = 10^{-6} K V_{ex} C_e$$

where:

M_{ei} = mass of total organic compounds emitted during testing interval i, mg.

V_{ex} = volume of air-vapor mixture exhausted, m^3, at standard conditions.

C_e = total organic compounds concentration (as measured) at the exhaust vent, ppmv.

K = density of calibration gas, mg/m^3, at standard conditions = 1.83×10^6 for propane = 2.41×10^6 for butane.

s = standard conditions, 20°C and 760 mm Hg.

(7) The total organic compounds mass emissions shall be calculated as follows:

$$E = \frac{\sum_{i}^{n} M_{ei}}{L}$$

where:

E = mass of total organic compounds emitted per volume of gasoline loaded, mg/liter.

M_{ei} = mass of total organic compounds emitted during testing interval i, mg.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

(f) The owner or operator may adjust the emission results to exclude the methane and ethane content in the exhaust vent by any method approved by the Administrator.

[Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)]

[Approved by the Office of Management and Budget under control number 2060-0006.]

§ 60.504 [Reserved].

§ 60.505 Reporting and recordkeeping.

(a) The tank truck vapor tightness documentation required under 160.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.

(b) The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:

(1) Test Title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.

(2) Tank Owner and Address.

(3) Tank Identification Number.

(4) Testing Location.

(5) Date of Test.

(6) Tester Name and Signature.

(7) Witnessing Inspector, if any: Name, Signature, and Affiliation.

(8) Test Results: Actual Pressure Change in 5 minutes, mm of water (average for 2 runs).

(c) A record of each monthly leak inspection required under § 60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:

(1) Date of Inspection.

(2) Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).

(3) Leak determination method.

(4) Corrective Action (date each leak repaired; reasons for any repair interval in excess of 15 days).

(5) Inspector Name and Signature.

(d) The terminal owner or operator shall keep documentation of all notifications required under § 60.502(e)(4) on file at the terminal for at least 2 years.

(e) [Reserved].

(f) The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

[Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)]

[Approved by the Office of Management and Budget under control number 2060-0006.]

§ 60.506 Reconstruction.

For purposes of this subpart:

(a) The cost of the following frequently replaced components of the affected facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable entirely new facility" under § 60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.

(b) Under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components [except components specified in § 60.506(a)] which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following December 17, 1980. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

[Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)]

2. By adding five new Reference Methods (Method 2A, Method 2B, Method 25A, Method 25B, and Method 27) to Appendix A as follows:

Appendix A—Reference Methods

* * * * *

Method 2A. Direct Measurement of Gas Volume Through Pipes and Small Ducts

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the measurement of gas flow rates in pipes and small ducts, either in-line or at exhaust positions, within the temperature range of 0 to 50°C.

1.2 Principle. A gas volume meter is used to measure gas volume directly. Temperature and pressure measurements are made to correct the volume to standard conditions.

2. *Apparatus.*

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

2.1 Gas Volume Meter. A positive displacement meter, turbine meter, or other direct volume measuring device capable of measuring volume to within 2 percent. The meter shall be equipped with a temperature gauge (± percent of the minimum absolute temperature) and a pressure gauge (±2.5 mm Hg). The manufacturer's recommended capacity of the meter shall be sufficient for the expected maximum and minimum flow rates at the sampling conditions. Temperature, pressure, corrosive characteristics, and pipe size are factors necessary to consider in choosing a suitable gas meter.

2.2 Barometer. A mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested, and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg per 30-meter elevation increase, or vice-versa for elevation decrease.

2.3 Stopwatch. Capable of measurement to within 1 second.

3. *Procedure.*

3.1 Installation. As there are numerous types of pipes and small ducts that may be subject to volume measurement, it would be difficult to describe all possible installation schemes. In general, flange fittings should be used for all connections wherever possible. Gaskets or other seal materials should be used to assure leak-tight connections. The volume meter should be located so as to avoid severe vibrations and other factors that may affect the meter calibration.

3.2 Leak Test. A volume meter installed at a location under positive pressure may be leak-checked at the meter connections by using a liquid leak detector solution containing a surfactant. Apply a small amount of the solution to the connections. If a leak exists, bubbles will form, and the leak must be corrected.

A volume meter installed at a location under negative pressure is very difficult to test for leaks without blocking flow at the inlet of the line and watching for meter movement. If this procedure is not possible, visually check all connections and assure tight seals.

3.3 Volume Measurement.

3.3.1 For sources with continuous, steady emission flow rates, record the initial meter volume reading, meter temperature(s), meter pressure, and start the stopwatch. Throughout the test period, record the meter temperature(s) and pressure so that average values can be determined. At the end of the test, stop the timer and record the elapsed time, the final volume reading, meter temperature(s), and pressure. Record the barometric pressure at the beginning and end of the test run. Record the data on a table similar to Figure 2A-1.

BILLING CODE 6560-50-M

Plant _____

Date _____ Run Number _____

Sample Location _____

Barometric Pressure mm Hg Start _____ Finish _____

Operators _____

Meter Number _____ Meter Calibration Coefficient _____

Last Date Calibrated _____

Time	Volume	Static pressure	Temperature	
Run/clock	Meter reading	mm Hg	°C	°K
Average				

Figure 2A-1. Volume flow rate measurement data.

3.3.2 For sources with noncontinuous, non-steady emission flow rates, use the procedure in 3.3.1 with the addition of the following: Record all the meter parameters and the start and stop times corresponding to each process cyclical or noncontinuous event.

4. *Calibration.*

4.1 Volume Meter. The volume meter is calibrated against a standard reference meter prior to its initial use in the field. The reference meter is a spirometer or liquid displacement meter with a capacity consistent with that of the test meter.

Alternately, a calibrated, standard pitot may be used as the reference meter in conjunction with a wind tunnel assembly. Attach the test meter to the wind tunnel so that the total flow passes through the test meter. For each calibration run, conduct a 4-point traverse along one stack diameter at a position at least eight diameters of straight tunnel downstream and two diameters upstream of any bend, inlet, or air mover. Determine the traverse point locations as specified in Method 1. Calculate the reference volume using the velocity values following the procedure in Method 2, the wind tunnel cross-sectional area, and the run time.

Set up the test meter in a configuration similar to that used in the field installation (i.e., in relation to the flow moving device). Connect the temperature and pressure gauges as they are to be used in the field. Conncet the reference meter at the inlet of the flow line, if appropriate for the meter, and begin gas flow through the system to condition the meters. During this conditioning operation, check the system for leaks.

The calibration shall be run over at least three different flow rates. The calibration flow rates shall be about 0.3, 0.6, and 0.9 times the test meter's rated maximum flow rate.

For each calibration run, the data to be collected include: reference meter initial and final volume readings, the test meter initial and final volume reading, meter average temperature and pressure, barometric pressure, and run time. Repeat the runs at each flow rate at least three times.

Calculate the test meter calibration coefficient, Y_m, for each run as follows:

$$Y_m = \frac{(V_{rf}-V_{ri})\,(t_r+273)}{(V_{mf}-V_{mi})(t_m+273)} \quad \frac{P_b}{(P_b+P_g)}$$

Eq. 2A–1

Y_m = Test volume meter calibration coefficient, dimensionless.
V_r = Reference meter volume reading, m^3.
V_m = Test meter volume reading, m^3.
t_r = Reference meter average temperature, °C.
t_m = Test meter average temperature, °C.
P_b = Barometric pressure, mm Hg.
P_g = Test meter average static pressure, mm Hg.
f = Final reading for run.
i = Initial reading for run.

Compare the three Y_m values at each of the flow rates tested and determine the maximum and minimum values. The difference between the maximum and minimum values at each flow rate should be no greater than 0.030. Extra runs may be required to complete this requirement. If this specification cannot be met in six successive runs, the test meter it not suitable for use. In addition, the meter coefficients should be between 0.95 and 1.05. If these specifications are met at all the flow rates, average all the Y_m values from runs meeting the specifications to obtain an average meter calibration coefficient, Y_m.

The procedure above shall be performed at least once for each volume meter. Thereafter, an abbreviated calibration check shall be completed following each field test. The calibration of the volume meter shall be checked by performing three calibration runs at a single, intermediate flow rate (based on the previous field test) with the meter pressure set at the average value encountered in the field test. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of flow as described above.

Note.—If the volume meter calibration coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the greater value of pollutant emission rate.

4.2 Temperature Gauge. After each test series, check the temperature gauge at ambient temperature. Use an American Society for Testing and Materials (ASTM) mercury-in-glass reference thermometer, or equivalent, as a reference. If the gauge being checked agrees within 2 percent (absolute temperature) of the reference, the temperature data collected in the field shall be considered valid. Otherwise, the test data shall be considered invalid or adjustments of the test results shall be made, subject to the approval of the Administrator.

4.3 Barometer. Calibrate the barometer used against a mercury barometer prior to the field test.

5. *Calculations.*

Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation.

5.1 Nomenclature

P_b = Barometric pressure, mm Hg.
P_g = Average static pressure in volume meter, mm Hg.
Q_s = Gas flow rate, m^3/min, standard conditions.
T_m = Average absolute meter temperature, °K.
V_m = Meter volume reading, m^3.
Y_m = Average meter calibration coefficient, dimensionless.
f = Final reading for test period.
i = Initial reading for test period.
s = Standard conditions, 20° C and 760 mm Hg.
Θ = Elapsed test period time, min.

5.2 Volume.

$$V_{ms} = 0.3853\, Y_m\,(V_{mf}-V_{mi})\,\frac{(P_b+P_g)}{T_m}$$

Eq. 2A–2

5.3 Gas Flow Rate.

$$Q_s = \frac{V_{ms}}{\Theta}$$

Eq. 2A–3

6. *Bibliography.*

6.1 Rom, Jerome J. Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment. U.S. Environmental Protection Agency. Research Triangle Park, N.C. Publication No. APTD-0576. March 1972.

6.2 Wortman, Martin, R. Vollaro, and P.R. Westlin. Dry Gas Volume Meter Calibrations. Source Evaluation Society Newsletter. Vol. 2, No. 2. May 1977.

6.3 Westlin, P.R. and R.T. Shigehara. Procedure for Calibrating and Using Dry Gas Volume Meters as Calibration Standards. Source Evaluation Society Newsletter. Vol. 3, No. 1. February 1978.

Method 2B—Determination of Exhaust Gas Volume Flow Rate From Gasoline Vapor Incinerators

Applicability and Principle

1.1 Applicability. This method applies to the measurement of exhaust volume flow rate from incinerators that process gasoline vapors consisting primarily of alkanes, alkenes, and/or arenes (aromatic hydrocarbons). It is assumed that the amount of auxiliary fuel is negligible.

1.2 Principle. The incinerator exhaust flow rate is determined by carbon balance. Organic carbon concentration and volume flow rate are measured at the incinerator inlet. Organic carbon, carbon dioxide (CO_2), and carbon monoxide (CO) concentrations are measured at the outlet. Then the ratio of total carbon at the incinerator inlet and outlet is multiplied by the inlet volume to determine the exhaust volume and volume flow rate.

2. *Apparatus.*

2.1 Volume Meter. Equipment described in Method 2A.

2.2 Organic Analyzer (2). Equipment described in Method 25A or 25B.

2.3 CO Analyzer. Equipment described in Method 10.

2.4 CO_2 Analyzer. A nondispersive infrared (NDIR) CO_2 analyzer and supporting equipment with comparable specifications as CO analyzer described in Method 10.

3. *Procedure.*

3.1 Inlet Installation. Install a volume meter in the vapor line to incinerator inlet according to the procedure in Method 2A. At the volume meter inlet, install a sample probe as described in Method 25A. Connect to the probe a leak-tight, heated (if necessary to prevent condensation) sample line (Stainless steel or equivalent) and an organic analyzer system as described in Method 25A or 25B.

3.2 Exhaust Installation. Three sample analyzers are required for the incinerator exhaust: CO_2, CO, and organic analyzers. A sample manifold with a single sample probe may be used. Install a sample probe as described Method 25A. Connect a leak-tight heated sample line to the sample probe. Heat the sample line sufficiently to prevent any condensation.

3.3 Recording Requirements. The output of each analyzer must be permanently recorded on an analog strip chart, digital recorder, or other recording device. The chart speed or number of readings per time unit

must be similar for all analyzers so that data can be correlated. The minimum data recording requirement for each analyzer is one measurement value per minute.

3.4 Preparation. Prepare and calibrate all equipment and analyzers according to the procedures in the respective methods. For the CO_2 analyzer, follow the procedures described in Method 10 for CO analysis substituting CO_2 calibration gas where the method calls for CO calibration gas. The span value for the CO_2 analyzer shall be 15 percent by volume. All calibration gases must be introduced at the connection between the probe and the sample line. If a manifold system is used for the exhaust analyzers, all the analyzers and sample pumps must be operating when the calibrations are done. Note: For the purposes of this test, methane should not be used as an organic calibration gas.

3.5 Sampling. At the beginning of the test period, record the initial parameters for the inlet volume meter according to the procedures in Method 2A and mark all of the recorder strip charts to indicate the start of the test. Continue recording inlet organic and exhaust CO_2, CO, and organic concentrations throughout the test. During periods of process interruption and halting of gas flow, stop the timer and mark the recorder strip charts so that data from this interruption are not included in the calculations. At the end of the test period, record the final parameters for the inlet volume meter and mark the end on all of the recorder strip charts.

3.6 Post Test Calibrations. At the conclusion of the sampling period, introduce the calibration gases as specified in the respective reference methods. If an analyzer output does not meet the specifications of the method, invalidate the test data for the period. Alternatively, calculate the volume results using initial calibration data and using final calibration data and report both resulting volumes. Then, for emissions calculations, use the volume measurement resulting in the greatest emission rate or concentration.

4. Calculations.

Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation.

4.1 Nomenclature

CO_s = Mean carbon monoxide concentration in system exhaust, ppmv.

CO_{2s} = Mean carbon dioxide concentration in system exhaust, ppmv.

HC_s = Mean organic concentration in system exhaust as defined by the calibration gas, ppmv.

HC_i = Mean organic concentration in system inlet as defined by the calibration gas, ppmv.

K = Calibration gas factor = 2 for ethane calibration gas.
= 3 for propane calibration gas.
= 4 for butane calibration gas.
= Appropriate response factor for other calibration gas.

V_{ss} = Exhaust gas volume, M^3.

V_{is} = Inlet gas volume, M^3.

Q_{ss} = Exhaust gas volume flow rate, m^3/min.

Q_{is} = Inlet gas volume flow rate, m^3/min.

θ = Sample run time, min.

s = Standard Conditions: 20°C, 760 mm Hg.

300 = Estimated concentration of ambient CO_2, ppmv. (CO_2 concentration in the ambient air may be measured during the test period using an NDIR and the mean value substituted into the equation.)

4.2 Concentrations. Determine mean concentration of inlet organics, outlet CO_2, outlet CO, and outlet organics according to the procedures in the respective methods and the analyzers' calibration curves, and for the time intervals specified in the applicable regulations. Concentrations should be determined on a parts per million by volume (ppmv) basis.

4.3 Exhaust Gas Volume. Calculate the exhaust gas volume as follows:

$$V_{ss} = V_{is} \frac{K(HC_i)}{K(HC_s) + CO_{2s} - 300}$$

Eq. 2B–1

4.4 Exhaust Gas Volume Flow Rate. Calculate the exhaust gas volume flow rate as follows:

$$Q_{ss} = \frac{V_{ss}}{\theta}$$

Eq. 2B–2

5. Bibliography.

5.1 Measurement of Volatile Organic Compounds. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. 27711. Publication No. EPA–450/2–78–041. October 1978. p. 55.

* * * * *

Method 25A—Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

1. Applicability and Principle.

1.1 Applicability. This method applies to the measurement of total gaseous organic concentration of vapors consisting primarily of alkanes, alkenes, and/or arenes (aromatic hydrocarbons). The concentration is expressed in terms of propane (or other appropriate organic calibration gas) or in terms of carbon.

1.2 Principle. A gas sample is extracted from the source through a heated sample line, if necessary, and glass fiber filter to a flame ionization analyzer (FIA). Results are reported as volume concentration equivalents of the calibration gas or as carbon equivalents.

2. Definitions.

2.1 Measurement System. The total equipment required for the determination of the gas concentration. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of the system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzer from the effects of the stack effluent.

2.1.2 Organic Analyzer. That portion of the system that senses organic concentration and generates an output proportional to the gas concentration.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations. The span value is established in the applicable regulation and is usually 1.5 to 2.5 times the applicable emission limit. If no span value is provided, use a span value equivalent to 1.5 to 2.5 times the expected concentration. For convenience, the span value should correspond to 100 percent of the recorder scale.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Zero Drift. The difference in the measurement system response to a zero level calibration gas before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

2.5 Calibration Drift. The difference in the measurement system response to a mid-level calibration gas before and after a stated period of operation during which no unscheduled maintenance, repair or adjustment took place.

2.6 Response Time. The time interval from a step change in pollutant concentration at the inlet to the emission measurement system to the time at which 95 percent of the corresponding final value is reached as displayed on the recorder.

2.7 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

3. Apparatus.

A schematic of an acceptable measurement system is shown in Figure 25A–1. The essential components of the measurement system are described below:

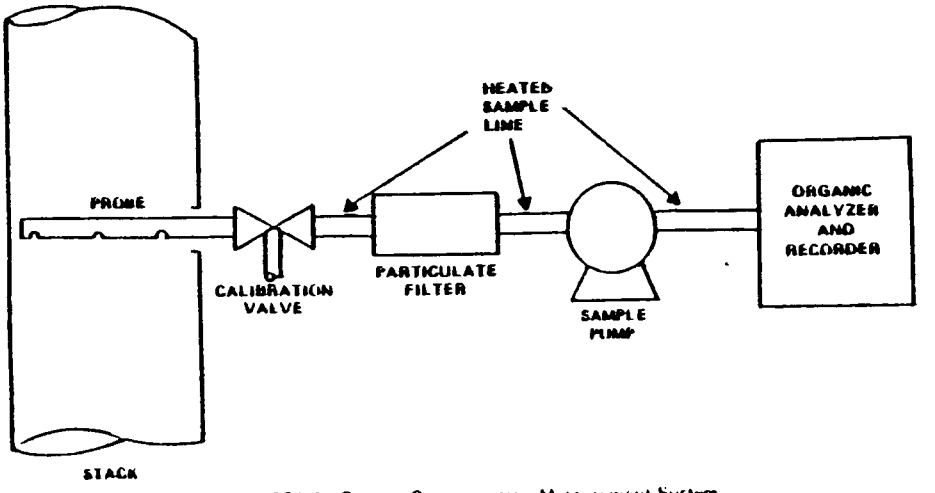

Figure 25A-1 Organic Concentration Measurement System.

3.1 Organic Concentration Analyzer. A flame ionization analyzer (FIA) capable of meeting or exceeding the specifications in this method.

3.2 Sample Probe. Stainless steel, or equivalent, three-hole rake type. Sample holes shall be 4 mm in diameter or smaller and located at 16.7, 50, and 83.3 percent of the equivalent stack diameter. Alternatively, a single opening probe may be used so that a gas sample is collected from the centrally located 10 percent area of the stack cross-section.

3.3 Sample Line. Stainless steel or Teflon* tubing to transport the sample gas to the analyzers. The sample line should be heated, if necessary, to prevent condensation in the line.

3.4 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the analyzers is recommended. Other methods, such as quick-connect lines, to route calibration gas to the analyzers are applicable.

3.5 Particulate Filter. An in-stack or an out-of-stack glass fiber filter is recommended if exhaust gas particulate loading is significant. An out-of-stack filter should be heated to prevent any condensation.

3.6 Recorder. A strip-chart recorder, analog computer, or digital recorder for recording measurement data. The minimum data recording requirement is one measurement value per minute. Note: This method is often applied in highly explosive areas. Caution and care should be exercised in choice of equipment and installation.

4. Calibration and Other Gases.

Gases used for calibrations, fuel, and combustion air (if required) are contained in compressed gas cylinders. Preparation of calibration gases shall be done according to the procedure in Protocol No. 1, listed in Reference 9.2. Additionally, the manufacturer of the cylinder should provide a recommended shelf life for each calibration gas cylinder over which the concentration does not change more than ±2 percent from the certified value. For calibration gas values not generally available (i.e., organics between 1 and 10 percent by volume), alternative methods for preparing calibration gas mixtures, such as dilution systems, may be used with prior approval of the Administrator.

Calibration gases usually consist of propane in air or nitrogen and are determined in terms of the span value. Organic compounds other than propane can be used following the above guidelines and making the appropriate corrections for response factor.

4.1 Fuel. A 40 percent H_2/60 percent He or 40 percent H_2/60 percent N_2 gas mixture is recommended to avoid an oxygen synergism effect that reportedly occurs when oxygen concentration varies significantly from a mean value.

4.2 Zero Gas. High purity air with less than 0.1 parts per million by volume (ppmv) of organic material (propane or carbon equivalent) or less than 0.1 percent of the span value, whichever is greater.

4.3 Low-level Calibration Gas. An organic calibration gas with a concentration equivalent to 25 to 35 percent of the applicable span value.

4.4 Mid-level Calibration Gas. An organic calibration gas with a concentration equivalent to 45 to 55 percent of the applicable span value.

4.5 High-level Calibration Gas. An organic calibration gas with a concentration equivalent to 80 to 90 percent of the applicable span value.

5. Measurement System Performance Specifications.

5.1 Zero Drift. Less than ±3 percent of the span value.

5.2 Calibration Drift. Less than ±3 percent of span value.

5.3 Calibration Error. Less than ±5 percent of the calibration gas value.

6. Pretest Preparations.

6.1 Selection of Sampling Site. The location of the sampling site is generally specified by the applicable regulation or purpose of the test; i.e., exhaust stack, inlet line, etc. The sample port shall be located at least 1.5 meters or 2 equivalent diameters (whichever is less) upstream of the gas discharge to the atmosphere.

6.2 Location of Sample Probe. Install the sample probe so that the probe is centrally located in the stack, pipe, or duct and is sealed tightly at the stack port connection.

6.3 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing the sample interface and the organic analyzer. Make the system operable.

FIA equipment can be calibrated for almost any range of total organics concentrations. For high concentrations of organics (>1.0 percent by volume as propane) modifications to most commonly available analyzers are necessary. One accepted method of equipment modification is to decrease the size of the sample to the analyzer through the use of a smaller diameter sample capillary. Direct and continuous measurement of organic concentration is a necessary consideration when determining any modification design.

6.4 Calibration Error Test. Immediately prior to the test series, (within 2 hours of the start of the test) introduce zero gas and high-level calibration gas at the calibration valve assembly. Adjust the analyzer output to the appropriate levels, if necessary. Calculate the predicted response for the low-level and mid-level gases based on a linear response line between the zero and high-level responses. Then introduce low-level and mid-level calibration gases successively to the measurement system. Record the analyzer responses for low-level and mid-level calibration gases and determine the differences between the measurement system responses and the predicted responses. These differences must be less than 5 percent of the respective calibration gas value. If not, the measurement system is not acceptable and must be replaced or repaired prior to testing. No adjustments to the measurement system shall be conducted after the calibration and before the drift check (Section 7.3). If adjustments are necessary before the completion of the test series, perform the drift checks prior to the required adjustments and repeat the calibration following the adjustments. If multiple electronic ranges are to be used, each additional range must be checked with a mid-level calibration gas to verify the multiplication factor.

6.5 Response Time Test. Introduce zero gas into the measurement system at the calibration valve assembly. When the system output has stabilized, switch quickly to the high-level calibration gas. Record the time from the concentration change to the measurement system response equivalent to 95 percent of the step change. Repeat the test three times and average the results.

7. Emission Measurement Test

7.1 Organic Measurement. Begin sampling at the start of the test period, recording time and any required process information as appropriate. In particular, note on the recording chart periods of process interruption or cyclic operation.

7.2 Drift Determination. Immediately following the completion of the test period and hourly during the test period, reintroduce the zero and mid-level calibration gases, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after both the zero and calibration drift checks are made.) Record the analyzer response. If the drift values exceed the specified limits, invalidate the test results preceding the check and repeat the test following corrections to the measurement system. Alternatively, recalibrate the test measurement system as in Section 6.4 and report the results using both sets of calibration data (i.e., data determined prior to the test period and data determined following the test period).

8. Organic Concentration Calculations.

Determine the average organic concentration in terms of ppmv as propane or other calibration gas. The average shall be determined by the integration of the output recording over the period specified in the applicable regulation.

If results are required in terms of ppmv as carbon, adjust measured concentrations using Equation 25A–1.

$$C_c = K\,C_{meas}$$

Eq. 25A–1

Where:

C_c = Organic concentration as carbon, ppmv.

C_{meas} = Organic concentration as measured, ppmv.

K = Carbon equivalent correction factor.

K = 2 for ethane.

K = 3 for propane.

K = 4 for butane.

K = Appropriate response factor for other organic calibration gases.

9. Bibliography.

9.1 Measurement of Volatile Organic Compounds—Guideline Series. U.S. Environmental Protection Agency. Research Triangle Park, N.C. Publication No. EPA–450/2–78–041. June 1978. p. 46–54.

9.2 Traceability Protocol for Establishing True Concentrations of Gases Used for

* Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

Calibration and Audits of Continuous Source Emission Monitors (Protocol No. 1). U.S. Environmental Protection Agency, Environmental Monitoring and Support Laboratory. Research Triangle Park, N.C. June 1978.

9.3 Gasoline Vapor Emission Laboratory Evaluation—Part 2. U.S. Environmental Protection Agency. Office of Air Quality Planning and Standards. Research Triangle Park, N.C. EMB Report No. 75-GAS-6. August 1975.

Method 25B—Determination of Total Gaseous Organic Concentration Using a Nondispersive Infrared Analyzer

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the measurement of total gaseous organic concentration of vapors consisting primarily of alkanes. (Other organic materials may be measured using the general procedure in this method, the appropriate calibration gas, and an analyzer set to the appropriate absorption band.) The concentration is expressed in terms of propane (or other appropriate organic calibration gas) or in terms of carbon.

1.2 Principle. A gas sample is extracted from the source through a heated sample line, if necessary, and glass fiber filter to a nondispersive infrared analyzer (NDIR). Results are reported as volume concentration equivalents of the calibration gas or as carbon equivalents.

2. *Definitions.*

The terms and definitions are the same as for Method 25A.

3. *Apparatus.* The apparatus are the same as for Method 25A with the exception of the following:

3.1 Organic Concentration Analyzer. A nondispersive infrared analyzer designed to measure alkane organics and capable of meeting or exceeding the specifications in this method.

4. *Calibration Gases.*

The calibration gases are the same as are required for Method 25A, Section 4. No fuel gas is required for an NDIR.

5. *Measurement System Performance Specifications.*

5.1 Zero Drift. Less than ±3 percent of the span value.

5.2 Calibration Drift. Less than ±3 percent of the span value.

5.3 *Calibration Error.* Less than ±5 percent of the calibration gas valve.

6. *Pretest Preparations.*

6.1 Selection of Sampling Site. Same as in Method 25A, Section 6.1.

6.2 Location of Sampling Probe. Same as in Method 25A, Section 6.2.

6.3 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing the sample interface and the organic analyzer. Make the system operable.

6.4 Calibration Error Test. Same as in Method 25A, Section 6.4.

6.5 Response Time Test Procedure. Same as in Method 25A, Section 6.4.

7. *Emission Measurement Test Procedure.*

Proceed with the emission measurement immediately upon satisfactory completion of the calibration.

7.1 Organic Measurement. Same as in Method 25A, Section 7.1.

7.2 Drift Determination. Same as in Method 25A, Section 7.2.

8. *Organic Concentration Calculations.*

The calculations are the same as in Method 25A, Section 8.

9. *Bibliography.*

The bibliography is the same as in Method 25A, Section 9.

Method 27—Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test

1. *Applicability and Principle.*

1.1 Applicability. This method is applicable for the determination of vapor tightness of a gasoline delivery tank which is equipped with vapor collection equipment.

1.2 Principle. Pressure and vacuum are applied alternately to the compartments of a gasoline delivery tank and the change in pressure or vacuum is recorded after a specified period of time.

2. *Definitions and Nomenclature.*

2.1 Gasoline. Any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater which is used as a fuel for internal combustion engines.

2.2 Delivery tank. Any container, including associated pipes and fittings, that is attached to or forms a part of any truck, trailer, or railcar used for the transport of gasoline.

2.3 Compartment. A liquid-tight division of a delivery tank.

2.4 Delivery tank vapor collection equipment. Any piping, hoses, and devices on the delivery tank used to collect and route gasoline vapors either from the tank to a bulk terminal vapor control system or from a bulk plant or service station into the tank.

2.5 Time period of the pressure or vacuum test (t). The time period of the test, as specified in the appropriate regulation, during which the change in pressure or vacuum is monitored, in minutes.

2.6 Initial pressure (P_i). The pressure applied to the delivery tank at the beginning of the static pressure test, as specified in the appropriate regulation, in mm H_2O.

2.7 Initial vacuum (V_i). The vacuum applied to the delivery tank at the beginning of the static vacuum test, as specified in the appropriate regulation, in mm H_2O.

2.8 Allowable pressure change (Δp). The allowable amount of decrease in pressure during the static pressure test, within the time period t, as specified in the appropriate regulation, in mm H_2O.

2.9 Allowable vacuum change (Δv). The allowable amount of decrease in vacuum during the static vacuum test, within the time period t, as specified in the appropriate regulation, in mm H_2O.

3. *Apparatus.*

3.1 Pressure source. Pump or compressed gas cylinder of air or inert gas sufficient to pressurize the delivery tank to 500 mm H_2O above atmospheric pressure.

3.2 Regulator. Low pressure regulator for controlling pressurization of the delivery tank.

3.3 Vacuum source. Vacuum pump capable of evacuating the delivery tank to 250 mm H_2O below atmospheric pressure.

3.4 Pressure-vacuum supply hose.

3.5 Manometer. Liquid manometer, or equivalent instrument, capable of measuring up to 500 mm H_2O gauge pressure with ±2.5 mm H_2O precision.

3.6 Pressure-vacuum relief valves. The test apparatus shall be equipped with an in-line pressure-vacuum relief valve set to activate at 675 mm H_2O above atmospheric pressure or 250 mm H_2O below atmospheric pressure, with a capacity equal to the pressurizing or evacuating pumps.

3.7 Test cap for vapor recovery hose. This cap shall have a tap for manometer connection and a fitting with shut-off valve for connection to the pressure-vacuum supply hose.

3.8 Caps for liquid delivery hoses.

4. *Pretest Preparations.*

4.1 Summary. Testing problems may occur due to the presence of volatile vapors and/or temperature fluctuations inside the delivery tank. Under these conditions, it is often difficult to obtain a stable initial pressure at the beginning of a test, and erroneous test results may occur. To help prevent this, it is recommended that, prior to testing, volatile vapors be removed from the tank and the temperature inside the tank be allowed to stabilize. Because it is not always possible to attain completely these pretest conditions a provision to ensure reproducible results is included. The difference in results for two consecutive runs must meet the criterion in Sections 5.2.5 and 5.3.5.

4.2 Emptying of tank. The delivery tank shall be emptied of all liquid.

4.3 Purging of vapor. As much as possible, the delivery tank shall be purged of all volatile vapors by any safe, acceptable method. One method is to carry a load of non-volatile liquid fuel, such as diesel or heating oil, immediately prior to the test, thus flushing out all the volatile gasoline vapors. A second method is to remove the volatile vapors by blowing ambient air into each tank compartment for at least 20 minutes. This second method is usually not as effective and often causes stabilization problems, requiring a much longer time for stabilization during the testing.

4.4 Temperature stabilization. As much as possible, the test shall be conducted under isothermal conditions. The temperature of the delivery tank should be allowed to equilibrate in the test environment. During the test, the tank should be protected from extreme environmental and temperature variability, such as direct sunlight.

5. *Test Procedure.*

5.1 Preparations.

5.1.1. Open and close each dome cover.

5.1.2 Connect static electrical ground connections to tank. Attach the liquid delivery and vapor return hoses, remove the liquid delivery elbows, and plug the liquid delivery fittings.

(Note.—The purpose of testing the liquid delivery hoses is to detect tears or holes that would allow liquid leakage during a delivery. Liquid delivery hoses are not considered to be possible sources of vapor leakage, and thus, do not have to be attached for a vapor leakage test. Instead, a liquid delivery hose

could be either visually inspected, or filled with water to detect any liquid leakage.)

5.1.3 Attach the test cap to the end of the vapor recovery hose.

5.1.4 Connect the pressure-vacuum supply hose and the pressure-vacuum relief valve to the shut-off valve. Attach a manometer to the pressure tap.

5.1.5 Connect compartments of the tank internally to each other if possible. If not possible, each compartment must be tested separately, as if it were an individual delivery tank.

5.2 Pressure test.

5.2.1 Connect the pressure source to the pressure-vacuum supply hose.

5.2.2 Open the shut-off valve in the vapor recovery hose cap. Applying air pressure slowly, pressurize the tank to P_i, the initial pressure specified in the regulation.

5.2.3 Close the shut-off valve and allow the pressure in the tank to stabilize, adjusting the pressure if necessary to maintain pressure of P_i. When the pressure stabilizes, record the time and initial pressure.

5.2.4 At the end of t minutes, record the time and final pressure.

5.2.5 Repeat steps 5.2.2 through 5.2.4 until the change in pressure for two consecutive runs agrees within ±12.5 mm H_2O. Calculate the arithmetic average of the two results.

5.2.6 Compare the average measured change in pressure to the allowable pressure change, Δp, as specified in the regulation. If the delivery tank does not satisfy the vapor tightness criterion specified in the regulation, repair the sources of leakage, and repeat the pressure test until the criterion is met.

5.2.7 Disconnect the pressure source from the pressure-vacuum supply hose, and slowly open the shut-off valve to bring the tank to atmospheric pressure.

5.3 Vacuum test.

5.3.1 Connect the vacuum source to the pressure-vacuum supply hose.

5.3.2 Open the shut-off valve in the vapor recovery hose cap. Slowly evacuate the tank to V_i, the initial vacuum specified in the regulation.

5.3.3 Close the shut-off valve and allow the pressure in the tank to stabilize, adjusting the pressure if necessary to maintain a vacuum of V_i. When the pressure stabilizes, record the time and initial vacuum.

5.3.4 At the end of t minutes, record the time and final vacuum.

5.3.5 Repeat steps 5.3.2 through 5.3.4 until the change in vacuum for two consecutive runs agrees within ◊12.5 mm H_2O. Calculate the arithmetic average of the two results.

5.3.6 Compare the average measured change in vacuum to the allowable vacuum change, Δp, as specified in the regulation. If the delivery tank does not satisfy the vapor tightness criterion specified in the regulation, repair the sources of leakage, and repeat the vacuum test until the criterion is met.

5.3.7 Disconnect the vacuum source from the pressure-vacuum supply hose, and slowly open the shut-off valve to bring the tank to atmospheric pressure.

5.4 Post-test clean-up. Disconnect all test equipment and return the delivery tank to its pretest condition.

6. *Alternative Procedures.*

6.1 The pumping of water into the bottom of a delivery tank is an acceptable alternative to the pressure source described above. Likewise, the draining of water out of the bottom of a delivery tank may be substituted for the vacuum source. Note that some of the specific step-by-step procedures in the method must be altered slightly to accommodate these different pressure and vacuum sources.

6.2 Techniques other than specified above may be used for purging and pressurizing a delivery tank, if prior approval is obtained from the Administrator. Such approval will be based upon demonstrated equivalency with the above method.

[FR Doc. 83-22280 Filed 8-17-83; 8:45 am]
BILLING CODE 6560-50-M

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40 CFR Part 60

[AD-FRL-2241-6a]

Addition of Reference Method 21 to Appendix A

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action establishes a new reference method to be added to Appendix A of 40 CFR Part 60, standards of performance for new stationary sources. Reference Method 21 will be used to determine volatile organic compound (VOC) leaks from process equipment such as valves, flanges and other connections, pump and compressor seals, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals. This reference method will be used in several air pollution regulations for the limitation of fugitive VOC emissions which are being developed for proposal and promulgation.

EFFECTIVE DATE: August 18, 1983.

ADDRESSES: *Docket.* A docket, number A-79-32, containing information considered by EPA in development of standards of performance for fugitive emission sources in the synthetic organic chemical manufacturing industry, and which also contains information considered in development of the promulgated reference method, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401, M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Winton Kelly, Emission Measurement Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5543.

SUPPLEMENTARY INFORMATION:

Summary of the Reference Method

Reference Method 21, "Determination of Volatile Organic Compound Leaks" is used to detect VOC leaks from individual sources of fugitive emissions. This procedure is used to identify and classify leaks only, and is not to be used as a direct measure of mass emission rates from individual sources. A portable instrument is used to measure the local organics concentration at the surface of a potential leak source. If a meter reading equal to or greater than a limit specified in an applicable regulation is obtained, a VOC emission (leak) exists. The procedure can also be used to confirm that "no detectable emissions" are present. If the measured difference between the local ambient concentration and the concentration present at the surface of the potential leak source is less than a concentration specified in an applicable regulation, then there are no detectable emissions.

Background

On January 5, 1981, as an appendix to the proposed standards of performance for fugitive emission sources in the synthetic organic chemical manufacturing industry, EPA proposed Reference Method 21. This method would normally be promulgated with those standards. However, the method is being promulgated earlier because several additional regulations are being developed for promulgation in the near future that specify that Reference Method 21 be used. This early promulgation will ensure that the reference procedure will be promulgated prior to being specified in promulgated standards of performance.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and, therefore, subject to the requirement of a regulatory impact analysis. This regulation is not major because it will not have an annual effect on the economy of $100 million or more; it will not result in a major increase in costs or prices; and there will be no significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of U.S.-based enterprise to compete with foreign-based enterprises in domestic or export markets.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the attached rule will not have a significant economic

impact on a substantial number of small entities.

Public Participation

During the development of the test method, trade and professional associations and individual companies supplied comments on the methods. After proposal on January 5, 1981, comments were received from various sources. A public hearing was held on March 3, 1981, to receive additional formal comments. The formal comment period was extended from April 6, 1981, to July 31, 1981.

Public Comments and Changes Made to the Proposed Reference Method

Numerous comments were received in response to proposal of the standards of performance for fugitive emissions from synthetic organic chemical industry. Most of the comments concerning the test method were specifically related to the selection of the definition of a leak, and not to the procedure alone. These comments have been carefully considered and, where determined to be appropriate, changes have been made in the proposed test method. A detailed discussion of the comments and full responses will be included in Docket No. A-79-32.

The following discussion summarizes the changes made to the reference method based on additional review and in response to public comment.

The promulgated reference method has been reorganized to improve the clarity of the description of the procedures. A "Definitions" section has been added to place all the definitions in one section.

A change in the requirements for instrument performance evaluation was also made to improve the quality control of the procedure. Instead of requiring a calibration precision test consisting of nine repetitions at 6-month intervals, the new requirements specify a test consisting of three repetitions at 3-month intervals. This change will provide a quality control result every quarter and will require less effort.

The definition of "no detectable emissions" has been changed to be consistent with the instrument specification of scale readability. The proposed procedure defined "no detectable emissions" as 2 percent of the leak definition concentration, with a minimum scale readability of 5 percent of the leak definition. The definition of "no detectable emissions" has been changed to correspond to the minimum readability specification and will be specified in applicable regulations.

Several commenters noted that the instruments used during screening studies responded differently for different chemicals. One commenter stated that the actual response factor was poorly related to the theoretical response factor and cited inconsistent responses for nonane and decane, as well as no response for some chemicals, to support his claims. Another commenter suggested that the leak concentration for the standards should vary according to the process unit since a wide variability (0 to 571) in response factors has been determined for the industry. And, another commenter stated that aromatic compounds such as benzene, toluene, and xylene demonstrate a nonlinear response close to 10,000 ppmv. In response to these comments, Reference Method 21 gives specifications for the instrument to be used in monitoring fugitive VOC emission sources. The technique is intended to classify leaks only, not to provide a rigorous analytical concentration or mass emission rate of VOC. A specific statement has been added to Method 21 to clarify the intention to classify leaks only. The variation in response factor due to compound or instrument is not expected to affect significantly the number of leaks determined through screening because screening values are usually much greater than the leak definition for leaks and much less than the leak definition for nonleaks. Two industry commenters concur with EPA in this position. However, to remove some of the wide variability, a definition, specification, and test procedure for response factors have been added to Method 21. This specification will assure that the analyzer used will respond to the compounds to be measured.

Another commenter suggested that the gas specification section be amended to include a turnover of calibration gas standards every 3 months since calibration gases can deteriorate significantly over time. A provision has been added to the promulgated Reference Method 21 to require a shelf-life specification on calibration gases and procedures to follow to ensure that calibration gas concentrations are accurate.

Two comments concerned the instrumentation requirements of Reference Method 21. The commenter stated that only two instruments on the market today could be considered, and neither one would meet the specifications of the reference method entirely: the first instrument fails the calibration accuracy, and the section instrument does not meet the response time requirement. In response, although there are only two instruments which have been used to any great extent, the technical literature and product information suggest that there are others which could be used for detecting leaks. The specifications included in the proposed reference method are achievable based on performance during EPA studies.

One comment letter expressed concern that no provision was made for the use of new instruments or calibration procedures which would provide equivalent or more accurate results. They asked that equivalency provisions be added for test methods and procedures. In response, Reference Method 21 gives specifications for the monitoring instrument that are general enough so as not to preclude new analytical developments. In addition, the General Provisions (40 CFR Part 60, Subpart A) allow for equivalent methods and procedures to be used for performance testing and monitoring when the results of the equivalent method have been demonstrated to be at least as accurate as results obtained by the required methods.

One commenter suggested that use of a windscreen upwind of the component being screened would prevent meteorological effects on the instrument readings. During EPA studies, the selection of a measurement location at the surface of the source was made to minimize meteorological effects. During the data collection efforts, no further provisions were found necessary to obtain repeatable screening values. Therefore, all of the field data were collected without a windscreen. In view of these facts, it seems unnecessary to require that a windscreen be used.

An alternative screening procedure has been added for those sources that can be tested with a soap solution. These sources are restricted to those with non-moving seals, moderate surface temperatures, without large openings to atmosphere, and without evidence of liquid leakage. The soap solution is sprayed on all applicable sources and the potential leak sites are observed to determine if bubbles are formed. If no bubbles are formed, then no detectable emissions or leaks exist. If any bubbles are formed, then the instrument measurement techniques must be used to determine if a leak exists, or if no detectable emissions exist, as applicable.

The alternative soap solution procedure does not apply to pump seals, sources with surface temperatures greater than the boiling point or less than the freezing point of the soap solution, sources such as open-ended lines or valves, pressure relief value

horns, vents with large openings to atmosphere, and any source where liquid leakage is present. The instrument technique in the method must be used for these sources.

The alternative of establishing a soap scoring leak definition equivalent to a concentration-based leak definition is not included in the method and is not recommended for inclusion in an applicable regulation because of the difficulty of calibrating and normalizing a scoring technique based on bubble formation rates. A scoring technique would be based on estimated ranges of volumetric leak rates. These estimates depend on the bubble size and formation rate, which are subjective judgments of an observer. These subjective judgments could only be calibrated or normalized by requiring that the observers correctly identify and score a standard series of test bubbles. It has been reported that trained observers can correctly and repeatably classify ranges of volumetric leak rates. However, because soap scoring requires subjective observations and since an objective concentration measurement procedure is available, a soap scoring equivalent leak definition is not recommended for the applicable regulation. The alternate procedure that has been included will allow more rapid identification of potential leaks for more rigorous instrumental concentration measurement.

Miscellaneous

This final rulemaking is issued under the authority of Sections 111, 114, and 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7414, and 7691(a)].

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc, Tires.

Dated: August 4, 1983.

William D. Ruckelshaus,

Administrator.

Appendix A of 40 CFR Part 60 is amended by adding Reference Method 21 as follows:

Appendix A—Reference Methods

* * * * *

Method 21. Determination of Volatile Organic Compounds Leaks

1. Applicability and Principle.

1.1 Applicability. This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rates from individual sources.

2. Definitions.

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example: If a leak definition concentration is 10,000 ppmv as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppmv, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is not present. Since background VOC concentrations may exist, and to account for instrument drift and imperfect reproducibility, a difference between the source surface concentration and the local ambient concentration is determined. A difference based on meter readings of less than a concentration corresponding to the minimum readability specification indicates that a VOC emission (leak) is not present. (For example, if the leak definition in a regulation is 10,000 ppmv, then the allowable increase in surface concentration versus local ambient concentration would be 500 ppmv based on the instrument meter readings.)

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the application regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 Response Time. The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. Apparatus.

3.1 Monitoring Instrument.

3.1.1 Specifications.

a. The VOC instrument detector shall respond to the compounds being processed. Detector types which may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

b. The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

c. The scale of the instrument meter shall be readable to 5 percent of the specified leak definition concentration.

d. The instrument shall be equipped with a pump so that a continuous sample is provided to the detector. The nominal sample flow rate shall be ⅛ to 3 liters per minute.

e. The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the applicable U.S.A. standards (e.g., National Electrical Code by the National Fire Prevention Association).

3.1.2 Performance Criteria.

a. The instrument response factors for the individual compounds to be measured must be less than 10.

b. The instrument response time must be equal to or less than 30 seconds. The response time must be determined for the instrument configuration to be used during testing.

c. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

d. The evaluation procedure for each parameter is given in Section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated as subsequent intervals.

b. The calibration precision test must be completed prior to placing the analyzer into service, and at subsequent 3-month intervals or at the next use whichever is later.

c. The response time test is required prior to placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required prior to further use.

3.2 Calibration Gases. The monitoring instrument is calibrated in terms of parts per million by volume (ppmv) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppmv VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration as mixture are used, they must be analyzed and certified by the manufacturer to be within ±2 percent

accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternately, calibration gases may be prepared by the user according to any accepted gaseous standards preparation procedure that will yield a mixture accurate to within ±2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. Procedures.

4.1 Pretest Preparations. Perform the instrument evaluation procedures given in Section 4.4 if the evaluation requirements of Section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

Note.—If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

4.3 Individual Source Surveys.

4.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves—The most common source of leaks from valves is at the seal between the stem and housing. Place the probe at the interface where the stem exists the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where leak could occur.

b. Flanges and Other Connections—For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

c. Pumps and Compressors—Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

d. Pressure Relief Devices—The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

e. Process Drains—For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

f. Open-Ended Lines or Valves—Place the probe inlet at approximately the center of the opening to the atmosphere.

g. Seal System Degassing Vents and Accumulator Vents—Place the probe inlet at approximately the center of the opening to the atmosphere.

h. Access Door Seals—Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

4.3.2 Type II—"No Detectable Emission". Determine the local ambient concentration around the source by moving the probe inlet randomly upwind and downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration described in 4.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation.

For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:

(a) Pump or Compressor Seals—If applicable, determine the type of shaft seal. Preform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described above.

(b) Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices—If applicable, observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur prior to the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere prior to the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in this paragraph shall be used to determine if detectable emissions exist.

4.3.3 Alternative Screening Procedure. A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument techniques of 4.3.1 or 4.3.2.

Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or a squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detactable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of 4.3.1 or 4.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

4.4 Instrument Evaluation Procedures. At the beginning of the instrument performance evaluation test, assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

4.4.1 Response Factor. Calibrate the instrument with the reference compound as specified in the applicable regulation. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration of approximately 80 percent of the applicable leak definition unless limited by volatility or explosivity. In these cases, prepare a standard at 90 percent of the saturation concentration, or 70 percent of the lower explosive limit, respectively. Introduce this mixture to the analyzer and record the observed meter reading. Introduce zero air until a stable reading is obtained. Make a total of three measurements by alternating between the known mixture and zero air. Calculate the response factor for each repetition and the average response factor.

Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in Section 5.

4.4.2 Calibration Precision. Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and mutiply by 100 to express the resulting calibration precision as a percentage.

4.4.3 Response Time. Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. Measure the time from switching to when 90 percent of the final stable reading is attained. Perform this test sequence three times and record the results. Calculate the average response time.

5. Bibliography.

5.1 DuBose, D.A., and G.E. Harris. Response Factors of VOC Analyzers at a Meter Reading of 10.000 ppmv for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA 600/2–81–051. September 1981.

5.2 Brown, G.E., et al. Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA 600/2–81–022. May 1981.

5.3 DuBose, D.A., et al. Response of Portable VOC Analyzers to Chemical Mixtures. U.S. Environmental Protection Agency, Research Triangle Park, N.C. Publication No. EPA 600/2–81–110. September 1981.

[FR Doc. 83–22499 Filed 8–17–83; 8:45 am]

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federal register

Thursday
August 25, 1983

Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Beverage Can Surface Coating Industry

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2097-2]

Standards of Performance for New Stationary Sources; Beverage Can Surface Coating Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for the beverage can surface coating industry were proposed in the Federal Register on November 26, 1980 (45 FR 78960). This action promulgates standards of performance for the beverage can surface coating industry. These standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination that beverage can surface coating operations cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed beverage can surface coating operations to control emissions to levels achievable through the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: August 25, 1983.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Background Information Document.* The Background Information Document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Beverage Can Surface Coating Industry—Background Information for Promulgated Standards "EPA-450/3-80-036b. The BID contains (1) a summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final Environmental Impact Statement, which summarizes the impacts of the standards.

Docket. A docket, number A-80-4, containing information considered by EPA in development of the promulgated standards is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

SUPPLEMENTARY INFORMATION:

The Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> • • • Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, [and] any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this criterion will be referred to as "best demonstrated technology" or "BDT."

The promulgated standards apply to all new, modified, and reconstructed two-piece beverage can surface coating operations for which construction, modification, or reconstruction commenced after November 26, 1980. The standards define a two-piece beverage can as any two-piece steel or aluminum container in which soft drinks or beer (including malt liquors) are packaged. Containers in which fruit or vegetable juices are packaged are excluded. Existing facilities would not be subject to the standards unless they undergo a modification or reconstruction as defined in 40 CFR 60.14 or 60.15. Emissions of volatile organic compounds (VOC) from affected facilities at two-piece can plants are limited as follows: 0.29 kg VOC/litre of coating solids from each exterior base coating operation except clear base coating, 0.46 kg VOC/litre of coating solids from each overvarnish coating operation and each clear base coating operation, and 0.89 kg VOC/litre of coating solids from each inside spray coating operation. Each affected facility consists of a coating application station, a flashoff area and a cure oven.

BDT for the surface coating operations covered by the promulgated standards is the use of best available waterborne coatings. However, the standards would permit the use of any system of continuous emission reduction that allows the facility to comply with these emission limits. For example, the standards could also be achieved through the use of solvent-borne coatings in combination with an emission control system. The compliance procedures outlined in the promulgated regulations are designed to show equivalence between the use of waterborne coatings and the use of solvent-borne coatings and an emission control system.

The owner or operator is required to conduct a performance test each calendar month for each affected facility and record the results. The calculation of the volume-weighted average mass of VOC per volume of coating solids during each calendar month constitutes a performance test. The owner or operator is required to identify and report, semiannually, each instance that the calculated volume-averaged mass of VOC per volume of coating exceeds the emission limitations. When Method 24 data are used to determine VOC content of waterborne coatings for compliance determinations, precision factors shall be used as described in Section 4.4 of Method 24.

Where compliance is achieved through the use of waterborne coatings, compliance with the standards is determined by comparing the calculated volume-weighted average mass of VOC per volume of coating solids with the applicable emission limitation in the promulgated standards. Volume and VOC content of each coating used at the affected facility for the calendar month are required for this determination. If each coating used at an affected facility during a calendar month has a VOC content equal to or less than the emission limitations prescribed in the standards, and no VOC solvents are added during distribution and application of the coatings, the affected facility is in compliance and calculation of the volume-weighted average VOC content is not required.

Where compliance is achieved through the use of solvent-borne coatings and an emission control system, the volume-weighted average VOC content is calculated as for waterborne coatings. The calculated VOC content is reduced by the most recently determined overall reduction efficiency of the capture and emission control system. The promulgated regulations prescribe procedures for determining overall reduction efficiency

for emission control systems using incineration or solvent recovery.

The owner or operator of an affected facility who uses incineration to comply with the standards must maintain records of incinerator performance and identify and report, semiannually, all 3-hour periods during which the average temperature of the device, during processing of cans, is significantly lower than the average temperature observed during the most recent performance test at which destruction efficiency was determined.

Surface coating operations in the manufacture of can ends and three-piece steel cans are excluded from the standards because industry projections show an excess capacity for these operations, indicating that no facilities will become subject to the standards through 1985. Application of ink/lithography is excluded because emissions from this operation are insignificant. Application of end-sealing compound to ends for two-piece beverage cans is excluded because BDT is the same as that in common use today.

Summary of Environmental, Energy, and Economic Impacts

The promulgated standards would reduce VOC emissions by approximately 32 percent from the baseline emission level. The standards of performance would result in a 47-percent reduction in VOC emissions from the exterior base coat operation, a 15-percent emission reduction from the overvarnish coating operation, and a 28-percent emission reduction from the inside spray coating operation. Annual nationwide VOC emissions would be reduced by about 2,900 Mg (3,190 tons) by 1986.

Little or no incremental water pollution impact from new, modified, or reconstructed beverage can surface coating operations would result from implementation of the standards.

The promulgated standards would also have little or no incremental solid waste impact.

Based on industry growth projections, application of the standards would result in a net energy reduction of about 19,000 GJ in 1985, or a reduction of 1 percent from the baseline. The net energy reduction results from the use of less coating per can because of higher solids content of the waterborne coatings upon which the standards are based.

The promulgated standards are expected to have little economic impact on the beverage can industry. At least one control option, the cost of which is equal to or less than the cost of compliance with the baseline level of control, is available for each affected facility.

The environmental, energy, and economic impacts are discussed in greater detail in the Background Information Document (BID) for the proposed standards, "Beverage Can Surface Coating Industry—Background Information for Proposed Standards," EPA-450/3-80-036a.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, an evaluation and verification of applicable emission tests methods, and identification of specific emission limits achievable with alternative technologies. The costs are provided for an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact of controls on an industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register (45 FR 30686; May 9, 1980) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the beverage can surface coating industry standards recommended for proposal. This meeting, held on June 4, 1980, was open to the public, and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the Federal Register on November 26, 1980 (45 FR 78980). The preamble to the proposed standards discussed the availability of the Background Information Document, "Beverage Can Surface Coating Industry—Background Information for Proposed Standards," EPA-450/3-80-036a, which described in detail the regulatory alternatives considered in the development of the standards and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on January 6, 1981, at Research Triangle Park, North Carolina. The hearing was open to the public, and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from November 26, 1980 to February 5, 1981. At industry's request, the public comment period was reopened from February 27 through March 30, 1981.

Eighteen comment letters were received and four interested parties testified at the public hearing concerning issues relative to the proposed standards of performance for the beverage can surface coating industry. The comments have been carefully considered; and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from the beverage can surface coating industry, coating manufacturers, Federal agencies, State pollution control agencies, and a trade association. A detailed discussion of these comments and responses can be found in the BID, which is referred to in the ADDRESSES section of this preamble. The comments and analyses expressed in the responses serve as the basis for the revisions that have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble. The comments have been divided into the following areas: General, emission control technology, modification and reconstruction, economic impact, environmental impact, energy impact, legal considerations, test methods and monitoring, reporting and recordkeeping, and miscellaneous.

Major changes in the promulgated standards from the proposed standards are (1) exclusion of three-piece cans from the standards, (2) exclusion of end sheet coating from the standards, (3) adding the requirement that precision factors, as described in Section 4.4 of Method 24, be used when Method 24 data are employed to determine VOC content of waterborne coatings for compliance determinations, and (4) changing the requirement for immediate reporting of exceedances to semiannual reporting.

General

Six commenters stated that three-piece beverage cans were being phased out, with an estimated 1985 production of between 0.5 and 1.5 billion cans, and should be excluded from the standards. As a result of these comments, EPA analyzed previous projections and determined that estimated demands for three-piece can capacity in 1985 would be about 50 percent of the estimated available capacity. Consequently, three-piece cans are excluded from the promulgated standards. The decrease in three-piece can production would free more coating capacity than is needed for the coating of steel and aluminum sheets for the manufacture of beverage can ends. This capacity can be used for coating aluminum sheets for ends with little or no change. Thus, no end sheet coating capacity would become subject to NSPS through 1985. Consequently, surface coating of end stock is also excluded from the standards.

Several comments were received stating that the proposed standards were not based on the best demonstrated systems of continuous emission reduction. Three commenters stated that the use of waterborne coatings has not been demonstrated as being commercially available. One commenter doubted that solvent-borne coatings and incineration could be used in the event waterborne coatings were impracticable. One commenter stated that promulgation of the proposed standards would force the industry to turn to one supplier for inside spray materials.

As a result of these comments, EPA significantly expanded the data base upon which the promulgated standards are based through telephone and written communications with coaters and coating suppliers. The expanded data base substantiated EPA's previous determination that the use of waterborne coatings is BDT and that coatings meeting the promulgated emission limits are available from more than one supplier. Summary of the data base by coating operations follow:

Two-piece Can Exterior Base Coat

Five canmakers, four merchant and one captive, reported using coatings with VOC contents equal to or less than that specified in the standards. Three of these canmakers identified four coatings from one supplier as being used, two reporting the use of complying coatings for all base coat requirements. Of the remaining canmakers, one did not identify the coating being used, and the other claimed confidentiality for the coating being used. One additional coating from a second supplier has been qualified for use on one merchant coater's new and existing can lines. In discussions with canmakers during the collection of the data, no specific cases were identified in which waterborne coatings could not be used for the application of exterior base coat to two-piece beverage cans.

Two-Piece Can Overvarnish/Clear Base Coat

Four canmakers, three merchant and one captive, reported using coatings with VOC contents equal to or less than that specified in the standards. Two of these canmakers identified four coatings from two suppliers as being used, one reporting the use of complying coatings for all overvarnish requirements. Of the remaining canmakers, one did not identify the coating being used, and the other claimed confidentiality for five coatings used. All of the captive canmakers' requirements are being satisfied by waterborne coatings meeting the NSPS emission limitations. Five additional coatings meeting the NSPS emission limitations are available from three suppliers. Future testing is planned for some of these coatings. In discussions with canmakers during the collection of the data, no specific cases were identified in which waterborne coatings could not be used for the application of overvarnish or clear base coat to two-piece beverage cans.

Two-Piece Can Inside Spray

Seven canmakers, five merchant and two captive, reported using coatings with VOC contents equal to or less than that specified in the standards. Five of these canmakers identified four coatings from three suppliers as being used, two canmakers reporting the use of complying coatings for all inside spray requirements. Of the remaining two, one did not identify the coating being used, and the other claimed confidentiality for the coatings being used. During the collection of the data, two specific cases were identified in which satisfactory waterborne coatings were not available. One canmaker reported that at two plants making cans for export, excessive pinholing occurred because the extreme abuse the cans received in shipping and handling caused separation of the coating. In subsequent discussions, the canmaker reported that the problems had been resolved and that waterborne coatings meeting the NSPS emission limitations are now being used for all inside spray operations at one plant, and that a program is underway at the second plant to develop a suitable waterborne inside spray system. This plant is currently incinerating VOC emissions from inside spray operations to meet local regulations. In the second case, difficulty was being experienced in applying waterborne inside spray to steel cans. In this case, solvent-borne coatings are required to make satisfactory cans and incineration is employed to satisfy the local emission limitations. The same procedures can be used to satisfy NSPS emission limitations. The necessary capture and destruction of VOC can be attained by enclosing the flashoff areas and incinerating flashoff and cure oven exhausts.

One public hearing participant took exception to statements made in the beverage can factsheet that probably 4 new three-piece can plants and 10 to 20 new two-piece can plants were to be built between 1980 and 1985. The participant felt that this was not consistent with data that industry presented at the NAPCTAC meeting in June 1980 that indicated a dramatic reduction in three-piece can production and a leveling off of demand for two-piece cans.

The beverage can factsheet, a summary of the proposal BID and regulation published at the time of proposal, states that "EPA estimates 10 to 20 two-piece beverage can plants and 4 three-piece beverage can plants will be affected by the proposed NSPS, the latter subject under the modification or reconstruction provisions." These plants are model plants and are the number that were considered subject to NSPS for the purposes of the economic analyses. It should be noted that the statement concerning three-piece can plants specifically excludes new facilities and indicates that facilities in place in 1979 would become subject to the modification or reconstruction provisions. The estimates of the number of model plants that would be subject to NSPS were based on industry estimates of the projected market share of two-piece and three-piece beverage cans that were later changed by data provided by the industry during the public comment period. As previously mentioned, EPA analyzed the new industry data and developed revised projections that show that no three-piece can plants would be subject to the NSPS through 1985. Insofar as two-piece can plants are concerned, based on the revised projection it is estimated that between 7 and 15 two-piece model plant equivalents would be subject to NSPS in 1985, half under the reconstruction or modification provisions. These estimates are based on an average of 5 percent of existing capacity becoming subject to NSPS under the modification

and reconstruction provisions each year through 1985. These estimates are consistent with industry projections that show an increase in two-piece can shipments from 49.6 billion cans in 1980 to 61.9 billion cans in 1985.

Two participants at the public hearing were concerned that if NSPS emission limitations were promulgated, major reformulation of coatings developed to meet RACT would be required. This redirection of coating suppliers' efforts would be at the expense of developing coatings to satisfy RACT. Such an approach could result in achieving neither RACT nor NSPS.

EPA agrees that major reformulation may be required for some low-solvent coatings. However, given the coating data obtained from canmakers and coating suppliers, this does not appear to be a problem. A majority of the coatings developed to satisfy RACT requirements would also satisfy NSPS requirements. Four coatings each for exterior base coat, overvarnish, and inside spray, developed in response to RACT requirements but also meeting the NSPS emission limitations, are being widely used by the industry.

Two comments were received questioning the change in format of the standards from kilograms of VOC per litre of coating less water, as used in RACT, to kilograms of VOC per litre of solids. EPA has determined that the format of the promulgated standards is appropriate. Compliance with the promulgated standards is determined by comparing a volume-weighted average of the VOC content of all coatings and diluent solvents applied at an affected facility during each calendar month with the emission limitations of the promulgated standards. This requires conversion of VOC content of each coating used to mass of VOC per volume of coating solids. This procedure must be used in averaging VOC content of coatings for RACT determination as well. Consequently no change is made to the format of the standards.

One commenter questioned the need for an NSPS that requires industry to do what is already being done. New installations in nonattainment areas would be required to use lowest achievable emission rate (LAER), which in this case would be "achieved in practice," that would be the same as the proposed NSPS. Installations in attainment areas, if any, would of course be required to apply best available control technology (BACT), which would be the coatings now in use and the same as the proposed NSPS.

In enacting Section 111, Congress intended to insure that every new, modified, or reconstructed facility, wherever located, control emissions to at least a nationally uniform emission ceiling. Congress recognized that in individual cases greater emissions reduction could be achieved than that achievable through application of BDT. For these individual cases, the Act may require application of more stringent requirements. Even though, as the commenter suggests, BACT or LAER requirements applicable in such individual cases may eventually spur development of broadly demonstrated coatings similar to or better than NSPS-level coatings, Section 111 still requires the Agency to set minimum nationally applicable standards that will insure control of emissions at new sources to at least the level achievable through use of BDT.

One commenter stated that the proposed standards do not require the "best demonstrated system of continuous emission reduction * * * *" and that by regulating the VOC content of coatings for new sources without regard to quantity of coating supplied, the Agency is encouraging the construction of new facilities with greater emissions than identical existing CTG facilities. The commenter further stated that the quantity of coating needed by the various canmakers to produce an acceptable can is a much more significant factor in emission reduction technology than is the VOC content of the waterborne coatings used, and that manufacturing materials that inherently require less applied coating than other materials represents a better system of emission reduction. The commenter submitted that this is an obvious conclusion drawn from the draft EIS and from information contained in Docket A-80-4. As a result of ignoring this fact, the Agency has prepared a standard that cannot possibly be construed as meeting the intent of Section 111 of the Clean Air Act.

In EPA's judgment, the promulgated standards are based on BDT. Formatting the standards in terms of mass of VOC per unit of production, e.g., 1,000 cans, was considered in the development of the standards. This approach was discarded because of inflexibility in accommodating the range of coating thicknesses used by the industry to meet the requirements of the many types of beverage cans produced by the industry, especially at merchant can plants. Such an approach also raised problems in setting numerical limits for the standards. If an industry-average coating thickness is used as the basis, coaters using an above-average coating thickness would be penalized. The Agency considers the cost of specifying maximum coating thickness for each usage unreasonable and exorbitant. Consequently, this format was rejected in favor of the mass of VOC per volume of coating solids format.

Emission Control Technology

A comment was made that the proposed emission limitations were so stringent that coating suppliers would not have any latitude to vary formulations as required to meet the wide range of equipment used and the environmental conditions encountered in beverage can surface coating operations.

EPA has determined from coating data obtained from canmakers that coating suppliers are providing coatings meeting the promulgated emissions limitations for a wide range of equipment and environmental conditions. Only two specific cases were identified involving two-piece can inside spray operations in which satisfactory waterborne coatings were not available. In these cases operational and environmental requirements were being satisfied through the use of solvent-borne coatings and incineration. Furthermore, the monthly averaging provisions of the standards for each affected facility would permit the use of some coatings not meeting the standards, provided other coatings with lower VOC content were used to bring the monthly volume-weighted average to the promulgated emission limitations.

One commenter stated that under NSPS, existing coating systems that have not yet been able to meet RACT values must meet even more stringent emission standards. Essentially only incineration, a counterproductive energy-consuming system, can be used.

Existing coating systems are not required to meet the promulgated standards unless the facility undergoes modification or reconstruction as defined in 40 CFR Part 60. Under such circumstances, in EPA's judgement, there are sufficient coatings commercially available for a wide variety of coating systems to meet the standards. Based on the economic analysis in Chapter 8, proposal BID, incineration is considered to be a reasonable and affordable option.

Several commenters expressed concern that if NSPS materials for two-piece can inside spray are not available, afterburners will have to be used. This could very well call for an overall control efficiency of 60 percent, requiring approximately 90 percent capture efficiency, which is not attainable.

In response to this and other comments, EPA expanded the coating

data base with information from canmakers and coating suppliers that indicates the availability of a variety of waterborne coatings for inside spray. The VOC content of waterborne coatings reported as being used by both merchant and captive canmakers ranges from 0.46 kg VOC/litre of solids to 0.90 kg VOC/litre solids compared with the promulgated emission limitation of 0.89 kg VOC/litre of solids. The promulgated regulations permit monthly averaging, which should facilitate satisfying the requirements.

During the collection of data only two cases were identified in which satisfactory waterborne coatings were not available. In these cases, solvent-borne coatings and incineration provided the emission reduction required by the applicable SIP.

A typical higher solids solvent-borne inside spray coating in general use contains 3.01 kg VOC/litre of coating solids (Table 4–2, proposal BID). An overall control efficiency of 70 percent is required to reduce the VOC emissions from the use of this typical inside spray coating to the emission level prescribed in the promulgated standards. A test at a two-piece can plant, using Method 25 procedures, showed a 78-percent capture efficiency of VOC emissions from coater, flashoff area, and cure oven on an inside spray line. This capture efficiency is considered to be conservative because the cure oven quench exhaust was not quantified in the test. Combining this capture efficiency with a nominal 90-percent incinerator destruction efficiency results in an overall control system efficiency of 70 percent. It is the Agency's engineering judgment that in instances in which the use of waterborne coatings may not be applicable, the necessary capture and control (destruction or recovery) are attainable at a reasonable and affordable cost (Chapter 8, proposal BID).

Several commenters stated that because of (1) difficulties being experienced in implementing the RACT program, (2) the limited capabilities of users to qualify new coatings, (3) the problems involved in qualifying NSPS materials on existing lines prior to the construction of new facilities, and (4) small incremental emission reduction from NSPS compared to that resulting from the trend away from three-piece cans to two-piece cans, RACT values should form the basis for NSPS.

EPA has determined that the promulgated emission limitations for two-piece cans represent BDT. The problems of implementing RACT and the problem generated by the limited capabilities of users to qualify new coatings appear to be overstated in light of the coating data obtained from canmakers and coating suppliers. Numerous coatings with VOC content equal to or less than RACT are being used on existing two-piece can lines. In addition to meeting RACT, many of these coatings also satisfy the NSPS requirements. The problems of qualifying NSPS materials on existing lines prior to the construction of new facilities would not be resolved by using RACT as the basis of the NSPS. One practice prevalent throughout the industry is that coatings must be qualified on each line regardless of their use in other plants operated by the same canmaker. EPA agrees that there has been a significant reduction in VOC emissions as a result of RACT and the trend away from three-piece cans to two-piece cans. However, EPA is mandated under Section 111 of the Clean Air Act to base NSPS on BDT, which for this industry is the use of coatings with lower organic solvent content than RACT coatings.

One commenter stated that EPA, in proposing NSPS, has tried to design can lines and specific materials.

EPA formulated model plants in order to perform the environmental and economic analyses required in NSPS development. These are not intended to represent what an actual plant should look like, but rather present a range of capacities as the basis for subsequent analyses. The model plants are based on coatings currently in use on sufficient lines to warrant the determination of the availability of NSPS-compliance coatings. EPA's specification of BDT is not in any way a requirement that facilities use a specific technology.

Two commenters challenged the implied assumption in the BID that the industry is using coatings that are RACT as defined in CTG–II.

The assumption that industry is currently using RACT coating was not made in the development of the NSPS. Rather, the assumption was made that SIP emission limitations would be based on RACT and that RACT should form the baseline case against which the environmental and energy analyses could be made.

EPA recognizes that on some can lines, coatings with VOC content lower than RACT are being used. These coatings serve as the bases for the promulgated emission limitations. On other lines RACT coatings are being used, and on the remaining lines coatings with VOC content higher than RACT are in use. In the development of a baseline for the environmental and energy analyses, EPA made the assumption that in the absence of NSPS, the industrywide average VOC content would be equal to RACT.

One commenter stated that the distinction should be made in the draft EIS (p. 3–10) between steel and aluminum with regard to exterior base coat for two-piece cans.

EPA made no distinction between steel and aluminum two-piece cans in the development of model plants. While it is recognized that different coatings thicknesses are required, the additional effort is not justified by the marginal improvement in accuracy that would result in estimating emissions and energy requirements in the subsequent analyses.

One commenter took exception to EPA's statement in 45 FR 78982 that "transfer efficiencies of 90 percent with inside spray operations are consistently achieved." Exactly what EPA's use of 10-percent VOC assessment in this instance means was unclear. It was requested that EPA consider allowing a facility that demonstrates a consistent transfer efficiency (for inside coating operations) of greater than 90 percent to credit that percentage above 90 percent against other coating operations that may exceed the compliance limits.

Because of the absence of standardized procedures for determining transfer efficiencies, the complicated calculations for estimating transfer efficiencies, and the high transfer efficiencies consistently achieved for inside spray operations (over 90 percent), EPA determined that introducing a transfer efficiency into the equations prescribed for determining compliance would unnecessarily complicate the compliance procedures. Because of the high transfer efficiencies (90 percent or higher) that are consistently achieved, inclusion of such a term in the compliance equation would be equivalent to introducing essentially the same term on both sides of the equation. Consequently, the promulgated standards are based on an assumed 100-percent transfer efficiency. It should be noted that a 90-percent transfer efficiency was used in the environmental and energy analyses for inside spray operations.

Two commenters questioned the use of an assumed VOC density of 0.85 kg/litre in converting RACT numbers to kilograms of VOC per litre of solids. One commenter claimed that it is dangerous to propose new standards on assumptions rather than hard data. For example, an error of 5 percent in VOC density would result in a change of 37 percent in the calculated kilograms of VOC per litre of solids. Furthermore, no can manufacturer or coating supplier

has been able to duplicate the data in the BID.

EPA recognizes that the conversion of VOC content from RACT terms is sensitive to the density of the VOC solvent. The selected density of 0.85 kg/litre is below that of the VOC normally used in waterborne coatings. Use of this density results in a higher VOC content per volume of solids than if the actual VOC density of the coating upon which the promulgated emission limitations are based were used. Inasmuch as this favors the coater, EPA considers this approach appropriate. The 37-percent error in calculated kilogram of VOC per litre of solids from a 5-percent error in density appears to be overstated. EPA calculations on the impact of a 5-percent error in density indicate, as shown below, that even if the assumed density of 0.85 kg/litre were inaccurate by 5 percent, the resulting effect on conversion from RACT to NSPS terms would not be significant.

Density	Calculated VOC content (kg/litre solids)	Percent change
VOC content kg/litre of coating less water = 0.060		
0.85 × 0.95	1.213	0.2
0.85	1.214	0
0.85 × 1.05	1.137	6.3
VOC content kg/litre of coating less water = 0.15		
0.85 × 0.95	0.184	1.1
0.85	0.182	0
0.85 × 1.05	0.180	1.1

The following equation was used in converting the RACT format to MSPS.

Kilograms of VOC per litre of solids = kilograms of VOC per litre of coating less water/1 (litre of coating) − kilograms of VOC per litre of coating less water/density of VOC.

Modification and Reconstruction

One commenter felt that the replacement of a coater or oven should not be classified as reconstruction because it is replacement in kind due to wear not to increased material usage, and that replacement should not be subject to NSPS.

In promulgating 40 CFR 60.15, EPA intended to subject to NSPS existing sources that have undergone such extensive component replacement that they have become essentially new sources. Application of BDT to facilities with largely new components furthers the intent of Congress that emissions be minimized through application of BDT with the turnover in the nation's industrial component base. This purpose is advanced through coverage of facilities that undergo substantial component replacement, whether the replacement is due to wear or increased material usage, and whether or not an emissions increase results from the replacement.

Under § 60.15, the replacement of a piece of equipment does not in itself subject an existing facility to NSPS. However, when the cost of components over time exceeds 50 percent of the cost of a comparable new facility and it is technologically and economically feasible for the facility to comply, NSPS would apply. In making decisions that involve the expenditure of funds that would trigger the reconstruction provisions, industry also should consider the cost of any control system that may be necessary to meet the NSPS requirements.

Economic Impact

Three commenters questioned EPA's conclusion that the proposed standards would have little economic impact on the beverage can industry. EPA would be imposing VOC emission limits below the (current) lowest achievable levels of several can coating manufacturers. If those manufacturers could not achieve the new levels, the November 28 proposals would be regulating them out out of business at the outset. This in turn would reduce or restrict competition within the coating supply industry, which would cause substantial economic hardship on can manufacturers. One commenter stated that industry's comments on this matter were ignored.

Because EPA's analyses of industry projections showed that no end or three-piece can capacity would be subject to the standards in 1985, only two-piece cans are covered by the promulgated standards. Therefore, response will be limited to two-piece beverage cans. The promulgated standards will not apply to existing facilities except when they become subject to the modification or reconstruction provisions of 40 CFR Part 60. Industry's recommendations concerning the adoption of emission limits lower than RACT were not ignored. For example, as a result of industry comments at the NAPCTAC meeting, application of end-sealing compound was excluded from the proposed standards. Industry recommendations were considered in the development of the promulgated standards, but in the light of other economic and coating availability data, a determination was made that the promulgation of NSPS for the beverage can surface coating industry would not result in exorbitant or unreasonable economic impacts.

As discussed in the General Comments section above, waterborne coatings that can meet the promulgated standards are available and in use in a sufficient number of cases to conclude that the technology is available for all uses except for inside spray for steel cans. Two existing plants have not been able to find a waterborne coating that performs properly for their particular applications and are using solvent-borne inside sprays with incineration to meet State and local emission standards. EPA's analysis indicates that there are no economic impacts to the industry if waterborne coatings are used. Waterborne coatings which comply with the standard are comparable in cost with waterborne coatings used to meet State and local regulations based on RACT; and both are less costly than the use of solvent-borne coatings with add-on controls. As noted above, two existing plants are currently meeting State and local standards by using solvent-borne coatings with incineration. These same controls could be used at new plants and, while additional costs may be required for fugitive capture to meet the NSPS and for a slightly larger incinerator, these represeent a small increment of the existing capture and incineration costs and would not affect plant viability or competition.

Energy Impact

One comment was made that the energy requirements in Tables 6–6, 7–18, and 7–22, draft EIS, do not take into account that ventilating air must be heated in winter.

Ventilating air must be heated in the winter whether or not NSPS are promulgated. The energy analysis is based on the incremental energy requirements between the base case and the emission control option under consideration. In all cases except one, the ventilating air requirements are significantly less than for the base case. End forming, the exception, has been excluded from the standards. Thus, any error introduced by not including the heating or ventilating air results in a lower energy savings than would actually be realized over the base case.

One commenter took exception to the statement in the preamble that the proposed standards would result in a net energy reduction because less coating per can would be used (based upon higher solids contents of waterborne coatings). Experience indicates that waterborne coatings require as much or more energy expenditure as solvent coatings. Further review or data collection concerning this issue was recommended. The commenter offered to submit data for both waterborne and solvent-based can coatings, upon EPA's request.

This comment was subsequently withdrawn by the commenter because appropriate inquiries to other canmakers led to the conclusion that the comment was not applicable to the industry as a whole. However, because the issue was raised, EPA considers that a general discussion of energy requirements is appropriate. It is assumed that the comment applies only to two-piece cans because the commenter's company makes only that type of can. Under some conditions, cure oven energy requirements for waterborne coatings for two-piece cans may be higher than for solvent-borne coatings. As discussed in Chapter 3 of the proposal BID, when waterborne coatings are used, exhaust air flow through the cure oven is based on considerations other than the lower explosive limit. Sufficient air must pass through the oven to clear the VOC and compounds that may be formed during the curing process. In general, air flows are about the same as when solvent-borne coatings are used.

In such a case the energy to heat and vaporize the water content of the coating would be greater than that required for an equivalent volume of VOC. However, energy required to heat and vaporize water or VOC is less than 10 percent of the total energy requirements when pin ovens are used. The greater portion of the energy requirements are for heating the air, heating the cans, and heating the pins. Similar considerations would apply to other than pin-type ovens.

In determining incremental energy impacts, both the base case and regulatory alternative energy requirements were based on the use of waterborne coatings. Because the energy impact is based on the difference between the base case and the alternatives under analysis and for the reasons cited above, the energy analyses are considered to be sufficiently accurate for standards development.

Environmental Impact

Two commenters stated that emission reductions will occur naturally as a result of conversion from three-piece to two-piece can production. Coating material used for the manufacture of two-piece cans is approximately 28 percent less than the coating material used for the manufacture of three-piece cans, regardless of whether the material used is conventional high solvent or RACT. Therefore, a net emission reduction results with the shift from three-piece cans to two-piece cans. This reduction far outweighs any reduction that will occur as a result of implementation of NSPS.

EPA agrees that there has been a significant reduction in VOC emissions as a result of the trend away from three-piece cans to two-piece cans. Emission data to date substantiate this. It is also true that reduction attainable through the promulgation of the beverage can surface coating NSPS will be much less than that achievable upon complete implementation of the RACT program. However, EPA is required under Section 111 of the Clean Air Act to promulgate NSPS for industries within source categories on the Priority List where, as in the case of this industry, application of control technology will achieve significant reduction beyond that achieved without NSPS. Application of BDT, which for this industry is the use of coatings with lower organic solvent content than RACT coatings, would achieve such a reduction. As a result, Section 111 requires EPA to promulgate standards reflecting such application.

Legal Considerations

Two canmakers were concerned that moving an existing plant to another site would subject the plant to NSPS or State new source emission limitations.

Movement of an affected facility to another site, in itself, is exempted from NSPS under § 60.14(e)(6). This exemption applies to 40 CFR 60 only. State and local regulations and other Federal regulations covering prevention of significant deterioration or new source review could apply.

Two commenters stated that the Agency's definition of an affected facility as any coating operation, as opposed to an entire line or an entire manufacturing plant, may not provide the same degree of latitude as the existing "bubble concept" and may limit methods of compliance and preclude the use of alternative compliance procedures based on total plant emissions. If the total facility emissions are equivalent to NSPS limitations using an alternate compliance plan, there is no detriment to the environment; therefore, an alternate compliance plan should be permissible. Particularly in a facility that would have a combination of NSPS and RACT limitations, an alternate compliance plan should be allowed. This would permit the facility to use the same materials for all lines, NSPS and RACT in combination. This plan would improve implementation of an air pollution control program.

The "bubble concept" refers to application of a standard to an entire plant rather than to individual emission points, although emission ceilings may concurrently be assigned to individual emission points. The term "affected facility" refers to the particular portion of a plant to which a standard applies. In this case the affected facility has been defined as a surface coating operation, which consists of a coating application station(s), flashoff area(s), and cure oven. The choice of the affected facility for any standard is based on the Agency's interpretation of the Clean Air Act, as amended, and judicial construction of its meaning. Under Section 111, the NSPS must apply to "new sources"; a "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" [Section 111(a)(3)]. Most industrial plants, however, consist of numerous pieces or groups of equipment that emit air pollutants and that might be viewed as "sources." EPA uses the term "affected facility" to designate the equipment, within a particular kind of plant, that is chosen as the "source" covered by a given standard.

In choosing the affected facility, EPA must decide which pieces or groups of equipment are the appropriate units for separate emission standards in the particular industrial context involved. The Agency does this by examining the situation in light of the terms and purpose of Section 111. One major consideration in this examination is that the use of a narrower definition results in bringing replacement equipment under the NSPS sooner; if, for example, an entire plant were designated the affected facility, no part of the plant would be covered by the standard unless the plant as a whole were "modified." If, on the other hand, each piece of equipment were designated the affected facility, as each piece were replaced, the replacement piece would be a new source subject to the standard. Because the purpose of Section 111 is to minimize emissions by application of the best demonstrated control technology (considering cost, other health and environmental effects, and energy

requirements) at all new, modified, or reconstructed sources, the presumption is that a narrower designation of the affected facility is proper. This designation insures that new emission sources within plants will be brought under coverage of the standards as they are installed. This presumption can be overcome where the impacts atttributable to the narrower designation are unreasonable in the light of the emissions reduction resulting from the selection of that definition.

The Agency has determined that in these standards the selection of each coating operation as the affected facility would not result in unreasonable impacts. It is technologically and economically feasible to control each surface coating operation. Choosing a combination of surface coating operations or the whole plant as the affected facility would be inconsistent with the language and intent underlying Section 111 because this broader definition would delay NSPS coverage of new facilities within the plant. Bubbling emissions at NSPS-regulated facilities with emissions at RACT facilities could permit all NSPS-regulated facilities in a plant to achieve less than BDT-level control. This would be inconsistent with Section 111's requirement that emissions at NSPS-regulated facilities be controlled to the level reflecting application of BDT. Therefore, the Agency has selected each surface coating operation as the affected facility for these standards.

One commenter stated that EPA's banking policy provides a built-in incentive for industry to develop materials superior to RACT. Resulting reduction in emissions from existing plants will far outweigh any benefits that might result from the implementation of NSPS.

The NSPS program does not prevent existing plants from banking emissions. NSPS are emission limits for new, modified, and reconstructed affected facilities based on BDT. In accordance with Section 111, these standards insure at least a specified minimum level of control at new, modified, and reconstructed facilities, wherever located—including those for which banking and other economic incentives may not be sufficient to induce good control of VOC emissions in the absence of NSPS.

One commenter was concerned that the promulgation of NSPS would jeopardize the ongoing RACT program if a new line were added to an existing plant, which is very common in the can business. The new line would be governed by NSPS limitations. Different coatings would be required for use on the new line than on the old line. Maintaining inventory and regulating the use of the two different sets of coatings for the production of the same can would be unmanageable. If the plant used alternate compliance, a complicated calculation scheme would be needed to demonstrate compliance with both NSPS and RACT. The dual system of RACT and NSPS in a plant will not work and will lead to demise of one or another in terms of practicality. Either the entire facility will be switched to NSPS, or RACT materials will be incinerated on NSPS lines. This concept is contrary to the recent U.S. EPA policy of discouraging the use of afterburners.

EPA considers that the situation that would result from the addition of a new line subject to NSPS to an existing plant appears to be no different from the situation in existing plants that make more than one type of beverage can, each of which may require different types of coating. The same procedures used to maintain inventories and regulate the use of different coatings in the latter plant are considered to be applicable to the situation described in the comment.

The procedures outlined for determining compliance for plants using RACT coatings and in the draft regulation for plants using NSPS coatings are not incompatible and permit the use of RACT coatings on one line and NSPS coatings on another. Furthermore, in enacting Section 111, Congress recognized that to enhance air quality over the long run it is important that new sources within a plant achieve limits based on the best demonstrated technology, irrespective of the level of control at existing sources within the plant.

Compliance of the NSPS affected facilities in a can plant would be determined using volume of coatings, VOC content thereof, and diluent solvent used in the affected facility by the procedures presented in the proposed regulations. Compliance of that portion of the plant subject to RACT would be in accord with provisions of the applicable State and local regulations. The data required for these calculations are considered to be those that any prudent manufacturer would maintain even if these standards were not promulgated.

One commenter felt that the information needed by EPA to determine compliance and to calculate emission inventories could be done with annual reports as opposed to monthly compliance determinations. These reports would only need to list each coating used by the plant along with kilograms of VOC per litre of solids and actual usage amounts. Those plants required to run control equipment would also have to report the average percentage of VOC reduction by the equipment and the number of production hours that the control equipment was not running, which could be backed up by a simple chart record.

Annual compilations are not considered an acceptable basis for determining compliance. Such an approach would permit a wide fluctuation in the mass of VOC emitted to the atmosphere at any one time. All of the canmakers contacted during the development of the standards reported maintaining coating-usage data on at least a monthly basis. As stated in a subsequent section of this preamble, EPA has investigated alternatives for reducing recordkeeping and reporting burdens and has changed the requirement for immediate reporting of noncompliance to semiannual reporting.

The promulgated regulations do not require reporting the average percentage of VOC reduction if an incinerator was used, or the number of hours the control system was not operating. Where compliance is achieved through the use of incineration, the owner or operator is required to identify and report, semiannually, all 3-hour periods during which the operating temperature, when cans are being processed, is more than 28° C below the average temperatures of the device during the most recent performance test or, for catalytic incinerators, when the average temperature difference is less than 80 percent of that determined during the most recent performance test. The destruction efficiency of the control device determined during the most recent performance test is used in determining compliance during any calendar month.

Test Methods and Methodology

Two commenters questioned the relationship of the proposed standards and the use of Reference Method 24 for determining compliance. Recommendations were made that the proposed standards should include a "cushion" that would allow for differences in test findings resulting from variation of the three experimentally determined physical constants used to calculate VOC content of coatings. Upward readjustment of the proposed standards to at least RACT level is required to avoid capricious erroneous noncompliance findings.

EPA recognizes the potential variability in the results when Method 24 is used to analyze waterborne coatings. The promulgated regulation

requires that, when Method 24 data are used to determine VOC content of waterborne coatings for compliance determinations, they be adjusted as described in Section 4.4 of Method 24.

If the VOC level of a waterborne coating, based on formulation, is at or below the standard, there is less than one chance in 10,000 that the Method 24 adjusted results would show the VOC level to be above the standard. The Agency considers this risk insignificant compared to the usefulness of Method 24 in determining compliance.

Reporting and Recordkeeping

One commenter stated that the recordkeeping requirements are unnecessarily tedious and time consuming, ask for much nonessential information, and necessitate intimidating and complex calculations. Production people would be required to do day-to-day and even hour-to-hour monitoring. The recordkeeping requirements penalize manufacturers that must meet the standard using control equipment instead of compliance coatings. The Agency's estimate that the proposed requirements would cost the industry 12 person-years over the first 5 years of the standards is unrealistically low. The commenter added that his company has less than 10 percent of the nation's two-piece can business, and conservatively estimates a cost of 2.3 person-years over the first 5 years of the standards. Even if the Agency's estimate is correct, the requirements are unnecessarily involved and are another example of an inflationary, nonproductive expense imposed upon industry by a governmental agency.

EPA has been investigating alternative ways of reducing monitoring, recordkeeping and reporting burdens on owners and operators. The goal is to reduce all recordkeeping and reporting that is not essential to insuring proper operation and maintenance. After reviewing the requirements in the proposal, EPA determined that monitoring and compiling data are essential for both the owner or operator and EPA to insure proper operation and maintenance. A responsible owner or operator would need monitoring information compiled in a usable form to determine when adjustments in the control system are needed to insure that it is performing at its intended effectiveness level. Because EPA judges that monitoring and recordkeeping are essential for proper operation and maintenance, these requirements have not been changed since proposal. It was judged, however, that immediate reporting of noncompliance with the standards is not essential to EPA. Semiannual reporting is considered sufficient to enable EPA to discharge its enforcement responsibility. Therefore, after initial performance testing, the requirement to report immediately all instances of noncompliance, as required in the proposal package, has been changed to require only semiannual reports. Reports required under the general provisions of 40 CFR part 60 remain unchanged. States delegated the authority to enforce these standards remain free to impose their own reporting requirements in conjunction with this regulation.

EPA disagrees that day-to-day or hour-to-hour monitoring will be required. Compliance is determined on a monthly basis and requires data that any prudent manufacturer would normally maintain. For facilities using waterborne coatings, required data consist of the volume and VOC content of each coating and the volume and density of each diluent VOC solvent used during each calendar month. When an emission control system is used, the most recently determined overall reduction efficiency of the system also is required.

Recordkeeping provisions of the proposed standards require maintaining records of all data and calculations for at least 2 years. In addition, records of incinerator operating temperatures are required if incineration is used, as are data on daily solvent recovery if a solvent recovery system is used. Incinerator temperatures and daily solvent recovery data are considered as essential to the operation of these devices and would be generated, maintained, and examined, whether or not required by the standards.

Details of the estimate that 12 person-years would be required by industry during the first 5 years of the standard are contained in the Reports Impact Analysis (Docket Item II–1–53). The estimate of industry requirements during the first 5 years has been revised downward to 11 person years as a result of the changes between proposal and promulgation (Docket Item IV–J–2). In a subsequent discussion the commenter stated that the 2.3 person-years was a worst case estimate based on all existing facilities being modified or reconstructed during 1980–1985.

It is EPA's judgment that the estimates are based on best available data, that the estimates are realistic, and that the requirements are not inflationary.

Miscellaneous

One commenter felt that the draft EIS and the proposed preamble and regulation are much more complex and lengthy than necessary. Discussion of incineration and the three-piece can should be eliminated.

EPA considered that the material in the draft EIS and in the proposal preamble and regulation was necessary to present the technical basis and the rationale for the development of the proposed standards. The beverage can surface coating industry is complex, involving as many as eleven coating operations on five separate items. Discussion of each of these was considered necessary to determine the scope and level of the proposed standards. A discussion of incineration was considered essential because one canmaker had recently constructed two plants using solvent-borne coatings. Also inceneration is considered to be an affordable and reasonable alternative to the use of waterborne coatings.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to identify readily and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket [except for certain materials noted in Section 307(d)(7)(A)] will serve as the record in case of judicial review.

Miscellaneous

The effective date of this regulation is August 25, 1983. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities for which construction, reconstruction, or modification was commenced after the date of proposal (November 26, 1980).

As prescribed by Section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

total mass of VOC per volume of coating solids before and after the incinerator, capture efficiency, and the destruction efficiency of the incinerator used to attain compliance with the applicable emission limit specified under § 60.492. The owner or operator shall also include a description of the method used to establish the amount of VOC captured by the capture system and sent to the control device.

(b) Following the initial performance test, each owner or operator shall submit for each semiannual period ending June 30 and December 31 a written report to the Administrator of exceedances of VOC content and incinerator operating temperatures when compliance with § 60.492 is achieved through the use of incineration. All semiannual reports shall be postmarked by the 30th day following the end of each semiannual period. For the purposes of these reports, exceedances are defined as:

(1) Each performance period in which the volume-weighted average of the total mass of VOC per volume of coating solids, after the control device, if capture devices and control systems are used, is greater than the limit specified under § 60.492.

(2) Where compliance with § 60.492 is achieved through the use of thermal incineration, each 3-hour period when cans are processed, during which the average temperature of the device was more than 28° C below the average temperature of the device during the most recent performance test at which destruction efficiency was determined as specified under § 60.493.

(3) Where compliance with § 60.492 is achieved through the use of catalytic incineration, each 3-hour period when cans are being processed, during which the average temperature of the device immediately before the catalyst bed is more than 28° C below the average temperature of the device immediately before the catalyst bed during the most recent performance test at which destruction efficiency was determined as specified under § 60.493 and all 3-hour periods, when cans are being processed, during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference across the catalyst bed during the most recent performance test at which destruction efficiency was determined as specified under § 60.493.

(c) Each owner or operator subject to the provisions of this subpart shall maintain at the source, for a period of at least 2 years, records of all data and calculations used to determine VOC emissions from each affected facility in the initial and monthly performance tests. Where compliance is achieved through the use of thermal incineration, each owner or operator shall maintain, at the source, daily records of the incinerator combustion chamber temperature. If catalytic incineration is used, the owner or operator shall maintain at the source daily records of the gas temperature, both upstream and downstream of the incinerator catalyst bed. Where compliance is achieved through the use of a solvent recovery system, the owner or operator shall maintain at the source daily records of the amount of solvent recovered by the system for each affected facility.

(d) The requirements of this subsection remain in force until and unless EPA, in delegating enforcement authority to a State under Section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected facilities within the State will be relieved of the obligation to comply with this subsection, provided that they comply with the requirements established by the State.

(Approved by the Office of Management and Budget under control number 2060–0001)

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1714))

§ 60.496 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8, shall be used to conduct performance tests.

(1) Reference Method 24, an equivalent or alternative method approved by the Administrator, or manufacturers formulation for data from which the VOC content of the coatings used for each affected facility can be calculated. In the event of dispute, Reference Method 24 shall be the referee method. When VOC content of waterborne coatings, determined from data generated by Reference Method 24, is used to determine compliance of affected facilities, the results of the Method 24 analysis shall be adjusted as described in Section 4.4 of Method 24.

(2) Reference Method 25 or an equivalent or alternative method for the determination of the VOC concentration in the effluent gas entering and leaving the control device for each stack equipped with an emission control device. The owner or operator shall notify the Administrator 30 days in advance of any State test using Reference Method 25. The following reference methods are to be used in conjunction with Reference Method 25:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 for velocity and volumetric flow rate,

(iii) Method 3 for gas analysis, and

(iv) Method 4 for stack gas moisture.

(b) For Reference Method 24, the coating sample must be a 1-litre sample collected in a 1-litre container at a point where the sample will be representative of the coating material.

(c) For Reference Method 25, the sampling time for each of three runs must be at least 1 hour. The minimum sample volume must be 0.003 dscm except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The Administrator will approve the sampling of representative stacks on a case-by-case basis if the owner or operator can demonstrate to the satisfaction of the Administrator that the testing of representative stacks would yield results comparable to those that would be obtained by testing all stacks.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

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For the initial performance test, the overall reduction efficiency (R) shall be determined as prescribed in A, B, and C below. In subsequent months, the owner or operator may use the most recently determined overall reduction efficiency for the performance test providing control device and capture system operating conditions have not changed. The procedure in A, B, and C, below, shall be repeated when directed by the Administrator or when the owner or operator elects to operate the control device or capture system at conditions different from the initial performance test.

(A) Determine the fraction (F) of total VOC used by the affected facility that enters the control device using the following equation:

$$F = S_e H_e + S_b H_b, \quad (5)$$

where H_e an H_b shall be determined by a method that has been previously approved by the Administrator. The owner or operator may use the values of S_e and S_b specified in Table 1 or other values determined by a method that has been previously approved by the Administrator.

TABLE 1.—DISTRIBUTION OF VOC EMISSIONS

Coating operation	Emission distribution	
	Coater/flashoff (S_e)	Curing oven (S_b)
Two-piece aluminum or steel can:		
Exterior base coat operation	0.75	0.25
Overvarnish coating operation	0.75	0.25
Inside spray coating operation	0.80	0.20

(B) Determine the destruction efficiency of the control device (E) using values of the volumetric flow rate of each of the gas streams and the VOC content (as carbon) of each of the gas streams in and out of the device by the following equation:

$$E = \frac{\sum_{i=1}^{n} Q_{bi} C_{bi} - \sum_{j=1}^{m} Q_{aj} C_{aj}}{\sum_{i=1}^{n} Q_{bi} C_{bi}}, \quad (6)$$

where n is the number of vents before the control device, and m is the number of vents after the control device.

(C) Determine overall reduction efficiency (R) using the following equation:

$$R = EF. \quad (7)$$

(ii) Calculate the volume-weighted average of the total mass of VOC per volume of coating solids (G) used during the calendar month for the affected facility using equations (1), (2), and (3).

(iii) Calculate the volume-weighted average of VOC emissions discharged to the atmosphere (N) during the calendar month by the following equation:

$$N = G \times [1-R]. \quad (8)$$

(iv) If the volume-weighted average of mass of VOC emitted to the atmosphere for the calendar month (N) is equal to or less than the applicable emission limit specified under § 60.492, the affected facility is in compliance.

(3) An owner or operator shall use the following procedure for each affected facility that uses a capture system and a control device that recovers the VOC (e.g., carbon adsorber) to comply with the applicable emission limit specified under § 60.492.

(i) Calculate the volume-weighted average of the total mass of VOC per unit volume of coating solids applied (G) used during the calendar month for the affected facility using equations (1), (2), and (3).

(ii) Calculate the total mass of VOC recovered (M_r) during each calendar month using the following equation:

$$M_r = L_r D_r \quad (9)$$

(iii) Calculate overall reduction efficiency of the control device (R) for the calendar month for the affected facility using the following equation:

$$R = \frac{M_r}{M_e + M_d} \quad (10)$$

(iv) Calculate the volume-weighted average mass of VOC discharged to the atmosphere (N) for the calendar month for the afffected facility using equation (8).

(v) If the weighted average of VOC emitted to the atmosphere for the calendar month (N) is equal to or less than the applicable emission limit specified under § 60.492, the affected facility is in compliance.

(Approved by the Office of Management and Budget under control number 2060-0001)

§ 60.494 Monitoring of emissions and operations.

The owner or operator of an affected facility that uses a capture system and an incinerator to comply with the emission limits specified under § 60.492 shall install, calibrate, maintain, and operate temperature measurement devices as prescribed below.

(a) Where thermal incineration is used, a temperature measurement device shall be installed in the firebox. Where catalytic incineration is used, temperature measurement devices shall be installed in the gas stream immediately before and after the catalyst bed.

(b) Each temperature measurement device shall be installed, calibrated, and maintained according to the manufacturer's specifications. The device shall have an accuracy the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5° C.

(c) Each temperature measurement device shall be equipped with a recording device so that a permanent continuous record is produced.

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(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414)

§ 60.495 Reporting and recordkeeping requirements.

(a) The owner or operator of an affected facility shall include the following data in the initial compliance report required under § 60.8(a).

(1) Where only coatings which individually have a VOC content equal to or less than the limits specified under § 60.492 are used, and no VOC is added to the coating during the application or distribution process, the owner or operator shall provide a list of the coatings used for each affected facility and the VOC content of each coating calculated fromdata determined using Reference Method 24 or supplies by the manufacturers of the coatings.

(2) Where one or more coatings which individually have a VOC content greater than the limits specified under § 60.492 are used or where VOC are added or used in the coating process, the owner or operator shall report for each affected facility the volume-weighted average of the total mass of VOC per volume of coating solids.

(3) Where compliance is achieved through the use of incineration, the ouner or operator shall include in the initial performance test required under § 60.8(a) the combustion temperature (or the gas temperature upstream and downstream of the catalyst bed), the

entering the atmosphere (parts per million as carbon)
C_b = the VOC concentration in each gas stream entering the control device (parts per million as carbon)
D_c = density of each coating, as received (kilograms per litre)
D_d = density of each VOC-solvent added to coatings (kilograms per litre)
D_r = density of VOC-solvent recovered by an emission control device (kilograms per litre)
E = VOC destruction efficiency of the control device (fraction)
F = the proportion of total VOC emitted by an affected facility which enters the control device to total emissions (fraction)
G = the volume-weighted average of VOC in coatings consumed in a calendar month per volume of coating solids applied (kilograms per litre of coating solids)
H_a = the fraction of VOC emitted at the coater and flashoff areas captured by a collection system
H_b = the fraction of VOC emitted at the cure oven captured by a collection system
L_c = the volume of each coating consumed, as received (litres)
L_d = the volume of each VOC-solvent added to coatings (litres)
L_r = the volume of VOC-solvent recovered by an emission control device (litres)
L_s = the volume of coating solids consumed (litres)
M_d = the mass of VOC-solvent added to coatings (kilograms)
M_o = the mass of VOC-solvent in coatings consumed, as received (kilograms)
M_r = the mass of VOC-solvent recovered by emission control device (kilograms)
N = the volume-weighted average mass of VOC emissions to atmosphere per unit volume of coating solids applied (kilograms per litre of coating solids)
Q_a = the volumetric flow rate of each gas stream leaving the control device and entering the atmosphere (dry standard cubic meters per hour)
Q_b = the volumetric flow of each gas stream entering the control device (dry standard cubic meters per hour)
R = the overall emission reduction efficiency for an affected facility (fraction)
S_a = the fraction of VOC in coating and diluent VOC-solvent emitted at the coater and flashoff area for a coating operation
S_b = the fraction of VOC in coating and diluent solvent emitted at the cure oven for a coating operation
V_s = the proportion of solids in each coating, as received (fraction by volume)
W_o = the proportion of VOC in each coating, as received (fraction by weight).

§ 60.492 Standards for volatile organic compounds.

On or after the date on which the initial performance test required by § 60.8(a) is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge of VOC emissions to the atmoshpere that exceed the following volume-weighted calendar-month average emissions:

(a) 0.29 kilogram of VOC per litre of coating solids from each two-piece can exterior base coating operation, except clear base coat;

(b) 0.46 kilogram of VOC per litre of coating solids from each two-piece can clear base coating operation and from each overvarnish coating operation; and

(c) 0.89 kilogram of VOC per litre of coating solids from each two-piece can inside spray coating operation.

§ 60.493 Performance test and compliance provisions.

(a) Section 60.8(d) does not apply to monthly performance tests and § 60.8(f) does not apply to the performance test procedures required by this subpart.

(b) The owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8(a) and thereafter a performance test each calendar month for each affected facility.

(1) The owner or operator shall use the following procedures for each affected facility that does not use a capture system and a control device to comply with the emission limit specified under § 60.492. The owner or operator shall determine the VOC-content of the coatings from formulation data supplied by the manufacturer of the coating or by an analysis of each coating, as received, using Reference Method 24. The Administrator may require the owner or operator who uses formulation data supplied by the manufacturer of the coating to determine the VOC content of coatings using Reference Method 24 or an equivalent or alternative method. The owner or operator shall determine from company records the volume of coating and the mass of VOC-solvent added to coatings. If a common coating distribution system serves more than one affected facility or serves both affected and exiting facilities, the owner or operator shall estimate the volume of coating used at each facility by using the average dry weight of coating, number of cans, and size of cans being processed by each affected and existing facility or by other procedures acceptable to the Administrator.

(i) Calculate the volume-weighted average of the total mass of VOC per volume of coating solids used during the calendar month for each affected facility, except as provided under § 60.493(b)(1)(iv). The volume-weighted average of the total mass of VOC per volume of coating solids used each calendar month will be determined by the following procedures.

(A) Calculate the mass of VOC used ($M_o + M_d$) during the calendar month for the affected facility by the following equation:

$$M_o + M_d = \sum_{i=1}^{n} L_{ci} D_{ci} W_{oi} + \sum_{j=1}^{m} L_{dj} D_{dj} \quad (1)$$

[$\Sigma L_{dj} D_{dj}$ will be 0 if no VOC solvent is added to the coatings, as received.] where n is the number of different coatings used during the calendar month and m is the number of different diluent VOC-solvents used during the calendar month.

(B) Calculate the total volume of coating solids used (L_s) in the calendar month for the affected facility by the following equation:

$$L_s = \sum_{i=1}^{n} L_{ci} V_{si}, \quad (2)$$

where n is the number of different coatings used during the calendar month.

(C) Calculate the volume-weighed average mass of VOC per volume of solids used (G) during the calendar month for the affected facility by the following equation:

$$G = \frac{M_o + M_d}{L^T{}_{2s}}. \quad (3)$$

(ii) Calculate the volume-weighted average of VOC emissions discharged to the atmosphere (N) during the calendar month for the affected facility by the following equation:

(4)

N = G.

(iii) Where the value of the volume-weighted average of mass of VOC per volume of solids discharged to the atmosphere (N) is equal to or less than the applicable emission limit specified under § 60.492, the affected facility is in compliance.

(iv) If each individual coating used by an affected facility has a VOC content equal to or less than the limit specified under § 60.492, the affected facility is in compliance provided no VOC-solvents are added to the coating during distribution or application.

(2) An owner or operator shall use the following procedures for each affected facility that uses a capture system and a control device that destroys VOC (e.g., incinerator) to comply with the emission limit specified under § 60.492.

(i) Determine the overall reduction efficiency (R) for the capture system and control device.

The standard requires that owners or operators of affected facilities submit three types of reports, those required under the General Provisions of 40 CFR Part 60, initial performance test reports, and semiannual reports of instances in which the VOC content of coatings used exceeds the allowable level established in the standard and instances in which incinerator operating temperatures vary significantly from those used to establish emission control system efficiencies where compliance is achieved through the use of incineration.

This regulation will be reviewed no later than four years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in this regulation will be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to insure that cost was carefully considered in determining BDT. The economic impact assessment is included in the BID for the proposed standards.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because it would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be major. There will be no increase in industrywide annualized costs as a result of this regulation. No significant increase in price is associated with the proposed standards; thus there would be no "major increase in costs or prices" specified as the second criterion in the Order. The economic analysis of the proposed standards' effects on the industry did not indicate any significant adverse effects on competition, investment, productivity, employment, innovation, or the ability of U.S. firms to compete with foreign firms (the third criterion in the Order).

This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are available for public inspection in the docket referenced in the address section of this preamble.

Information collection requirements contained in this regulation (Sections 60.493, 60.494, and 60.495) have been approved by OMB under the provision of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060-0001.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc, Tires, Incorporation by reference, Can surface coating.

Dated August 18, 1983.

William D. Ruckelshaus,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended by adding Subpart WW as follows:

Subpart WW—Standards of Performance for the Beverage Can Surface Coating Industry

Sec.

60.490 Applicability and designation of affected facility.
60.491 Definitions.
60.492 Standards for volatile organic compounds.
60.493 Performance test and compliance provisions.
60.494 Monitoring of emissions and operations.
60.495 Reporting and recordkeeping requirements.
60.496 Test methods and procedures.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411 and 7601(a)], and additional authority, as noted below.

§ 60.490 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in beverage can surface coating lines: each exterior base coat operation, each overvarnish coating operation, and each inside spray coating operation.

(b) The provisions of this subpart apply to each affected facility which is identified in paragraph (a) of this section and commences construction, modification, or reconstruction after November 26, 1980.

§ 60.491 Definitions.

(a) All terms which are used in this subpart and are not defined below are given the same meaning as in the Act and Subpart A of this part.

(1) *Beverage can* means any two-piece steel or aluminum container in which soft drinks or beer, including malt liquor, are packaged. The definition does not include containers in which fruit or vegetable juices are packaged.

(2) *Exterior base coating operation* means the system on each beverage can surface coating line used to apply a coating to the exterior of a two-piece beverage can body. The exterior base coat provides corrosion resistance and a background for lithography or printing operations. The exterior base coat operation consists of the coating application station, flashoff area, and curing oven. The exterior base coat may be pigmented or clear (unpigmented).

(3) *Inside spray coating operation* means the system on each beverage can surface coating line used to apply a coating to the interior of a two-piece beverage can body. This coating provides a protective film between the contents of the beverage can and the metal can body. The inside spray coating operation consists of the coating application station, flashoff area, and curing oven. Multiple applications of an inside spray coating are considered to be a single coating operation.

(4) *Overvarnish coating operation* means the system on each beverage can surface coating line used to apply a coating over ink which reduces friction for automated beverage can filling equipment, provides gloss, and protects the finished beverage can body from abrasion and corrosion. The overvarnish coating is applied to two-piece beverage can bodies. The overvarnish coating operation consists of the coating application station, flashoff area, and curing oven.

(5) *Two-piece can* means any beverage can that consists of a body manufactured from a single piece of steel or aluminum and a top. Coatings for a two-piece can are usually applied after fabrication of the can body.

(6) *VOC content* means all volatile organic compounds (VOC) that are in a coating. VOC content is expressed in terms of kilograms of VOC per litre of coating solids.

(b) Notations used under § 60.493 of this subpart are defined below:

C_a = the VOC concentration in each gas stream leaving the control device and

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Part VII

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Rotogravure Printing and Coating of Flexible Vinyl and Urethane

ENVIRONMENAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2382-2]

Standards of Performance for New Stationary Sources; Rotogravure Printing and Coating of Flexible Vinyl and Urethane

AGENCY: Environmental Protection Agency (EPA).

ACTION: Supplemental Notice of Proposal Rule.

SUMMARY: This notice supplements the proposed rule on the standards of performance for Flexible vinyl coating and printing operations that appeared at page 2276 in the Federal Register of January 18, 1983 (48 FR 2276). This action is being taken to provide notice that the printing of flexible urethane coated fabrics is included in the proposed standard for flexible vinyl coating and printing operations and to solicit public comments on urethane printing only.

DATES: *Comments.* The proposed regulation is being reopened for comment concerning urethane only. Comments must be received on or before November 10, 1983.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to: Central Docket Section (LE-131), attention: Docket Number A-80-8, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460.

Background Information Document. The background information document (BID) for the proposed standard may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Flexible Vinyl Coating and Printing Operations—Background Information for Proposed Standards," EPA-450/3-81-016a.

Docket. Docket number A-80-8, containing supporting information used in developing the proposed standard, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Gene W. Smith, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number (919) 541-5624.

SUPPLEMENTARY INFORMATION: Flexible vinyl printing refers to the rotogravure process of printing and coating vinyl webs with any mixture of ink, coating solids, volatile organic compounds (VOC), and water that is applied to the web substrate of a rotogravure printing line. The web may consist of a vinyl coated substrate referred to as a supported web, or a vinyl sheet with no substrate, referred to as an unsupported web. Printing and coating methods for supported and unsupported products are essentially identical.

The comment period for the proposed standards for flexible vinyl coating and printing operations ended on April 1, 1983. During the comment period, a letter was received from a major manufacturer of flexible urethane produces. After reviewing the regulation and background information document, the commenter stated that there were no known technical or scientific reasons why the printing of flexible urethane coated fabrics should be regulated differently than the printing of flexible vinyl coated fabrics. The commenter further stated that regardless of the chemical compositioon of the coating, whether polyvinyl chloride (PVC) or urethane, the webs are finished by printing with solvent solutions of PVC, urethanes and/or acrylic resins.

Urethane and vinyl products are commonly printed as a continuous web on rotogravure equipment. At least two manufacturers sometimes use urethane webs and/or urethane inks on equipment normally used for vinyl products. The standard, which reflects the best demonstrated technology (BDT) for the vinyl industry, also reflects BDT for the urethane industry. The Administrator believes that urethane product manufacturers can achieve the emission standard at reasonable costs. Therefore, in the Administrator's judgment, based on the information presented by the commenter, it is reasonable to include the printing of flexible urethane coated fabrics in the proposed standards for flexible vinyl coating and printing operations, since the Agency has not investigated the environmental, energy, and economic impacts of the standard upon urethane product manufacturers, we are soliciting public comments on this issue.

Section 604 of the Regulatory Flexibility Act (RFA) requires that the Administrator certify whether regulations have a significant impact on a substantial number of small entities. There are approximately four companies that manufacture urethane products, one of which would be considered small. The economic analysis conducted for small vinyl manufacturers indicated no significant impacts. Similarly, it is not expected that this supplement, if promulgated, will significantly impact small businesses. Further, this supplement will have no impact on any other small entities.

Paperwork Reduction Act

The information provisions associated with the proposed rule which this notice proposes to amend will be submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980 U.S.C. 3501 et seq. Comments on these requirements should be submitted to the Office of Information and Regulatory Affairs of OMB marked Attention: Desk Officer for EPA. The final rule package will respond to any OMB or public comment on the information collection provisions.

Dated: September 28, 1983.

William D. Ruckelshaus,

Administrator.

List of Subjects in 40 CFR Part 60

Air pollution control, Intergovernmental relations, Paper and paper products industry.

PART 60—[AMENDED]

The proposed regulation published at 48 FR 2276, January 18, 1983 is amended as follows:

1. The authority for Part 60 is:

Authority: Sec. 111, 301(a) of the Clean Air Act as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

2. The heading for Subpart FFF is revised to read as follows:

Subpart FFF—Standards of Performance for Rotogravure Printing and Coating of Flexible Vinyl and Urethane

3. Paragraph (a) of §60.580 is revised to read as follows:

§ 60.580 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each rotogravure printing line used to print or coat flexible vinyl or urethane products.

* * * * *

4. In § 60.581, the definitions for "emission control devices", "emission control system", "ink", "Rotogravure printing line", and "vapor capture system" are revised. The term "Flexible vinyl products" is changed to "Flexible vinyl and urethane products", and the definition is revised to read as follows:

§ 60.581 Definitions and symbols.

(a) All terms used in this subpart, not defined below, are given the same meaning as in the Act or in Subpart A of this part.

"Emission control device" means any solvent recovery device used to control VOC emissions from flexible vinyl and urethane rotogravure printing lines.

"Emission control system" means the combination of an emission control device and a vapor capture system for the purpose of reducing VOC emissions from flexible vinyl and urethane rotogravure printing lines.

"Flexible vinyl and urethane products" means those products, except for resilient floor coverings (1977 SIC industry 3996), that consist of or contain a vinyl or urethane sheet or a vinyl or urethane coated web, and are more than 50 micrometers (0.002 inches) thick.

* * * * *

"Ink" means any mixture of ink, coating solids, VOC, and water that is applied to the web substrate of a flexible vinyl or urethane rotogravure printing line.

* * * * *

"Rotogravure printing line" means any number of rotogravure print stations and associated dryers capable of printing or coating simultaneously on the same continuous vinyl or urethane web or substrate, which is fed from a continuous roll.

"Vapor capture system" means any device or combination of devices designed to contain, collect, and route solvent vapors released from the flexible vinyl or urethane rotogravure printing line.

* * * * *

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Part II

Environmental Protection Agency

Standards of Performance for New Stationary Sources; Synthetic Organic Chemical Manufacturing Industry; Equipment Leaks of VOC, Reference Methods 18 and 22; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2297-2]

Standards of Performance for New Stationary Sources; Synthetic Organic Chemical Manufacturing Industry; Equipment Leaks of VOC, Reference Methods 18 and 22

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action promulgates standards of performance for equipment leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The standards were proposed in the Federal Register on January 5, 1981 (46 FR 1136). These standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination that emissions from the synthetic organic chemical manufacturing industry cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all newly constructed, modified, and reconstructed SOCMI process units to use the best demonstrated system of continuous emission reduction for equipment leaks of VOC, considering costs, nonair quality health and environmental impact and energy requirements.

DATES: Effective date: October 18, 1983.

These standards of performance become effective upon promulgation but apply to affected facilities for which construction or modification commenced after January 5, 1981.

Under Section 307(b)(1) of the Clean Air Act, judicial review of these standards of performance is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

The Director of the Federal Register approves the incorporation by reference of certain publications in 40 CFR effective on October 18, 1983.

ADDRESSES: *Background Information Documents.* The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Equipment Leaks of VOC in Synthetic Organic Chemicals Manufacturing Industry—Background Information for Promulgated Standards of Performance" (EPA-450/3-80-033b). The BID contains (1) a summary of all the public comments made on the proposed standards and EPA's responses to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final Environmental Impact Statement which summarizes the impacts of the promulgated standards. The BID for the proposed standards may be obtained from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161. Please refer to "VOC Fugitive Emissions in Synthetic Organic Chemicals Manufacturing Industry—Background Information for Proposed Standards," EPA-450/3-80-033b (NTIS PB81-152167). The additional information document (AID) describing emissions, emission reductions, and costs related to equipment leaks of VOC may also be obtained from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161. Please refer to "Fugitive Emission Sources of Organic Compounds—Additional Information on Emissions, Emission Reductions, and Costs," EPA-450/3-82-010 (NTIS PB82-217128).

Docket. A docket, number A-79-32, containing information considered by EPA in development of the promulgated standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Dimmick, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5578.

SUPPLEMENTARY INFORMATION:

Summary of Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> . . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

As prescribed by Section 111 of the Clean Air Act, promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

Standards of performance for equipment leaks of volatile organic compounds (VOC) in the synthetic organic chemical manufacturing industry (SOCMI) were proposed on January 5, 1981 (46 FR 1136).[1] The promulgated standards apply to specific equipment with the potential to leak VOC within process units operated to produce one or more of the organic chemicals listed in the standards. The equipment covered by the standards and grouped in a process unit are designated as the "affected facility" for determining applicability of the standards. A process unit is a group of equipment that can be used independently, if sufficient raw material and product storage capacity could be supplied, to produce one or more chemicals. Process units used to produce the chemicals covered by the standards may involve chemical synthesis, bilological synthesis, other processing, or physical operations, such as separation. A plant may be composed of one or more process units.

Valves, pumps, compressors, pressure relief devices, sampling systems, and open-ended lines in VOC services (that is, containing 10 percent or more VOC by weight) are the equipment covered by the standards. The standards require (1) a leak detection and repair program for valves in gas/vapor and light liquid service and pumps in light liquid service; (2) equipment for compressors, sampling systems, and open-ended lines; (3) no detectable emissions (500 ppm as determined by Reference Method 21) for pressure relief devices in gas/vapor service during normal operation. In response to comments on the proposed standards, EPA is exempting from the

[1] The proposed standards referred to fugitive emission sources of VOC as the air pollution emission points covered by the standards. The terminology fugitive emission sources can be confusing. The standards apply to equipment with the potential to leak VOC and, therefore, the promulgated standards refer to equipment leaks of VOC as the air pollution emission points covered by the standards. The Priority List (40 CFR 60.16) specifies fugitive emission sources within the SOCMI source category. Equipment leaks of VOC are included in fugitive emision sources for the purpose of the Priority List.

standards facilities producing less than 1,000 megagrams (Mg) of SOCMI chemicals per year, facilities processing only heavy liquids or solids, and facilities producing beverage alcohol. In addition, the final standards provide a procedure for determining the equivalency of alternative control measures similar to the proposed procedure.

Standards for Valves. The standards for valves have not substantially changed since proposal. They are based on a leak detection and repair program that requires (1) monthly monitoring for valves in gas/vapor and light liquid service, (2) an initial attempt at repairing these valves within 5 days after detection of a leak, (3) repair of leaking valves within 15 days after detection of the leak unless repair would require a process unit shutdown, and (4) repair of valves during the next process unit shutdown after repair is delayed until a process unit shutdown. Valves found not to leak for 2 successive months can be monitored quarterly until leaks are deteted. Monitoring of equipment to detect leaks is conducted in accordance with Reference Method 21 and a leak is defined as a measured organic concentration equal to or greater than 10,000 parts per million by volume (ppmv).

Two alternative standards have been provided for valves in gas/vapor and light liquid service in the final standards. These alternatives are (1) a limit of 2 percent of valves which may be leaking at any one time and (2) a skip-period leak detection and repair program for process units achieving less than 2 percent of their valves leaking. These alternative standards, although slightly different than the alternative standards included in the proposed standards, establish standards for owners and operators who design and operate low-peak process units. For low-leak process units, the costs of the monthly leak detection and repair program is unreasonably high in comparison to the emission reductions.

Standards for Pumps. The final standards include a leak detection and repair program that requires (1) monthly monitoring of pumps in light liquid service, (2) weekly visual inspections of the seals on pumps in light liquid service, (3) an attempt at repairing a pump within 5 days after detection of a leak, and (4) repair of a leaking pump within 15 days after detection of a seal failure or leak unless repair would require a process unit shutdown. Pumps that have repair delayed until a process unit shutdown must be repaired during the next process unit shutdown. If a pump cannot be repaired without the use of dual seals and barrier fluid systems or vented seal areas, a delay of repair is allowed to install the equipment. In this case, an owner or operator must install the equipment as soon as practicable but may take no longer than 6 months.

The proposed standards required the use of equipment. The use of equipment reduces more emissions than the monthly leak detection and repair program. Even though the standards have changed, pumps in light liquid service alternately could use the equipment specified in the proposed standards and, thereby, not be required to implement the monthly leak detection and repair program.

Standards for Compressors. The standards have not changed since proposal and require compressors to be equipped with seals having a barrier fluid system that prevents leakage of the process fluid to the atmosphere. The system must: (1) Use a barrier fluid that is something other than a light liquid or gaseous VOC; (2) either operate at a pressure greater than the compressor seal area pressure, or be equipped with a barrier fluid degassing reservoir connected by a closed vent system to a control device; and (3) be equipped with a sensor so that seal failures may be detected. When seal failure is detected, repair is required within 15 days unless repair would require a process unit shutdown. An initial attempt at repair is required within 5 days. If a compressor is equipped with a closed vent system to transport leakage from the seal to a control device, it is exempt from the above requirements.

Certain reciprocating compressors covered by virtue of modification and reconstruction may be exempt from the requirements for compressors. Some existing compressors are not designed to use the equipment required by the standards. For these compressors either new compressor or a new distance-piece would be required before compliance with the standards could be achieved. The cost impact of installing the required control equipment on these existing compressors is unreasonable. These compressors will be exempt from the standards until they are replaced by new compressors or the distance pieces are replaced.

Standards for Sampling Connections. The standards require that VOC purged from sampling connections be recycled to the process by a closed sampling loop or that these VOC be collected in a closed collection system for recycle or disposal without VOC emission to atmosphere. In-situ sampling systems are exempt from these requirements. These standards have not changed since proposal.

Standards for Open-ended Lines. The standards require that: (1) Open-ended lines be sealed with a second valve, cap, blind flange or plug except when the open-ended line is in use; and (2) if a second valve is used, the valve on the process side be closed first to avoid trapping VOC between the valves. These standards have not changed since proposal.

Standards for Pressure Relief Devices. The standards require that: (1) Pressure relief devices have "no detectable emissions" of VOC except in cases of overpressure relief; and (2) after each overpressure relief, pressure relief devices be returned to a state of no detectable emissions within 5 days. These standards have not changed since proposal. As noted in the preamble to the proposed standards, pressure relief devices are one of the few fugitive emission sources for which a performance standard can be established. There are a variety of alternative ways of complying with this standard. "No detectable emissions" of VOC, in this case, means 500 ppm or less above the background level as measured by Reference Method 21.

Standards for Control Devices. The standards include requirements for control devices used in conjunction with control of equipment leaks. The standards require: (1) That vapor recovery systems be designed and operated for at least 95 percent control; (2) that enclosed combustion devices be designed and operated to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C or to achieve 95 percent reduction; and (3) that flares (a) be operated with no assist or with air or steam assist, (b) be designed and operated with no visible missions except for periods of time not to exceed 5 minutes in any 2-hour period, (c) be operated with a flame present, and (d) meet other operational requirements including maximum exit gas velocities and minimum heat content values. Flares have been added to the approaches for achieving the standards since proposal. Otherwise, the standards for control devices have not changed since proposal.

Miscellaneous Provisions. Flanges, pressure relief devices in liquid service, equipment operating at subatmospheric pressures, and all equipment components in "heavy liquid" VOC service are excluded from the routine monitoring requirements of the proposed standards. Heavy liquids are defined as VOC liquids with vapor pressures less

than 0.3 kilopascals at 20°C. Even though the standards do not require monitoring these equipment for leaks, the standards require VOC leaks which are visually or otherwise detected from these equipment to be repaired within 15 days if a leak is confirmed using Reference Method 21. This provision improves current industry housekeeping practices for these pieces of equipment.

Under Section 111(h)(3), any person may request the Administrator to permit the use of an alternative means of emission limitation instead of a design, equipment, work practice or operational standard. The Administrator will permit the use of such alternative means if the Administrator determines, after notice and opportunity for a public hearing, that it will achieve emission reductions at least equivalent to those required by the design, equipment, work practice or operational standards. The permission will take the form of an amendment to the appropriate standards.

Compliance with the leak detection and repair program and equipment requirements will be assessed through semiannual reports, review of records, and by inspection. The semiannual reports provide a summary of the data recorded on leak detection and repair of valves, pumps, and of other equipment types. In response to public comments, requirements for routine reporting were reduced from quarterly to semiannual reporting. Notifications are still required as described in the General Provisions for new source standards (40 CFR 60.7).

The semiannual reports may be waived for affected facilities in States where the regulatory program has been delegated, if EPA, in the course of delegating such authority, approves reporting requirements or an alternative means of source surveillance adopted by the State. In these cases, such sources would be required to comply with the requirements adopted by the State.

Records of leak detection, repair attempts, and maintenance for equipment leaks of VOC are required by the standards. These records, along with semiannual reporting and plant inspections, will be used to enforce the standards. The records remain essentially the same as those in the proposed standards. Some changes have occurred because the requirements for the equipment covered by the standards have changed. In addition, EPA has made it clear that an owner or operator may keep the records for several affected facilities at one location in a plant rather than at each process unit.

Miscellaneous Actions. The General Provisions of Part 60 are being revised to provide technical amendments to the provisions in 40 CFR 60.7, 60.11, and 60.17. Also, Reference Method 18 is being added to Appendix A of Part 60 and Reference Method 22 is being revised. These methods will be used to determine compliance with the requirements for flares.

Summary of Impacts

Emission Reductions. The standards of performance will reduce equipment leaks of VOC from newly constructed, modified, and reconstructed process units in SOCMI by approximately 56 percent in comparison to those emissions that would result in the absence of the standards. The standards will cover about 830 newly constructed, modified, and reconstructed sources in 1985. The standards will reduce the emissions associated with current industry practices from approximately 83,000 to 37,000 Mg in 1985 (that is, 91,000 to 41,000 tons) for newly constructed, reconstructed, and modified process units.

Cost and Economic Impacts. The cost and economic impacts of the standards are reasonable. The standards will require an industry-wide capital investment over the 5-year period from 1981 to 1986 of approximately $44 million for those facilities which are newly constructed, reconstructed, or modified. The industry-wide net annualized cost will be about $14.6 million in 1985. This net annualized cost includes a credit resulting from "recovered" emissions. The costs will be distributed among 830 facilities affected during the 5-year period. Industry-wide price increases are not expected to result from these standards.

Other Impacts. The standards of performance will not increase the energy usage of SOCMI process units. In general, the controls required by the standards do not require energy. Futhermore, the effect of the standards will be to increase efficiency of raw material usage so that a net positive energy impact will result. Implementation of the standards will have no impact on solid waste within SOCMI. In contrast, the standards could also cause a small positive impact on water quality by containment of potential liquid leaks. The recordkeeping and reporting requirements will require an average of 65 industry person years annually for the years of 1983 and 1984.

The environmental, energy, and economic impacts are discussed in greater detail in the background information document for the promulgated standards. [See the ADDRESSES section of this preamble.]

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** (45 FR 18474, March 21, 1980) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the standards for equipment leaks of VOC in SOCMI recommended for proposal. This meeting was held on April 16, 1980. The meeting was open to the public, and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed in the **Federal Register** on January 5, 1981 (46 FR 1136). The preamble to the proposed standards discussed the availability of the background information document for the proposed standards which described in detail the regulatory alternatives considered and the impacts of those alternatives.

Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on March 3, 1981, at Research Triangle Park, North Carolina. The hearing was open to the public and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from January 5, 1981 to July 31, 1981. The comment period was extended to July 31, 1981, to allow interested parties to comment on several studies performed by EPA's Office of Research and Development which became available at proposal or after proposal. Fifty-six comment letters were received and 9 interested parties testified at the public hearing concerning issues relative to the proposed standards of performance for equipment leaks of VOC from SOCMI units.

EPA published an Additional Information Document (AID) in April of 1982. The AID contains a technical discussion of methodologies and estimates of emissions, emission reductions, and costs associated with control of equipment leaks of VOC. A notice of the availability of the AID and a request for comments on the AID was published in the **Federal Register** on May 7, 1982 (47 FR 19724). Fourteen letters were received containing comments on the AID.

Comments on the proposed standards and on the AID have been carefully considered and, where determined to be appropriate by the Administrator,

changes have been made in the proposed standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from industry, State and local air pollution control agencies, trade associations, and environmental groups. A detailed discussion of these comments and responses can be found in the BID for the promulgated standards. [See the **ADDRESSES** section of this preamble.] The comments and responses in the BID serve as the basis for the revisions which have been made to the standards between proposal and promulgation. Major changes made in the standards since proposal are indicated in the "Summary of Standards" section of the preamble. The major comments and responses are summarized in the next sections of this preamble. The comments and responses in this preamble have been combined into the following areas: Need for Standards, Selection of the Final Standards, Control Technology—Use of Flares, and Test Methods and Monitoring.

Need for Standards

Comment 1: Commenters questioned whether standards of performance are needed for SOCMI because SOCMI equipment leaks emit small quantities of VOC.

Response 1: SOCMI is a significant source of VOC emissions and equipment leaks of VOC are one of the primary contributors to the total VOC emissions from SOCMI. EPA estimates that 540,000 megagrams per year (Mg/yr) of VOC are emitted from all sources in SOCMI (docket item IV–B–24). This estimate of emissions is based on detailed studies of individual process source types including air oxidation processes, distillation operations, storage operations, carrier gas processes, equipment leaks, and secondary sources. Five hundred forty thousand Mg/yr is a significant quantity of VOC to be emitted as air pollution.

The significance of SOCMI VOC emissions is reflected in the Priority List, 40 CFR 60.16. Of the 59 major source categories on this list for which standards of performance were to be promulgated by 1982, the SOCMI source category ranked first. The Priority List consists of categories of air pollution sources that, in EPA's judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In developing the Priority List, major source categories were ranked according to three criteria specified in Section 111(f) of the Act: (1) The quantity of emissions from each source category, (2) the extent to which each pollutant endangers public health or welfare, and (3) the mobility and competitive nature of each stationary source category. Commenters have not presented any new information which would change the decision to list SOCMI on the Priority List.

Based on comments and information received during this rulemaking, EPA has revised the estimates of emissions of VOC from equipment leaks within SOCMI since the standards were proposed. The current estimate of 540,000 Mg/yr includes the revised emission estimates. Even with the revised emission estimates, the Administrator still considers SOCMI a source category that causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. It should be noted that because VOC emissions come from many, diverse source categories, each source category contributes a relatively small percentage to the large overall total emissions. Even though SOCMI may represent a small percentage of total VOC emissions, the magnitude of emissions from SOCMI is significant.

Since SOCMI is on the Priority List as a significant contributor to air pollution under section 111(f), standards of performance are required to be promulgated for those new sources within this source category for which the EPA can identify the best demonstrated technology (considering costs). EPA has identified several alternative systems of control capable of achieving additional emission reduction at reasonable cost at SOCMI sources. It is, therefore, reasonable for EPA to establish standards for these sources.

In addition, standards of performance have other benefits in addition to achieving emissions reductions. Standards of performance establish a degree of national uniformity to air pollution standards, and therefore, preclude situations in which some States may attract new industries as a result of having relaxed standards relative to other States. Further, standards of performance provide documentation that reduces uncertainty in evaluations of available control technology. This documentation includes identification and comprehensive analyses of alternative emission control technologies, development of associated costs, evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternate technologies. This documentation also provides an economic analysis that reveals the affordability of controls in a study of the economic impact of controls on an industry.

Comment 2: Commenters stated that there is no need for the standards because emissions of VOC in SOCMI are adequately controlled by other regulations, specifically:

(a) National ambient air quality standards (NAAQS) and the State implementation plans (SIP) to implement these standards;

(b) National emission standards for hazardous air pollutants (NESHAP); and

(c) Occupational safety and health standards under the Occupational Safety and Health Act (OSHA).

Response 2: Standards of performance required by Section 111 play a unique role under the Clean Air Act. The main purpose of standards of performance is to require new sources, wherever located, to reduce emissions to the level achievable by the *best* technological system of continuous emission reduction considering the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements [(Section 111(a)(1))]. Congress recognized that establishing such standards would minimize increases in air pollution from new sources, thereby improving air quality as the Nation's industrial base is replaced over the long term. The role of standards of performance in achieving the goals set forth in the Clean Air Act is distinct from that of other regulations.

(a) *NAAQS and SIP:* Reasonably available control technology (RACT) requirements apply to existing sources and are based on SIP's developed for the purpose of attaining the NAAQS. Standards of performance supplement the role played by RACT and the two types of control do not conflict. In the few areas where RACT-level control is already in place, the environmental impact of standards of performance will be smaller than calculated. EPA has determined, however, that existing RACT-level facilities that become subject to the standards of performance (e.g., through modification) will be achieving additional emission reductions at reasonable costs. In most areas of the Nation, RACT-level controls are not in place and the standards fulfill their role of preventing new air pollution from developing as the Nation's industrial base is replaced.

(b) *NESHAP:* NESHAP, as mandated under Section 112 of the Clean Air Act, are distinctly separate from NAAQS or new source standards of performance. NESHAP are developed to control

pollutants that are hazardous because they are carcinogens or the cause of other serious diseases. Some of the individual SOCMI chemicals have been identified as hazardous air pollutants and some SOCMI units may be affected by NESHAP regulations. However, SOCMI VOC emissions as a class have not been identified as hazardous pollutants, and therefore, are not subject to NESHAP.

(c) *OSHA:* Many of the chemicals covered by the standards are also listed in Table Z-1, Toxic and Hazardous Substances, in the general provisions for OSHA (29 CFR 1910.1000), and some of these chemicals are also covered by more specific health standards under OSHA. As a consequence, the SOCMI standards and the OSHA standards may affect the same equipment in VOC service. However, this possibility does not negate the need for the standards.

The SOCMI standards of performance serve to limit mass emission rates directly; OSHA standards for toxic chemicals generally do not. Under OSHA, control of emission sources may include substitution with less hazardous materials, process modification, worker rotation, process or worker isolation, ventilation controls, or modification of work practices. These controls reduce occupational exposures, but they do not necessarily reduce the mass rate of VOC emissions to the atmosphere. Furthermore, OSHA regulations would require control to different concentration levels, depending on the toxicity of a specific chemical, while the standards of performance require emission control for all VOC. Relying on indirect controls that may or may not reduce emissions that would degrade air quality would be an unreasonable approach to reducing emissions of VOC.

Comment 3: Commenters claimed that the standards are not needed to protect the public health and welfare. These commenters noted that the ambient air quality standard for ozone which is set to protect the public has recently been raised. The commenters continued by adding that, because most of the country is in compliance with the ozone standard, the public health and welfare is already protected and, therefore, the standards of performance are not needed.

Response 3: Standards of performance are not directly designed to achieve the ambient air quality goals. Their overriding purpose is rather to minimize emissions at all new and modified sources, wherever they are located, to prevent new pollution problems from developing, and to enhance air quality as the Nation's industrial base is replaced. Thus, the standards may not bear directly on current attainment or nonattainment of NAAQS for ozone. Nonetheless, they do make room for future industrial growth while preventing future air quality problems—complementing the prevention of significant deterioration (PSD) and nonattainment rules as a means of achieving and maintaining the NAAQS. Clearly, residents in both attainment and non-attainment areas will ultimately benefit from such standards.

Basis for the Final Standards

Comment: Several commenters questioned EPA's selection of the proposed standards. The commenters felt that other regulatory options would have been more cost-effective and, therefore, should have been chosen. Referring to the regulatory alternatives presented in EPA-450/3-80-033a, some commenters recommended selection of regulatory alternatives II or III instead of regulatory alternative IV. Some commenters also suggested that EPA select the final standards after considering the cost effectiveness of each control technique for each piece of equipment covered by the standards. Other commenters recommended selection of regulatory alternative IV.

Response: Section 111 of the Clean Air Act, as amended, requires that standards of performance be based on the best system of continuous emission reduction that has been adequately demonstrated, considering costs, nonair quality health and environmental impacts and energy requirements. The control techniques for equipment leaks of VOC have been adequately demonstrated. The nonair quality health and environmental impacts associated with implementaion of the standards are positive.

Since proposal, EPA has decided to accept the suggestions of the commenters and focus further on cost effectiveness as the basis for the selection of final standards. In using cost effectiveness of individual control techniques as the basis for selection, the regulatory alternative framework presented in the BID for the proposed standards is no longer pertinent and is not presented. The control strategies represented by the regulatory alternatives were, however, considered in the selection of the final standards. In choosing among the control techniques for each type of equipment covered by the standards, EPA first considered their relative cost effectiveness. Then, for the control techniques which were selected as the most effective with reasonable costs, EPA considered the economic impact on the industry of these control techniques.

Cost-Effectiveness Considerations. EPA analyzed the annualized cost of controlling VOC emissions and the resultant VOC reduction for each alternative control technique. The control costs per megagram of VOC reduced for medium-sized process units are presented in Table 1 for each equipment type covered by the standards. These costs do not represent the actual amounts of money spent at any particular plant site. The cost of VOC emission reduction systems will vary according to the chemical product being produced, production equipment, plant layout, geographic location, and company preferences and policies. However, these costs and emission reductions are considered typical of control techniques for leaking equipment within SOCMI units and can be used in selecting the level of control to be required by the standards.

Pressure Relief Devices. The annualized costs and VOC emission reductions achieved for monthly and quarterly leak detection and repair programs and for the use of control equipment (rupture disks) were determined for pressure relief devices in gas service. As Table 1 shows, both the quarterly and monthly leak detection and repair programs are less expensive than installation of rupture disks.

TABLE 1.—CONTROL COSTS PER MEGAGRAM OF VOC REDUCED [a]

Equipment type and control technique [b]	Emission reduction (Mg/yr)	Average $/Mg [c]	Incremental $/Mg [d]
Pressure relief devices:			
Quarterly leak detection and repair	4.4	[f]	
Monthly leak detection and repair	5.1	[f]	300
Rupture disks [e]	10.0	510	1,200
Compressors: *Controlled degassing vents* [g]	4.6	[f]	[f]
Open-ended lines: *Caps on open-ended lines* [h]	0.2	480	480
Sampling Systems: *Closed purge sampling* [i]	3.4	580	580
Valves:			
Semi-annual leak detection and repair	17.1	[f]	
Quarterly repair leak detection and repair	28.9	[f]	[f]
Monthly leak detection and repair [j]	33.8	62	480
Pumps:			
Quarterly leak detection and repair	4.9	1,200	
Monthly leak detection and repair [k]	7.8	670	[f]

TABLE 1.—CONTROL COSTS PER MEGAGRAM OF VOC REDUCED [a]—Continued

Equipment type and control technique [b]	Emission reduction (Mg/yr)	Average $/Mg [c]	Incremental $/Mg [d]
Dual mechanical seal systems vented to a flare	12.6	2,300	5,600

[a] Costs and emission reductions based on equipment counts in Model Unit B. See Section 3.2 of the BID for the promulgated standards.
[b] Further discussion of control techniques can be found in Section 4 of the BID for the promulgated standards.
[c] Average dollars per megagram (cost effectiveness) = (net annualized cost per component) ÷ (annual VOC emission reduction per component).
[d] Incremental dollars per megagram = (net annualized cost of the control technique) − net annualized cost of the next less restrictive control technique ÷ (annual emission reduction of control technique − annual emission reduction of the next less restrictive control technique).
[e] Values are savings with the total savings indicated in the text.
[f] Control technique selected as the basis for the standard.

Leak detection and repair programs result in average credits of $240/Mg and $150/Mg of VOC for quarterly and monthly programs, respectively. A monthly leak detection and repair program achieves an additional 0.7 Mg/yr emission reduction for medium-sized process units at an incremental cost of $500/Mg compared to a quarterly leak detection and repair program. Rupture disks achieve an additional 4.9 Mg/yr emission reduction at an incremental cost of $1,200/Mg compared to a monthly leak detection and repair program. However, EPA is establishing a performance standard (as indicated by no detectable emission limit) allowing a variety of alternative ways to complying with the standard. Because EPA used conservative assumptions in making this incremental cost calculation, the $1,200/Mg incremental cost of achieving this 4.9 Mg/yr of emission reduction is more than what many process units would experience. Thus, a no detectable emission limit was selected as the basis for the pressure relief device standard.

Compressors. Only one control technique can be considered for compressor seals: the installation of control equipment such as barrier fluid systems. If a compressor is found leaking, the repair procedure would be the installation of control equipment. Because compressors are not generally spared, repair would be delayed until the next turnaround, thereby reducing the effectiveness of a leak detection and repair program to essentially zero. The installation of control equipment results in a savings ($100/Mg of VOC), indicating that the the value of product retained by controlling the barrier fluid system exceeds the cost of the control equipment. This cost is reasonable and, therefore, control equipment was selected as the basis for the standard for compressors.

Open-ended Lines and Sampling Systems. EPA considered caps or closures as the control technique for open-ended lines. Caps and closures are in wide-spread use in SOCMI and are expected to be used even more frequently in new SOCMI units. The cost and emission reduction presented in Table 1 are the cost and emission reduction which would be realized for an open-ended line that is not controlled. The $400/Mg cost for controlling emissions of VOC from open-ended lines is reasonable.

EPA considered closed purge sampling as the control technique for sampling systems. Closed purge systems are becoming increasingly common in the chemical industry. The $590/Mg cost for controlling emissions of VOC from sampling systems is reasonable.

Valve. Several leak detection and repair programs were considered for valves. The programs differed in the monitoring frequency which would be implemented. As Table 1 shows, the quarterly monitoring program results in savings ($41/Mg of VOC on the average). This occurs because the value of the recovered VOC is greater than the cost to implement the quarterly monitoring program. However, the largest emission reduction is associated with the monthly program at an average cost of $62/Mg. Furthermore, the incremental cost per Mg VOC emissions reduced for the monthly program is $510/Mg with an incremental emission reduction of 6.7 Mg/yr for a medium-sized process unit. EPA considers these costs to be reasonable. Therefore, EPA selected a monthly leak detection and repair program as the basis for the standard for valves.

Pumps. The control costs incurred for each megagram of VOC emissions reduced were determined for two leak detection and repair programs and for the use of dual mechanical seals with controlled degassing vents. Both leak detection and repair programs incur lower costs than the costs which would be incurred with equipment installation. The lowest average and incremental costs per Mg are associated with a monthly leak detection and repair program. The monthly program achieves a higher degree of control than the quarterly program, but it achieves a lower degree of control than installation of contol equipment. However, even though control equipment provides for the greatest amount of VOC reduction, the $5,600/Mg incremental costs to obtain the additional 5 Mg/yr are judged to be unreasonably high. Because the costs for equipment are unreasonably high, monthly leak detection and repair was selected as the basis for the standard for pumps.

Economic Impact Considerations. An economic analysis was performed which evaluated the economic impacts of the selected standards. The results of that analysis are presented in detail in the BID for the promulgated standards. As summarized in the Summary of the Impacts of the Standards section of this preamble, the industry-wide net annualized cost will be about $14.6 million in 1985. This cost is not expected to result in industry-wide price increases. These impacts are reasonable.

Control Technology—Use of Flares

Comment: Several commenters expressed the desire to use flares as alternatives to enclosed incinerators or vapor recovery systems. The comments focused on: (1) Data base support of low flare efficiency, (2) high efficiencies reported for flares on refinery gases, (3) alternative flare designs for low flow applications, (4) safety considerations in choosing control systems, and (5) equivalency to other combustion devices.

Response: The control technology for controlling equipment leaks of VOC from SOCMI is discussed in the background information documents (BID's) for the proposed standards and for the promulgated standards. [See ADDRESSES section of this preamble.] In the BID for the proposed standards, EPA discussed the control technology that can be used in complying with the standards. As discussed in the BID for the promulgated standards, EPA reviewed the comments received on the control technology for controlling equipment leaks and found nothing which would alter the original judgments concerning these control techniques except with regard to the control efficiency associated with flares used in SOCMI.

The use of flares was reconsidered by EPA. Flares are used widely in SOCMI for handling emergency releases from process units and for combusting streams from continuous vents. Since the flare efficiency estimate at proposal was made, further actual flare measurement results have become available, most notably from the Chemical Manufacturers Association

(CMA)–EPA study. In the CMA–EPA study, flares were investigated over a wide range of exit velocity, composition, and flare gas heat content conditions. After review of available flare efficiency data, EPA has concluded that smokeless flares designed for and operated under certain conditions are acceptable alternatives to enclosed combustion devices (incinerators, boilers, process heaters) or vapor recovery systems, such as carbon adsorbers and condensation units. For example, steam-assisted flares must have flare gas heat contents greater than 11.2 megajoules per standard cubic meter and exit velocities less than 18 meters per second. Flares achieving these conditions are acceptable because they achieve more than 98 percent emission reduction. The presence of a flame can be ensured by monitoring the flare's pilot light with an appropriate heat sensor, such as a thermocouple. To ensure smokeless operation, visible emissions from a flare would be limited to less than 5 minutes in any 2-hour period as determined by Reference Method 22.

Impact on Small Manufacturers

Comment: Commenters requested an exemption for small manufacturers. These commenters were mostly concerned with the impact on process units with few equipment and process units with low production volumes.

Response: Data from test work on equipment leaks of VOC, however, do not show any definite relationship between emissions and production volume. Equipment leaks of VOC and the cost of their control are proportional to the number of equipment components in a plant rather than the plant size or production volume. However, there are some process units (e.g., research and development facilities) which have production rates so small that their VOC emissions from equipment leaks are likely to be very small and, as a consequence, the cost to control these emissions would be unreasonably high. EPA has excluded from the standards process units producing less than 1,000 Mg/yr. The lower production rate cutoff was developed on the basis of cost and emission reduction considerations and is explained in Section 5.7 of the BID for the promul gated standards.

Test Method and Monitoring

Comment: Commenters requested that hexane be the required calibration gas for the application of Reference Method 21 to SOCMI leak detection and repair programs. Reference Method 21 specifies the monitor and the methodology to be used to detect leaks for required leak detection and repair programs. The proposed standards required that methane be used as the calibration gas. Two reasons were given for their desire to use hexane. First, commenters believed (on the basis of response factors) that the use of methane would result in the detection of more leaks. Second, there is at least one type of portable VOC detector which responds to hexane but does not respond to methane.

Response: EPA considered the differences between leak frequencies found using hexane and leak frequencies found using methane. The differences are not significant. The variability seen in repeat sampling of the same piece of equipment was 23 percent. The variability is in the same range as the 30 percent difference seen in response between the TLV-hexane system and the OVA-methane systems at the 10,000 ppmv definition of a leak. Because the variability in repeat sampling is similar to the differences in response at 10,000 ppmv, the data can be used interchangeably within 30 percent at the action level. Because an error of 30 percent at the action level is a small error considering all the errors associated with leak detection, there is no need to change the required calibration gas on the basis offered by the commenters. However, since some types of analyzers may be useful in certain SOCMI process units, and these types do not respond to methane, hexane has been added to the regulation as an alternate calibration material.

The use of hexane as an alternate calibration material is not limited to a single type of detector. The owner or operator may choose to use either calibrant with any allowable instrument. However, in any performance test conducted by EPA or a State agency, the VOC detector is likely to be calibrated with methane, even if the calibrant selected by the owner or operator is different, because methane calibrants are easier to obtain and deteriorate less than hexane calibrants.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking process. The docketing system is intended to allow members of the public and industries involved to identify and locate documents so that they can participate effectively in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review, except for interagency review materials [Section 307(d)(7)(A)].

Miscellaneous

In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to insure that cost was carefully considered in determining the best demonstrated technology. The economic impact assessment is included in the background information documents for the proposed standards and the promulgated standards.

Information collection requirements associated with this regulation (those included in 40 CFR Part 60, Subpart A and Subpart VV) have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060–0012.

"Major Rule" Determination. Under Executive Order 12291, the Administrator is required to judge whether a regulation is a "major rule" and, therefore, subject to certain requirements of the Order. The Administrator has determined that this regulation would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." Fifth-year annualized costs of the standards would be as much as $3.3 million for the 830 newly constructed, modified, and reconstructed production facilities projected that could be affected by the standards during the first 5 years. Significant price increases are not expected to result from

implementation of these standards because the annualized cost is a small fraction (about 0.25 percent) of the yearly revenue expected for the new, modified, and reconstructed units affected during the 5-year period. The Administrator has concluded that this rule is not "major" under any of the criteria established in the Executive Order.

As discussed in the "Basis For The Final Standards" section of this preamble, costs per megagram of VOC emission reduction were used in selecting the standards promulgated by this rulemaking. This regulation was submitted to the OMB for review as required by Executive Order 12291. Any comments from OMB to EPA and any EPA responses to those comments are available for public inspection in Docket No. A-79-32, Central Docket Section, at the address given in the **ADDRESSES** section of this preamble.

Regulatory Flexibility Analysis Certification. The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to current Small Business Administration guidelines, a small business in the organic chemical manufacturing industry is one that has 1,000 employees or fewer. Current estimates indicate between 10 and 30 percent of the existing industry employ fewer than 1,000 people. Even if facilities owned by small businesses do become subject to the standards, none will be adversely affected. This conclusion is based on the finding that the annualized cost of the standards would be less than 0.25 percent of the yearly revenue expected for units affected by the standards. This finding reflects the economic impact for facilities owned by small businesses and is not considered significant. Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic Minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel, Sulfuric acid plants, Waste treatment and disposal, Zinc, Tires, Incorporation by Reference, Can surface coating, Sulfuric acid plants, Industrial organic chemicals.

Dated: September 30, 1983.

William D. Ruckelshaus,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended as follows:

1. By adding paragraph (f) to § 60.7 of Subpart A—General Provisions as follows:

§ 60.7 Notification and recordkeeping.

* * * * *

(f) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

(Sec. 111, 114, 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411) 7601(a)))

2. By adding paragraph (f) to § 60.11 of Subpart A—General Provisions as follows:

§ 60.11 Compliance with standards and maintenance requirements.

* * * * *

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(Sec. 111, 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)))

3. By adding paragraphs (a)(34), (a)(35), (a)(36), (a)(37), (a)(38), and (a)(39) to § 60.17 of Subpart A—General Provisions as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(34) ASTM, E169-63 (Reapproved 1977), General Techniques of Ultraviolet Quantitative Analysis, IBR approved for § 60.485(d).

(35) ASTM E168-67 (Reapproved 1977), General Techniques of Infrared Quantitative Analysis, IBR approved for § 60.485(d).

(36) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for § 60.485(d).

(37) ASTM D2879-70, Vapor Pressure—Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for § 60.485(e).

(38) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for § 60.485(g).

(39) ASTM D2504-67 (Reapproved 1977), Noncondensable Gases in C_3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for § 60.485(g).

(Sec. 111, 114, 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411) 7601(a)))

4. By adding a new Subpart VV as follows:

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Sec.

60.480 Applicability and designation of affected facility.
60.481 Definitions.
60.482-1 Standards: General.
60.482-2 Standards: Pumps in light liquid service.
60.482-3 Standards: Compressors.
60.482-4 Standards: Pressure relief devices in gas/vapor service.
60.482-5 Standards: Sampling connection systems.
60.482-6 Standards: Open-ended valves or lines.
60.482-7 Standards: Valves in gas/vapor and in light liquid service.
60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.
60.482-9 Standards: Delay of repair.
60.482-10 Standards: Closed vent systems and control devices.
60.483-1 Alternative standards for valves—allowable percentage of valves leaking.
60.483-2 Alternative standards for valves—skip period leak detection and repair.
60.484 Equivalence of means of emission limitation.
60.485 Test methods and procedures.
60.486 Recordkeeping requirements.
60.487 Reporting requirements.
60.488 [Reserved]
60.489 List of chemicals produced by affected facilities.

Authority: Sec. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

§ 60.480 Applicability and designation of affected facility.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction or modification after January 5, 1981, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one of one of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486(h).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr is exempt from § 60.482.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from § 60.482.

(4) Any affected facility that produces beverage alcohol is exempt from § 60.482.

(5) Any affected facility that has no equipment in VOC service is exempt from § 60.482.

§ 60.481 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in Subpart A of Part 60, and the following terms shall have the specific meanings given them.

"Closed vent system" means a system that is not open to the atmosphere and that is composed of piping, connections, and, if necessary, flow inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device.

"Connector" means flanged, screwed, welded, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment.

"Control device" means an enclosed combustion device, vapor recovery system, or flare.

"Distance piece" means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

"Equipment" means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

"First attempt at repair" means to take rapid action for the purpose of stopping or reducing leakage of organic material to atmosphere using best practices.

"In gas/vapor service" means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

"In heavy liquid service" means that the piece of equipment is not in gas/vapor service or in light liquid service.

"In light liquid service" means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485(e).

"Liquids dripping" means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

"Open-ended valve or line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

"Pressure release" means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

"Process improvement" means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

"Process unit" means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

"Process unit shutdown" means a work practice or operational procedure that stops production from a process unit or part of a process unit. An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours is not a process unit shutdown. The use of spare equipment and technically feasible bypassing of equipment without stopping production are not process unit shutdowns.

"Quarter" means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

"Repaired" means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as indicated by one of the following: an instrument reading or 10,000 ppm or greater, indication of liquids dripping, or indication by a sensor that a seal or barrier fluid system has failed.

"Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

"In-situ sampling systems" means nonextractive samplers or in-line samplers.

"Synthetic organic chemicals manufacturing industry" means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

"In vacuum service" means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) below ambient pressure.

"Volatile organic compounds" or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

"In VOC Service" means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485(d) specify how to determine that a piece of equipment is not in VOC service.)

§ 60.482-1 Standards: General.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of § 60.482-1 to § 60.482-10 for all equipment within 180 days of initial startup.

(b) Compliance with § 60.482-1 to § 60.482-10 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of § 60.482-2, -3, -5, -6, -7, -8, and -10 as provided in § 60.484.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of § 60.482-2, -3, -5, -6, -7, -8, or -10, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of § 60.482-2 to § 60.482-10 if it is identified as required in § 60.486(e)(4).

§ 60.482-2 Standards: Pumps in light liquid service.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485(b), except as provided in § 60.482-1(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(2) If there are indications of liquids dripping from the pump seal, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a), provided the following requirements are met:

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipment with a barrier fluid degassing reservoir that is connected by a closed vent system to a control device that complies with the requirements of § 60.482–10; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm, and

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(6)(i) If there are indications of liquids dripping from the pump seal or the sensor indicates failure of the seal system, the barrier fluid system, or both based on the criterion determined in paragraph (d)(5)(ii), a leak is detected.

(ii) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9.

(iii) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) Any pump that is designated, as described in § 60.486(e) (1) and (2), for no detectable emission, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) if the pump:

(1) Has no externally actuated shaft penetrating the pump housing.

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (e)(2) initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a control device that complies with the requirements of § 60.482–10, it is exempt from the paragraphs (a)–(e).

§ 60.482–3 Compressors.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482–1(c) and paragraph (h) and (i) of this section.

(b) Each compressor seal system as required in paragraph (a) shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system that is connected by a closed vent system to a control device that complies with the requirements of § 60.482–10; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2), a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b), if it is equipped with a closed vent system capable of capturing and transporting any leakage from the seal to a control device that complies with the requirements of § 60.482–10, except as provided in § 60.482–3(i).

(i) Any compressor that is designated, as described in § 60.486(e) (1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a)–(h) if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485(c); and

(2) Is tested for compliance with paragraph (i)(1) initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or 60.15 is exempt from § 60.482 (a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of § 60.4823 (a), (b), (c), (d), (e), and (h).

§ 60.482–4 Standards: Pressure relief devices in gas/vapor service.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482–9.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485(c).

(c) Any pressure relief device that is equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482–10 is exempted from the requirements of paragraphs (a) and (b).

§ 60.482-5 Standards: Sampling connection systems.

(a) Each sampling connection system shall be equipped with a closed purge system or closed vent system, except as provided in § 60.482-1(c).

(b) Each closed purge system or closed vent system as required in paragraph (a) shall:

(1) Return the purged process fluid directly to the process line with zero VOC emissions to the atmosphere; or

(2) Collect and recycle the purged process fluid with zero VOC emissions to the atmosphere; or

(3) Be designed and operated to capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482-10.

(c) In-situ sampling systems are exempt from paragraphs (a) and (b).

§ 60.482-6 Standards: Open-ended valves or lines.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482-1(c).

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

§ 60.482-7 Standards: Valves in gas/vapor service in light liquid service.

(a) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485(b) and shall comply with paragraphs (b)-(e), except as provided in paragraphs (f), (g), and (h), § 60.483-1, 2, and § 60.482-1(c).

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(2) If a leak is detected, the valve shall be monitored monthly until a lead is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482-9.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485(c), and

(3) Is tested for compliance with paragraph (f)(2) initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a), and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located becomes an affected facility through § 60.14 or § 60.15, and

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors.

(a) Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall be monitored within 5 days by the method specified in § 60.485(b) if evidence of a potential leak is found by visual, audible, olfactory, or any other detection method.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482-9.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under § 60.482-7(e).

§ 60.482-9 Standards: Delay of repair.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if the repair is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482-10.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

§ 60.482-10 Standards: Closed vent systems and control devices.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart

shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816°C.

(d)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in § 60.485(g), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in § 60.485(g).

(3) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in § 60.485(g).

(4) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in § 60.485(g)(4), less than 18 m/sec (60 ft/sec).

(5) Flares used to comply with this subpart shall be steam-assisted, air-assisted, or nonassisted.

(6) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the methods specified in § 60.485(g)(5).

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f)(1) Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined by the methods specified in § 60.485(c).

(2) Closed vent systems shall be monitored to determine compliance with this section initially in accordance with § 60.8, annually and at other times requested by the Administrator.

(g) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.483-1 Alternative standards for valves—allowable percentage of valves leaking.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487(b).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482-7(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485(b).

(2) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent.

§ 60.483-2 Alternative standards for valves—skip period leak detection and repair.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b) (2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(b).

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482-7.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482-7 but can again elect to use this section.

(5) The percent of valves leaking shall be determined by dividing the sum of valves found leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements of § 60.483-2.

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

§ 60.484 Equivalence of means of emission limitation.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalance for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate

equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4).

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the Federal Register and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the Federal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of Section 111(h)(1) of the Clean Air Act.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e).

§ 60.485 Test methods and procedures.

(a) Each owner or operator subject to the provisions of this subpart shall comply with the test method and procedure requirements provided in this section.

(b) Monitoring, as required in §§ 60.482, 60.483, and 60.484, shall comply with the following requirements:

(1) Monitoring shall comply with Reference Method 21.

(2) The detection instrument shall meet the performance criteria of Reference Method 21.

(3) The instrument shall be calibrated before use on each day of its use by the methods specified in Method 21.

(4) Calibration gases shall be:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

(5) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(c) When equipment is tested for compliance with no detectable emissions as required in § 60.482–2(e), –3(i), –4, –7(f), and –10(e), the test shall comply with the following requirements:

(1) The requirements of paragraphs (b)(1)–(4) shall apply.

(2) The background level shall be determined, as set forth in Reference Method 21.

(3) The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Reference Method 21.

(4) The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d)(1) Each piece of equipment within a process unit is presumed to be in VOC service unless an owner or operator demonstrates that the piece of equipment is not in VOC service. For a piece of equipment to be considered not in VOC service, it must be determined that the percent VOC content can be reasonably expected never to exceed 10 percent by weight. For purposes of determining the percent VOC content in the process fluid that is contained in or contacts equipment, procedures that conform to the general methods described in ASTM E–260, E–168, E–169 (incorporated by reference as specified in § 60.17) shall be used.

(2) If an owner or operator decides to exclude non-reactive organic compounds from the total quantity of organic compounds in determining the percent VOC content of the process fluid, the exclusion will be allowed if:

(i) Those substances excluded are those considered as having negligible photochemical reactivity by the Administrator; and

(ii) The owner or operator demonstrates that the percent organic content, excluding non-reactive organic compounds, can be reasonably expected never to exceed 10 percent by weight.

(3)(i) An owner or operator may use engineering judgment rather than the procedures in paragraphs (d) (1) and (2) of this section to demonstrate that the percent VOC content does not exceed 10 percent by weight, provided that the engineering judgment demonstrates that the VOC content clearly does not exceed 10 percent by weight. When an owner or operator and the Administrator do not agree on whether a piece of equipment is not in VOC service, however, the procedures in paragraphs (d) (1) and (2) shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in VOC service, the determination can be revised only after following the procedures in paragraphs (d) (1) and (2).

(e) Equipment is in light liquid service if the following conditions apply:

(1) The vapor pressure of one or more of the components is greater than 0.3 kPa at 20° C. Vapor pressures may be obtained from standard reference texts or may be determined by ASTM D–2879 (incorporated by reference as specified in § 60.17).

(2) The total concentration of the pure components having a vapor pressure greater than 0.3 kPa at 20° C is equal to or greater than 20 percent by weight; and

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g)(1) Reference Method 22 shall be used to determine the compliance of flares with the visible emission provisions of this subpart.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K\left(\frac{n}{\sum_{i=1} C_i H_i}\right)$$

Where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°.

$$K = \text{Constant, } 1.740 \times 10^{7} \left(\frac{1}{\text{ppm}}\right)\left(\frac{\text{g mole}}{\text{scm}}\right)\left(\frac{\text{MJ}}{\text{kcal.}}\right)$$

where

$$\text{standard temperature for } \frac{\text{g mole}}{\text{scm}} \text{ is } 20°\text{C.}$$

C_i = Concentration of sample component i in ppm, as measured by Reference Method 18 and ASTM D2504–67 (reapproved 1977) (incorporated by reference as specified in § 60.17).

H_i = Net heat of combustion of sample component i, kcal/g mole. The heats of combustion may be determined using ASTM D2382–76 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Method 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation:

$$V_{max} = 8.706 + 0.7084(H_T)$$

V_{max} = Maximum permitted velocity, m/sec.

8.706 = Constant.

0.7084 = Constant.

H_T = The net heating value as determined in paragraph (g)(4).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.486 Recordkeeping requirements.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(b) When each leak is detected as specified in § 60.482–2, -3, -7, -8, and § 60.483–2, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482–7(c) and no leak has been detected during those 2 months.

(3) The identification on equipment except on a valve, may be removed after it has been repaired.

(c) When each leak is detected as specified in § 60.482–2, -3, -7, -8, and § 60.483–2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) "Above 10.000" if the maximum instrument reading measured by the methods specified in § 60.485(a) after each repair attempt is equal to or greater than 10,000 ppm.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdown that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482–10 shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482–10(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in § 60.482–2, -3, -4, and -5 are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in § 60.482–2, -3, -4, and -5.

(e) The following information pertaining to all equipment subject to the requirements in § 60.482–1 to -10 shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–2(e), -3(i) and -7(f).

(ii) The designation of equipment as subject to the requirements of § 60.482–2(e), -3(i), or -7(f) shall be signed by the owner or operator.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482–4.

(4)(i) The dates of each compliance test as required in § 60.482–2(e), -3(i), -4, and -7(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacum service.

(f) The following information pertaining to all valves subject to the requirements of § 60.482–7 (g) and (h) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves that are designated as unsafe-to-monitor, an explanation for each valve stating why the valve is unsafe-to-monitor, and the plan for monitoring each valve.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each value.

(g) The following information shall be recorded for valves complying with § 60.483–2:

(1) A schedule of monitoring

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in § 60.482-2(d)(5) and § 60.482-3(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §§ 60.7 (b) and (d) do not apply to affected facilities subject to this subpart.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

(Approved by the Office of Management and Budget under the control number 2060-0012)

§ 60.487 Reporting Requirements.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning six months after the initial start up date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482-7, excluding those valves designated for no detectable emissions under the provisions of § 60.482-7(f).

(3) Number of pumps subject to the requirements of § 60.482-2, excluding those pumps designated for no detectable emissions under the provisions of § 60.482-2(e) and those pumps complying with § 60.482-2(f).

(4) Number of compressors subject to the requirements of § 60.482-3, excluding those compressors designated for no detectable emissions under the provisions of § 60.482-3(i) and those compressors complying with § 60.482-3(h).

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482(7)(b) or § 60.483-2,

(ii) Number of valves for which leaks were not reported as required in § 60.482-7(d)(1),

(iii) Number of pumps for which leaks were detected as described in §§ 60.482-2(b) and (d)(6)(i),

(iv) Number of pumps for which leaks erer not repaired as required in §§ 60.482-2(c)(1) and (d)(6)(ii),

(v) Number of compressors for which leaks were detected as desctibed in § 60.482-3(f),

(vi) Number of compressors for which leaks were not reported as required in § 60.482-3(g)(1), and

(vii) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or opertor electing to comply with the provisions of §§ 60.483-1 and -2 shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this subsection remain in force until and unless EPA, in delegating enforcement authority to a State under Section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this subsection, provided that they comply with the requirements established by the State.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

Approved by the Office of Management and Budget under the control number 2060-0012)

§ 60.488 [Reserved]

§ 60.489 List of chemicals produced by affected facilities.

(a) The following chemicals are produced, as intermediates or final products, by process units covered under this subpart. The applicability date for process units producing one or more of these chemicals is January 5, 1981.

CAS No. *	Chemical
105-57-7	Acetal.
75-07-0	Acetaldehyde.
107-89-1	Acetaldol.
60-35-5	Acetamide.
103-84-4	Acetanilide.
64-19-7	Acetic acid.
108-24-7	Acetic anhydride.
67-64-1	Acetone.
75-86-5	Acetone cyanohydrin.
75-05-8	Acetonitrile.
98-86-2	Acetophenone.
75-36-5	Acetyl chloride.
74-86-2	Acetylene.
107-02-8	Acrolein.
79-06-1	Acrylamide.
79-10-7	Acrylic acid.
107-13-1	Acrylonitrile.
124-04-9	Adipic acid.
111-69-3	Adiponitrile.
(*)	Alkyl naphthalenes.
107-18-6	Allyl alcohol.
107-05-1	Allyl chloride.
1321-11-5	Aminobenzoic acid.
111-41-1	Aminoethylethanolamine.
123-30-8	p-Aminophenol.
626-63-7, 123-92-2	Amyl acetates.
71-41-0 *	Amyl alcohols.
110-58-7	Amyl amine.
543-59-9	Amyl chloride.
110-66-7 *	Amyl mercaptans.
1322-06-1	Amyl phenol.
62-53-3	Aniline.
142-04-1	Aniline hydrochloride.
29191-52-4	Anisidine.
100-66-3	Anisole.
118-92-3	Anthranilic acid.
84-65-1	Anthraquinone.
100-52-7	Benzaldehyde.
55-21-0	Benzamide.
71-43-2	Benzene.
98-48-6	Benzenedisulfonic acid.
98-11-3	Benzenesulfonic acid.
134-81-6	Benzil.
76-93-7	Benzilic acid.
65-85-0	Benzoic acid.
119-53-9	Benzoin.
100-47-0	Benzonitrile.
119-61-9	Benzophenone.
98-07-7	Benzotrichloride.
98-88-4	Benzoyl chloride.
100-51-6	Benzyl alcohol.
100-46-9	Benzylamine.
120-51-4	Benzyl benzoate.
100-44-7	Benzyl chloride.
98-87-3	Benzyl dichloride.
92-52-4	Biphenyl.
80-05-7	Bisphenol A.
10-86-1	Bromobenzene.
27497-51-4	Bromonaphthalene.
106-99-0	Butadiene.
106-98-9	1-butene.
123-86-4	n-butyl acetate.
141-32-2	n-butyl acrylate.
71-36-3	n-butyl alcohol.
78-92-2	s-butyl alcohol.
75-65-0	t-butyl alcohol.
109-73-9	n-butylamine.
13952-84-6	s-butylamine.
75-64-9	t-butylamine.
98-73-7	p-tert-butyl benzoic acid.
107-88-0	1,3-butylene glycol.
123-72-8	n-butyraldehyde.
107-92-6	Butyric acid.
106-31-0	Butyric anhydride.
109-74-0	Butyronitrile.
105-60-2	Caprolactam.
75-1-50	Carbon disulfide.

CAS No. [a]	Chemical
558-13-4	Carbon tetrabromide.
56-23-5	Carbon tetrachloride.
9004-35-7	Cellulose acetate.
79-11-8	Chloroacetic acid.
108-42-9	m-chloroaniline.
95-51-2	o-chloroaniline.
106-47-8	p-chloroaniline.
35913-09-8	Chlorobenzaldehyde.
108-90-7	Chlorobenzene.
118-91-2, 535-80-8, 74-11-3 [c].	Chlorobenzoic acid.
2136-81-4, 2136-89-2, 5216-25-1 [c].	Chlorobenzotrichloride.
1321-03-5	Chlorobenzoyl chloride.
25497-29-4	Chlorodifluoromethane.
75-45-6	Chlorodifluoroethane.
67-66-3	Chloroform.
25586-43-0	Chloronaphthalene.
88-73-3	o-chloronitrobenzene.
100-00-5	p-chloronitrobenzene.
25167-80-0	Chlorophenols.
126-99-8	Chloroprene.
7790-94-5	Chlorosulfonic acid.
108-41-8	m-chlorotoluene.
95-49-8	o-chlorotoluene.
106-43-4	p-chlorotoluene.
75-72-9	Chlorotrifluoromethane.
108-39-4	m-cresol.
95-48-7	o-cresol.
106-44-5	p-cresol.
1319-77-3	Mixed cresols.
1319-77-3	Cresylic acid.
4170-30-0	Crotonaldehyde.
3724-65-0	Crotonic acid.
98-82-8	Cumene.
80-15-9	Cumene hydroperoxide.
372-09-8	Cyanoacetic acid.
506-77-4	Cyanogen chloride.
108-80-5	Cyanuric acid.
108-77-0	Cyanuric chloride.
110-82-7	Cyclohexane.
108-93-0	Cyclohexanol.
108-94-1	Cyclohexanone.
110-83-8	Cyclohexene.
108-91-8	Cyclohexylamine.
111-78-4	Cyclooctadiene.
112-30-1	Decanol.
123-42-2	Diacetone alcohol.
27576-04-1	Diaminobenzoic acid.
95-76-1, 95-82-9, 554-00-7, 608-27-5, 608-31-1, 626-43-7, 27134-27-6, 57311-92-9 [c].	Dichloroaniline.
541-73-1	m-dichlorobenzene.
95-50-1	o-dichlorobenzene.
106-46-7	p-dichlorobenzene.
75-71-8	Dichlorodifluoromethane.
111-44-4	Dichloroethyl ether.
107-06-2	1,2-dichloroethane (EDC).
96-23-1	Dichlorohydrin.
26952-23-8	Dichloropropene.
101-83-7	Dicyclohexylamine.
109-89-7	Diethylamine.
111-46-6	Diethylene glycol.
112-36-7	Diethylene glycol diethyl ether.
111-96-6	Diethylene glycol dimethyl ether.
112-34-5	Diethylene glycol monobutyl ether.
124-17-7	Diethylene glycol monobutyl ether acetate.
111-90-0	Diethylene glycol monoethyl ether.
112-15-2	Diethylene glycol monoethyl ether acetate.
111-77-3	Diethylene glycol monomethyl ether.
64-67-5	Diethyl sulfate.
75-37-6	Difluoroethane.
25167-70-8	Diisobutylene.
26761-40-0	Diisodecyl phthalate.
27554-26-3	Diisooctyl phthalate.
674-82-8	Diketene.
124-40-3	Dimethylamine.
121-69-7	N,N-dimethylaniline.
115-10-6	N,N-dimethyl ether.
68-12-2	N,N-dimethylformamide.
57-14-7	Dimethylhydrazine.
77-78-1	Dimethyl sulfate.
75-18-3	Dimethyl sulfide.
67-68-5	Dimethyl sulfoxide.
120-61-6	Dimethyl terephthalate.
99-34-3	3,5-dinitrobenzoic acid.

CAS No. [a]	Chemical
51-28-5	Dinitrophenol.
25321-14-6	Dinitrotoluene.
123-91-1	Dioxane.
646-06-0	Dioxolane.
122-39-4	Diphenylamine.
101-84-8	Diphenyl oxide.
102-08-9	Diphenyl thiourea.
25265-71-8	Dipropylene glycol.
25378-22-7	Dodecene.
28675-17-4	Dodecylaniline.
27193-86-8	Dodecylphenol.
106-89-8	Epichlorohydrin.
64-17-5	Ethanol.
141-43-5 [c]	Ethanolamines.
141-78-6	Ethyl acetate.
141-97-9	Ethyl acetoacetate.
140-88-5	Ethyl acrylate.
75-04-7	Ethylamine.
100-41-4	Ethylbenzene.
74-96-4	Ethyl bromide.
9004-57-3	Ethylcellulose.
75-00-3	Ethyl chloride.
105-39-5	Ethyl chloroacetate.
105-56-6	Ethylcyanoacetate.
74-85-1	Ethylene.
96-49-1	Ethylene carbonate.
107-07-3	Ethylene chlorohydrin.
107-15-3	Ethylenediamine.
106-93-4	Ethylene dibromide.
107-21-1	Ethylene glycol.
111-55-7	Ethylene glycol diacetate.
110-71-4	Ethylene glycol dimethyl ether.
111-76-2	Ethylene glycol monobutyl ether.
112-07-2	Ethylene glycol monobutyl ether acetate.
110-80-5	Ethylene glycol monoethy ether.
111-15-9	Ethylene glycol monethyl ether acetate.
109-86-4	Ethylene glycol monomethyl ether.
110-49-6	Ethylene glycol monomethyl ether acetate.
122-99-6	Ethylene glycol monophenyl ether.
2807-30-9	Ethylene glycol monopropyl ether.
75-21-8	Ethylene oxide.
60-29-7	Ethyl ether
104-76-7	2-ethylhexanol.
122-51-0	Ethyl orthoformate.
95-92-1	Ethyl oxalate.
41892-71-1	Ethyl sodium oxalacetate.
50-00-0	Formaldehyde.
75-12-7	Formamide.
64-18-6	Formic acid.
110-17-8	Fumaric acid.
98-01-1	Furfural.
56-81-5	Glycerol.
26545-73-7	Glycerol dichlorohydrin.
25791-96-2	Glycerol triether.
56-40-6	Glycine.
107-22-2	Glyoxal.
118-74-1	Hexachlorobenzene.
67-72-1	Hexachloroethane.
36653-82-4	Hexadecyl alcohol.
124-09-4	Hexamethylenediamine.
629-11-8	Hexamethylene glycol.
100-97-0	Hexamethylenetetramine.
74-90-8	Hydrogen cyanide.
123-31-9	Hydroquinone.
99-96-7	p-hydroxybenzoic acid.
26760-64-5	Isoamylene.
78-83-1	Isobutanol.
110-19-0	Isobutyl acetate.
115-11-7	Isobutylene.
78-84-2	Isobutyraldehyde.
79-31-2	Isobutyric acid.
25339-17-7	Isodecanol.
26952-21-6	Isooctyl alcohol.
78-78-4	Isopentane.
78-59-1	Isophorone.
121-91-5	Isophthalic acid.
78-79-5	Isoprene.
67-63-0	Isopropanol.
108-21-4	Isopropyl acetate.
75-31-0	Isopropylamine.
75-29-6	Isopropyl chloride.
25168-06-3	Isopropylphenol.
463-51-4	Ketene.
(*)	Linear alkyl sulfonate.
123-01-3	Linear alkylbenzene (linear dodecylbenzene).
110-16-7	Maleic acid.
108-31-6	Maleic anhydride.
6915-15-7	Malic acid.
141-79-7	Mesityl oxide.
121-47-1	Metanilic acid.
79-41-4	Methacrylic acid.
563-47-3	Methallyl chloride.

CAS No. [a]	Chemical
67-56-1	Methanol.
79-20-9	Methyl acetate.
105-45-3	Methyl acetoacetate.
74-89-5	Methylamine.
100-61-8	n-methylaniline.
74-83-9	Methyl bromide.
37365-71-2	Methyl butynol.
74-87-3	Methyl chloride.
108-87-2	Methylcyclohexane.
1331-22-2	Methylcyclohexanone.
75-09-2	Methylene chloride.
101-77-9	Methylene dianiline.
101-68-8	Methylene diphenyl diisocyanate.
78-93-3	Methyl ethyl ketone.
107-31-3	Methyl formate.
108-11-2	Methyl isobutyl carbinol.
108-10-1	Methyl isobutyl ketone.
80-62-6	Methyl methacrylate.
77-75-8	Methylpentynol.
98-83-9	a-methylstyrene.
110-91-8	Morpholine.
85-47-2	a-napthalene sulfonic acid.
120-18-3	b-napthalene sulfonic acid.
90-15-3	a-naphthol.
135-19-3	b-naphthol.
75-98-9	Neopentanoic acid.
88-74-4	o-nitroaniline.
100-01-6	p-nitroaniline.
91-23-6	o-nitroanisole.
100-17-4	p-nitroanisole.
98-95-3	Nitrobenzene.
27178-83-2 [c]	Nitrobenzoic acid (o,m, and p).
79-24-3	Nitroethane.
75-52-5	Nitromethane.
88-75-5	2-Nitrophenol.
25322-01-4	Nitropropane.
1321-12-6	Nitrotoluene.
27215-95-8	Nonene.
25154-52-3	Nonylphenol.
27193-28-8	Octylphenol.
123-63-7	Paraldehyde.
115-77-5	Pentaerythritol.
109-66-0	n-pentane.
109-67-1	1-pentene
127-18-4	Perchloroethylene.
594-42-3	Perchloromethyl mercaptan.
94-70-2	o-phenetidine.
156-43-4	p-phenetidine.
108-95-2	Phenol.
98-67-9, 585-38-6, 609-46-1, 1333-39-7 [c].	Phenolsulfonic acids.
91-40-7	Phenyl anthranilic acid.
(*)	Phenylenediamine.
75-44-5	Phosgene.
85-44-9	Phthalic anhydride.
85-41-6	Phthalimide.
108-99-6	b-picoline.
110-85-0	Piperazine.
9003-29-6, 25036-29-7 [c].	Polybutenes.
25322-68-3	Polyethylene glycol.
25322-69-4	Polypropylene glycol.
123-38-6	Propional dehyde.
79-09-4	Propionic acid.
71-23-8	n-propyl alcohol.
107-10-8	Propylamine.
540-54-5	Propyl chloride.
115-07-1	Propylene.
127-00-4	Propylene chlorohydrin.
78-87-5	Propylene dichloride.
57-55-6	Propylene glycol.
75-56-9	Propylene oxide.
110-86-1	Pyridine.
106-51-4	Quinone.
108-46-3	Resorcinol.
27138-57-4	Resorcylic acid.
69-72-7	Salicylic acid.
127-09-3	Sodium acetate.
532-32-1	Sodium benzoate.
9004-32-4	Sodium carboxymethyl cellulose.
3926-62-3	Sodium chloroacetate.
141-53-7	Sodium formate.
139-02-6	Sodium phenate.
110-44-1	Sorbic acid.
100-42-5	Styrene.
110-15-6	Succinic acid.
110-61-2	Succinonitrile.
121-57-3	Sulfanilic acid.
126-33-0	Sulfolane.
1401-55-4	Tannic acid.
100-21-0	Terephthalic acid.
79-34-5 [c]	Tetrachloroethanes.
117-08-8	Tetrachlorophthalic anhydride.

CAS No. [a]	Chemical
78-00-2	Tetraethyl lead.
119-64-2	Tetrahydronapthalene.
85-43-8	Tetrahydrophthalic anhydride.
75-74-1	Tetramethyl lead.
110-60-1	Tetramethylenediamine.
110-18-9	Tetramethylethylenediamine.
108-88-3	Toluene.
95-80-7	Toluene-2,4-diamine.
584-84-9	Toluene-2,4-diisocyanate.
26471-62-5	Toluene diisocyanates (mixture).
1333-07-9	Toluenesulfonamide.
104-15-4 [c]	Toluenesulfonic acids.
98-59-9	Toluenesulfonyl chloride.
26915-12-8	Toluidines.
87-61-6, 108-70-3, 120-82-1 [c]	Trichlorobenzenes.
71-55-6	1,1,1-trichloroethane. [b]
79-00-5	1,1,2-trichloroethane.
79-01-6	Trichloroethylene.
75-69-4	Trichlorofluoromethane.
96-18-4	1,2,3-trichloropropane.
76-13-1	1,1,2-trichloro-1,2,2-trifluoroethane.
121-44-8	Triethylamine.
112-27-6	Triethylene glycol.
112-49-2	Triethylene glycol dimethyl ether.
7756-94-7	Triisobutylene.
75-50-3	Trimethylamine.
57-13-6	Urea.
108-05-4	Vinyl acetate.
75-01-4	Vinyl chloride.
75-35-4	Vinylidene chloride.
25013-15-4	Vinyl toluene.
1330-20-7	Xylenes (mixed).
95-47-6	o-xylene.
106-42-3	p-xylene.
1300-71-6	Xylenol.
1300-73-8	Xylidine.

[a] CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[b] No CAS number(s) have been assigned to this chemical, its isomers, or mixtures containing these chemicals.

[c] CAS numbers for some of the isomers are listed; the standards apply to all of the isomers and mixtures, even if CAS numbers have not been assigned.

5. In Appendix A of Part 60, Method 18 is added as follows:

Method 18—Measurement of Gaseous Organic Compound Emissions by Gas Chromatography

Introduction

[This method should not be attempted by persons unfamiliar with the performance characteristics of gas chromatography, nor by those persons who are unfamiliar with source sampling. Particular care should be exercised in the area of safety concerning choice of equipment and operation in potentially explosive atmospheres.]

1. *Applicability and Principle*

1.1 Applicability. This method applies to the analysis of approximately 90 percent of the total gaseous organics emitted from an industrial source. It does not include techniques to identify and measure trace amounts of organic compounds, such as those found in building air and fugitive emission sources.

This method will not determine compounds that (1) are polymeric (high molecular weight), (2) can polymerize before analysis, or (3) have very low vapor pressures at stack or instrument conditions.

1.2 Principle. This method is based on separating the major components of a gas mixture with a gas chromatograph (GC) and measuring the separated components with a suitable detector.

The retention times of each separated component are compared with those of known compounds under identical conditions. Therefore, the analyst confirms the identity and approximate concentrations of the organic emission components beforehand. With this information, the analyst then prepares or purchases commercially available standard mixtures to calibrate the GC under conditions identical to those of the samples. The analyst also determines the need for sample dilution to avoid detector saturation, gas stream filtration to eliminate particulate matter, and prevention of moisture condensation.

2. *Range and Sensitivity*

2.1 Range. The range of this method is from about 1 part per million (ppm) to the upper limit governed by GC detector saturation or column overloading. The upper limit can be extended by diluting the stack gases with an inert gas or by using smaller gas sampling loops.

2.2 Sensitivity. The sensitivity limit for a compound is defined as the minimum detectable concentration of that compound, or the concentration that produces a signal-to-noise ratio of three to one. The minimum detectable concentration is determined during the presurvey calibration for each compound.

3. *Precision and Accuracy*

Gas chromatographic techniques typically provide a precision of 5 to 10 percent relative standard deviation (RSD), but an experienced GC operator with a reliable instrument can readily achieve 5 percent RSD. For this method, the following combined GC/operator values are required.

(a) Precision. Duplicate analyses are within 5 percent of their mean value.

(b) Accuracy. Analysis results of prepared audit samples are within 10 percent of preparation values.

4. *Interferences*

Resolution interferences that may occur can be eliminated by appropriate GC column and detector choice or by shifting the retention times through changes in the column flow rate and the use of temperature programming.

The analytical system is demonstrated to be essentially free from contaminants by periodically analyzing blanks that consist of hydrocarbon-free air or nitrogen.

Sample cross-contamination that occurs when high-level and low-level samples or standards are analyzed alternately, is best dealt with by thorough purging of the GC sample loop between samples.

To assure consistent detector response, calibration gases are contained in dry air. To eliminate errors in concentration calculations due to the volume of water vapor in the samples, moisture concentrations are determined for each sample, and a correction factor is applied to any sample with greater than 2 percent water vapor.

5. *Presurvey and Presurvey Sampling*

A presurvey shall be performed on each source to be tested. The purpose of the presurvey is to obtain all information necessary to design the emission test. The most important presurvey data are the average stack temperature and temperature range, approximate particulate concentration, static pressure, water vapor content, and identity and expected concentration of each organic compound to be analyzed. Some of this information can be obtained from literature surveys, direct knowledge, or plant personnel. However, presurvey samples of the gas shall be obtained for analysis to confirm the identity and approximate concentrations of the specific compounds prior to the final testing.

5.2 Apparatus.

5.1.1 Teflon Tubing. (Mention of trade names or specific products does not constitute endorsement by the U.S. Environmental Protection Agency.) Diameter and length determined by connection requirements of cylinder regulators and the GC. Additional tubing is necessary to connect the GC sample loop to the sample.

5.1.2 Gas Chromatograph. GC with suitable detector, columns, temperature-controlled sample loop and valve assembly, and temperature programable oven, if necessary. The GC shall achieve sensitivity requirements for the compounds under study.

5.1.3 Pump. Capable of pumping 100 ml/min. For flushing sample loop.

5.1.4 Flow Meter. To accurately monitor sample loop flow rate of 100 ml/min.

5.1.5 Regulators. Used on gas cylinders for GC and for cylinder standards.

5.1.6 Recorder. Recorder with linear strip chart is minimum acceptable. Integrator (optional) is recommended.

5.1.7 Syringes. 1.0- and 10-microliter size, calibrated, maximum accuracy (gas tight) for preparing standards and for injecting head space vapor from liquid standards in retention time studies.

5.1.8 Tubing Fittings. To plumb GC and gas cylinders.

5.1.9 Septums. For syringe injections.

5.1.10 Glass Jars. If necessary, clean-colored glass jars with Teflon-lined lids for condensate sample collection. Size depends on volume of condensate.

5.1.11 Soap Film Flow Meter. To determine flow rates.

5.1.12 Tedlar Bags. 10- and 50-liter capacity, for preparation of standards.

5.1.13 Dry Gas Meter with Temperature and Pressure Gauges. Accurate to ±2 percent, for perparation of gas standards.

5.1.14 Midget Impinger/Hot Plate Assembly. For preparation of gas standards.

5.1.15 Sample Flasks. For presurvey samples, must have gas-tight seals.

5.1.16 Adsorption Tubes. If necessary, blank tubes filled with necessary adsorbent (charcoal, Tenax, XAD-2, etc.) for presurvey samples.

5.1.17 Personnel Sampling Pump. Calibrated, for collecting adsorbent tube presurvey samples.

5.1.18 Dilution System. Calibrated, the dilution system is to be constructed following the specifications of an acceptable method.

5.2 Reagents.

5.2.1 Deionized Distilled Water.

5.2.2 Methylene Dichloride.

5.2.3 Calibration Gases. A series of standards prepared for every compound of interest.

5.2.4 Calibration Solutions. Samples of all the compounds of interest in a liquid form, for retention time studies.

5.2.5 Extraction Solvents. For extraction of adsorbent tube samples in preparation for analysis.

5.2.6 Fuel. As recommended by the manufacturer for operation of the GC.

5.2.7 Carrier Gas. Hydrocarbon free, as recommended by the manufacturer for operation of the detector and compatability with the column.

5.2.8 Zero Gas. Hydrocarbon free air or nitrogen, to be used for dilutions, blank preparation, and standard preparation.

5.3 Sampling.

5.3.1 Collection of Samples with Glass Sampling Flasks. Presurvey samples can be collected in precleaned 250-ml double-ended glass sampling flasks. Teflon stopcocks, without grease, are preferred. Flasks should be cleaned as follows: Remove the stopcocks from both ends of the flasks, and wipe the parts to remove any grease. Clean the stopcocks, barrels, and receivers with methylene dichloride. Clean all glass ports with a soap solution, then rinse with tap and deionized distilled water. Place the flask in a cool glass annealing furnace and apply heat up to 500° C. Maintain at this temperature for 1 hour. After this time period, shut off and open the furnace to allow the flask to cool. Grease the stopcocks with stopcock grease and return them to the flask receivers. Purge the assembly with high-purity nitrogen for 2 to 5 minutes. Close off the stopcocks after purging to maintain a slight positive nitrogen pressure. Secure the stopcocks with tape.

Presurvey samples can be obtained either by drawing the gases into the previously evacuated flask or by drawing the gases into and purging the flask with a rubber suction bulb.

5.3.1.1 Evacuated Flask Procedure. Use a high-vacuum pump to evacuate the flask to the capacity of the pump; then close off the stopcock leading to the pump. Attach a 6-mm outside diameter (OD) glass tee to the flask inlet with a short piece of Teflon tubing. Select a 6-mm OD borosilicate sampling probe, enlarged at one end to a 12-mm OD and of sufficient length to reach the centroid of the duct to be sampled. Insert a glass wool plug in the enlarged end of the probe to remove particulate matter. Attach the other end of the probe to the tee with a short piece of Teflon tubing. Connect a rubber suction bulb to the third leg of the tee. Place the filter end of the probe at the centroid of the duct, and purge the probe with the rubber suction bulb. After the probe is completely purged and filled with duct gases, open the stopcock to the grab flask until the pressure in the flask reaches duct pressure. Close off the stopcock, and remove the probe from the duct. Remove the tee from the flask and tape the stopcocks to prevent leaks during shipment. Measure and record the duct temperature and pressure.

5.3.1.2 Purged Flask Procedure. Attach one end of the sampling flask to a rubber suction bulb. Attach the other end to a 6-mm OD glass probe as described in Section 5.3.1.1. Place the filter end of the probe at the centroid of the duct, and apply suction with the bulb to completely purge the probe and flask. After the flask has been purged, close off the stopcock near the suction bulb, and then close the stopcock near the probe. Remove the probe from the duct, and disconnect both the probe and suction bulb. Tape the stopcocks to prevent leakage during shipment. Measure and record the duct temperature and pressure.

5.3.2 Flexible Bag Procedure. Tedlar or aluminized Mylar bags can also be used to obtain the presurvey sample. Use new bags, and leak check them before field use. In addition, check the bag before use for contamination by filling it with nitrogen or air, and analyzing the gas by GC at high sensitivity. Experience indicates that it is desirable to allow the inert gas to remain in the bag about 24 hours or longer to check for desorption of organics from the bag. Follow the leak check and sample collection procedures given in Section 7.1.

5.3.3 Determination of Moisture Content. For combustion or water-controlled processes, obtain the moisture content from plant personnel or by measurement during the presurvey. If the source is below 59° C, measure the wet bulb and dry bulb temperatures, and calculate the moisture content using a psychrometric chart. At higher temperatures, use Method 4 to determine the moisture content.

5.4 Determination of Static Pressure. Obtain the static pressure from the plant personnel or measurement. If a type S pitot tube and an inclined manometer are used, take care to align the pitot tube 90° from the direction of the flow. Disconnect one of the tubes to the manometer, and read the static pressure; note whether the reading is positive or negative.

5.5 Collection of Presurvey Samples with Adsorption Tube. Follo Section 7.4 for presurvey sampling.

6. *Analysis Development*

Presurvey samples shall be used to develop and confirm the best sampling and analysis scheme.

6.1 Selection of GC Parameters.

6.1.1 Column Choice. Based on the initial contact with plant personnel concerning the plant process and the anticipated emissions, choose a column that provides good resolution and rapid analysis time. The choice of an appropriate column can be aided by a literature search, contact with manufacturers of GC columns, and discussion with personnel at the emission source.

Most column manufacturers keep excellent records of their products. Their technical service departments may be able to recommend appropriate columns and detector type for separating the anticipated compounds, and they may be able to provide information on interferences, optimum operating conditions, and column limitations.

Plants with analytical laboratories may be able to provide information on their analytical procedures, including extractions, detector type, column types, compounds emitted, and approximate concentrations.

6.1.2 Preliminary GC Adjustment. Using the standards and column obtained in Section 6.1.1, perform initial tests to dertermine appropriate GC conditions that provide good resolution and minimum analysis time for the compounds of interest.

6.1.3 Preparation of Presurvey Samples. If the samples were collected on an adsorbent, extract the sample as recommended by the manufacturer for removal of the compounds with a solvent suitable to the type of GC analysis. Prepare other samples in an appropriate manner.

6.1.4 Presurvey Sample Analysis. Before analysis, heat the presurvey sample to the duct temperature to vaporize any condensed material. Analyze the samples by the GC procedure, and compare the retention times against those of the calibration samples that contain the components expected to be in the stream. If any compounds cannot be identified with certainty by this procedure, identify them by other means such as GC/mass spectroscopy (GC/MS) or GC/infrared techniques. A GC/MS system is recommended.

Use the GC conditions determined by the procedures of Section 6.1.2 for the first injection. Vary the GC parameters during subsequent injections to determine the optimum settings. Once the optimum settings have been determined, perform repeat injections of the sample to determine the retention time of each compound. To inject a sample, draw sample through the loop at a constant rate (100 ml/min for 30 seconds). Be careful not to pressurize the gas in the loop. Turn off the pump and allow the gas in the sample loop to come to ambient pressure. Activate the sample valve, and record injection time, loop temperature, column temperature, carrier flow rate, chart speed, and attenuator setting. Calculate the retention time of each peak using the distance from injection to the peak maximum divided by the chart speed. Retention times should be repeatable within 0.5 seconds.

If the concentrations are too high for appropriate detector response, a smaller sample loop or dilutions may be used for gas samples, and, for liquid samples, dilution with solvent is appropriate. Use the standard curves (Section 6.3) to obtain an estimate of the concentrations.

Identify all peaks by comparing the known retention times of compounds expected to be in the retention times of peaks in the sample. Identify any remaining unidentified peaks which have areas larger than 5 percent of the total using a GC/MS, or estimation of possible compounds by their retention times compared to known compounds, with confirmation by further GC analysis.

6.2 Calibration Standards. If the presurvey samples are collected in an adsorbent tube (charcoal, XAD-2, Tenax, etc.), prepare the standards in the same solvent used for the extraction procedure for the adsorbent. Prepare several standards for each compound throughout the range of the sample.

6.2.1 Cylinder Calibration Gases. If available, use NBS reference gases or commercial gas mixtures certified through direct analysis for the calibration curves.

6.2.1.1 Optional Cylinder Approach. As an alternative procedure, maintain high and low calibration standards. Use the high concentration (50 to 100 ppm) standard to prepare a three-point calibration curve with an appropriate dilution technique. Use this

same approach also to verify the dilution techniques for high-concentration source gases.

To prepare the diluted calibration samples, use calibrated rotameters to meter both the high concentration calibration gas and the diluent gas. Adjust the flow rates through the rotameters with micrometer valves to obtain the desired dilutions. A positive displacement pump or other metering techniques may be used in place of the rotameter to provide a fixed flow of high concentration gas.

To calibrate the rotameters, connect each rotameter between the diluent gas supply and a suitably sized bubble meter, spirometer, or wet test meter. While it is desirable to calibrate the calibration gas flowmeter with calibration gas, generally the available amount of this gas will preclude it. The error introduced by using the diluent gas is insignificant for gas mixtures of up to 1,000 to 2,000 ppm of each organic component. Record the temperature and atmospheric pressures as follows:

$$Q_2 = Q_1\left(\frac{P_2T_1}{P_1T_2}\right)^{1/2} \quad \text{Eq. 18-1}$$

Where:

Q_2 = Flow rate at new absolute temperature (T_2) and new absolute pressure (P_2).

Q_1 = Flow rate at calibration absolute temperature (T_1) and absolute pressure (P_1).

Connect the rotameters to the calibration and diluent gas supplies using 6-mm Teflon tubing. Connect the outlet side of the rotameters through a connector to a leak-free Tedlar bag as shown in Figure 18.5. (See Section 7.1 for leak check procedures.) Adjust the gas flows to provide the desired dilution, and fill the bag with sufficient gas for calibration. Be careful not to fill to the point where it applies additional pressure on the gas. Record the flow rates of both rotameters, the ambient temperature, and atmospheric pressure. Calculate the concentration of diluted gas as follows:

$$C_a = \frac{10^6(\bar{X}_a\, q_a)}{q_a + q_d} \quad \text{Eq. 18-2}$$

Where:

C_a = Concentration of component "a" in ppm.

$\bar{X}_a$ = Mole fraction of component "a" in the calibration gas to be diluted.

q_a = Flow rate of the calibration gas contains mg component "a" at measured temperature and pressure.

q_d = Diluent gas flow at measured temperature and pressure.

Use single-stage dilutions to prepare calibration mixtures up to about 1:20 dilution factor. For greater dilutions, use a double dilution system. Assemble the apparatus, as shown in Figure 18-6, using calibrated flowmeters of suitable range. Adjust the control valves so that about 90 percent of the diluted gas from the first stage is exhausted, and 10 percent goes to the second stage flowmeter. Fill the Tedlar bag with the dilute gas from the second stage. Record the temperature, ambient pressure, and water manometer pressure readings. Correct the flow reading in the first stage as indicated by the water manometer reading. Calculate the concentration of the component in the final gas mixture as follows:

$$C_a = 10^6\,\bar{X}_a\left(\frac{q_a1}{q_a1+q_d1}\right)\left(\frac{q_a2}{q_a2+q_d2}\right) \quad \text{Eq. 18-3}$$

Where:

C_a = Concentration of component "a" in ppm.

$\bar{X}_a$ = Mole fraction of component "a" in original gas.

q_a1 = Flow rate of component "a" in stage 1.

q_a2 = Flow rate of component "a" in stage 2.

q_d1 = Flow rate of diluent gas in stage 1.

q_d2 = Flow rate of diluent gas in stage 2.

Further details of the calibration methods for rotameters and the dilution system can be found in Citation 21 in Section 8.

6.2.2 Preparation of Standards from Volatile Materials. Record all data shown on Figure 18-3.

6.2.2.1 Bag Technique. Evacuate a 10-liter Tedlar bag that has passed a leak check (see Section 7.1), and meter in 5.0 liters of nitrogen through a 0.5 liter per revolution dry test meter. While the bag is filling, use a 0.5-ml syringe to inject a known quantity of the material of interest through the wall of the bag or through a septum—caped tee at the bag inlet. Withdraw the syringe needle, and immediately cover the resulting hole with a piece of masking tape. In a like manner, prepare dilutions having other concentrations. Prepare a minimum of three concentrations. Place each bag on a smooth surface, and alternately depress opposite sides of the bag 50 times to mix the gases. Record the average meter temperature, gas volume, liquid volume, barometric pressure, and meter pressure.

Set the electrometer attenuator to the X1 Position. Flush the sampling loop with zero helium or nitrogen, and activate the sample valve. Record the injection time, sample loop temperature, column temperature, carrier gas flow rate, chart speed, and attenuator setting. Record peaks and detector responses that occur in the absence of any sample. Maintain conditions. Flush the sample loop for 30 seconds at the rate of 100 ml/min with one of the calibration mixtures, and open the sample valve. Record the injection time. Select the peak that corresponds to the compound of interest. Measure the distance on the chart from the injection time to the time at which the peak maximum occurs. Divide this quantity by the chart speed, and record the resulting value as the retention time.

6.2.2.2 Preparation of Standards from less Volatile Liquid Materials. Use the equipment shown in Figure 18-8. Calibrate the dry gas meter with a wet test meter or a spirometer. Use a water manometer for the pressure gauge and glass, Teflon, brass, or stainless steel for all connections. Connect a valve to the inlet of the 50-liter Tedlar bag.

To prepare the standards, assemble the equipment as shown in Figure 18-8, and leak check the system. Completely evacuate the bag. Fill the bag with hydrocarbon-free air, and evacuate the bag again. Close the inlet valve.

Turn on the hot plate, and allow the water to reach boiling. Connect the bag to the impinger outlet. Record the initial meter reading, open the bag inlet valve, and open the cylinder. Adjust the rate so that the bag will be completely filled in approximately 15 minutes. Record meter pressure, temperature, and local barometric pressure.

Fill the syringe to the desired liquid volume with the material to be evaluated. Place the syringe needle into the impinger inlet using the septum provided, and inject the liquid into the flowing air stream. Use a needle of sufficient length to permit injection of the liquid below the air inlet branch of the tee. Remove the syringe.

Complete filling of the bag; note and record the meter pressure and temperature at regular intervals, preferably 1 minute.

When the bag is filled, stop the pump, and close the bag inlet valve. Record the final meter reading.

Disconnect the bag from the impinger outlet, and set it aside for at least 1 hour to equilibrate. Analyze the sample within the proven life period of its preparation.

6.2.2.3 Concentration Calculations. Average the meter temperature (T_m) and pressure (P_m) readings over the bag filling process.

Measure the solvent liquid density at room temperature by accurately weighing a known volume of the material on an analytical balance to the nearest 1.0 milligram. Take care during the weighing to minimize evaporation of the material. A ground-glass stoppered 25-ml volumetric flask or a glass-stoppered specific gravity bottle is suitable for weighing. Calculate the result in terms of g/ml. As an alternative, literature values of the density of the liquid at 20°C may be used.

Calculate the concentration of material in the sample in mg/liter at standard conditions as follows:

$$C_{std\ sol} = \frac{760(L_v)(p)(273+T_m)}{273(M_f-M_i)(P_{bar}+P_m)} \quad \text{Eq. 18-4}$$

Where:

$C_{std\ sol}$ = Standard solvent concentration, mg/std liter.

L_v = Liquid volume injected, ml.

p = Liquid density at room temperature, g/ml.

T_m = Meter temperature, °C.

M_f, M_i = Final and initial meter reading, liters.

P_{bar} = Local barometric pressure (absolute), mm Hg.

P_m = Meter pressure (gauge), mm Hg.

6.3 Preparation of Calibration Curves. Obtain gas standards as described in Section 6.2 such that three concentrations per attentuator range are available. Establish proper GC conditioning, then flush the sampling loop for 30 seconds at a rate of 100 ml/min. Allow the sample loop pressure to equilibrate with atmospheric pressure, and activate the injection valve. Record the standard concentration, attentuator setting, injection time, chart speed, retention time.

peak area, sample loop, temperature, column temperature, and carrier gas flow rate. Repeat the standard injection until two consecutive injections give area counts within 5 percent of their average. The average multiplied by the attenuator setting is then the calibration area value for that concentration.

Repeat this procedure for each standard. Plot concentrations along the abscissa and the calibration area values along the ordinate. Perform a regression analysis, and draw the least squares line.

6.4 Optional Use of Prepared Cylinders for Dilution Calibration Checks, and Response Factor Determinations. A set of three standards of the major component in the emissions is required. This set of standards can be taken into the field and thereby replace the need to prepare standards as described in Section 6.2.2.

The high concentration standard can be run through the dilution system to assess the accuracy of the system. First, prepare a calibration curve using the three standards following the procedure described in Section 6.3. Then, prepare a dilute sample using the high concentration standard so that the dilute sample will fall within the lower limits of the calibration curve.

Next, analyze the dilute sample, and calculate the measured concentration from the calibration curve as described in Section 6.3. The dilute concentration calculated from the analysis shall be within 10 percent of the concentration expected from the dilution system; otherwise determine the source of error in the dilution system, and correct it.

The calibration curve from the cylinder standards for a single organic can also be related to the GC response curves of all the compounds in the source by response factors developed in the laboratory. In the field, the single calibration curve from the cylinder standards and the calculated response factors measured in the laboratory can then be used to replace the need to prepare and analyze calibration standards for each organic compound (see Section 6.5 on daily quality control procedure).

Recheck the relative peak area of one of the calibration standards daily to guard against degradation. If the relative peak areas on successive days differ by more than 5 percent, remake all of the standards before proceeding to the final sample analyses.

6.5 Evaluation of Calibration and Analysis Procedure. Immediately after the preparation of the calibration curve and prior to the final sample analyses, perform the analysis audit described in Part 61, Appendix C, Procedure 2: "Procedure for Field Auditing GC Analysis" (47 FR 39179, September 7, 1982). The information required to document the analysis of the audit samples has been included on the example data sheets shown in Figures 18-3 and 18-7. The audit analyses shall agree with the audit concentrations within 10 percent. When available, the tester may obtain audit cylinders by contacting: Environmental Protection Agency, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD-77), Research Triangle Park, North Carolina 27711. Audit cylinders obtained from a commercial gas manufacturer may be used provided: (a) the gas manufacturer certifies the audit cylinder as described in Section 5.2.3.1 of Method 23 and (b) the gas manufacturer obtains an independent analysis of the audit cylinders to verify this analysis. Independent analysis is defined as an analysis performed by an individual other than the individual who performs the gas manufacturer's analysis, while using calibration standards and analysis equipment different from those used for the gas manufacturer's analysis. Verification is complete and acceptable when the independent analysis concentration is within 5 percent of the gas manufacturer's concentration.

7. Final Sampling and Analysis Procedure

Considering safety (flame hazards) and the source conditions, select an appropriate sampling and analysis procedure (Section 7.1, 7.2, 7.3, or 7.4). In situations where a hydrogen flame is a hazard and no intrinsically safe GC is suitable, use the flexible bag collection technique or an adsorption technique. If the source temperature is below 100°C, and the organic concentrations are suitable for the detector to be used, use the direct interface method. If the source gases require dilution, use a dilution interface and either the bag sample or adsorption tubes. The choice between these two techniques will depend on the physical layout of the site, the source temperature, and the storage stability of the compounds if collected in the bag. Sample polar compounds by direct interfacing or dilution interfacing to prevent sample loss by adsorption on the bag.

7.1 Integrated Bag Sampling and Analysis

7.1.1 Evacuated Container Sampling Procedure. In this procedure, the bags are filled by evacuating the rigid air-tight container holding the bags. Therefore, check both the bags and the container for leaks before and after use as follows: Connect a water manometer using a tee connector between the bag or rigid container and a pressure source. Pressurize the bag or container to 5 to 10 cm H_2O (2 to 4 in. H_2O), and allow it to stand overnight. A deflated bag indicates a leak.

7.1.1.1 Apparatus.

7.1.1.1.1 Probe. Stainless steel, Pyrex glass, or Teflon tubing probe, according to the duct temperature, with 6.4-mm OD Teflon tubing of sufficient length to connect to the sample bag. Use stainless steel or Teflon unions to connect probe and sample line.

7.1.1.1.2 Quick Connects. Male (2) and female (2) of stainless steel construction.

7.1.1.1.3 Needle Valve. To control gas flow.

7.1.1.1.4 Pump. Leakless Teflon-coated diaphragm-type pump or equivalent. To deliver at least 1 liter/min.

7.1.1.1.5 Charcoal Adsorption Tube. Tube filled with activated charcoal, with glass wool plugs at each end, to adsorb organic vapors.

7.1.1.1.6 Flowmeter. 0 to 500-ml flow range; with manufacturer's calibration curve.

7.1.1.2 Sampling Procedure. To obtain a sample, assemble the sample train as shown in Figure 18-8. Leak check both the bag and the container. Connect the vacuum line from the needle valve to the Teflon sample line from the probe. Place the end of the probe at the centroid of the stack, and start the pump with the needle valve adjusted to yield a flow of 0.5 liter/minute. After allowing sufficient time to purge the line several times, connect the vacuum line to the bag, and evacuate until the rotameter indicates no flow. Then position the sample and vacuum lines for sampling, and begin the actual sampling, keeping the rate proportional to the stack velocity. As a precaution, direct the gas exiting the rotameter away from sampling personnel. At the end of the sample period, shut off the pump, disconnect the sample line from the bag, and disconnect the vacuum line from the bag container. Record the source temperature, barometric pressure, ambient temperature, sampling flow rate, and initial and final sampling time on the data sheet shown in Figure 18-10. Protect the Tedlar bag and its container from sunlight. When possible, perform the analysis within 2 hours of sample collection.

7.1.2 Direct Pump Sampling Procedure. Flow 7.1.1, except place the pump and needle valve between the probe and the bag. Use a pump and needle valve constructed of stainless steel or some other material not affected by the stack gas. Leak check the system, and then purge with stack gas before the connecting to the previously evacuated bag.

7.1.3 Explosion Risk Area Bag Sampling Procedure. Follow 7.1.1 except replace the pump with another evacuated can (see Figure 18-9a). Use this method whenever there is a possibility of an explosion due to pumps, heated probes, or other flame producing equipment.

7.1.4 Other Modified Bag Sampling Procedures. In the event that condensation is observed in the bag while collecting the sample and a direct interface system cannot be used, heat the bag during collection, and maintain it at a suitably elevated temperature during all subsequent operations. (Note: Take care to leak check the system prior to the dilutions so as not to create a potentially explosive atmosphere.) As an alternative, collect the sample gas, and simultaneously dilute it in the Tedlar bag.

In the first procedure, heat the box containing the sample bag to the source temperature, provided the components of the bag and the surrounding box can withstand this temperature. Then transport the bag as rapidly as possible to the analytical area while maintaining the heating, or cover the box with an insulating blanket. In the analytical area, keep the box heated to source temperature until analysis. Be sure that the method of heating the box and the control for the heating circuit are compatible with the safety restrictions required in each area.

To use the second procedure, prefill the Tedlar bag with a known quantity of inert gas. Meter the inert gas into the bag according to the procedure for the preparation of gas concentration standards of volatile liquid materials (Section 6.2.2.2), but eliminate the midget impinger section. Take the partly filled bag to the source, and meter the source gas into the bag through heated sampling lines and a heated flowmeter, or

Teflon positive displacement pump. Verify the dilution factors periodically through dilution and analysis of gases of known concentration.

7.1.5 Analysis of Bag Samples. Connect the needle valve, pump, charcoal tube, and flowmeter to draw gas samples through the gas sampling valve. Flush the sample loop with gas from one of the three Tedlar bags containing a calibration mixture, and analyze the sample. Obtain at least two chromatograms for the sample. The results are acceptable when the peak areas from two consecutive injections agree to within 5 percent of their average. If they do not agree, run additional samples until consistent area data are obtained. If this agreement is not obtained, correct the instrument technique problems before proceeding. If the results are acceptable, analyze the other two calibration gas mixtures in the same manner. Prepare the calibration curve by using the least squares method.

Analyze the two field audit samples as described in Section 6.5 by connecting each Tedlar bag containing an audit gas mixture to the sampling valve. Calculate the results; record and report the data to the audit supervisor. If the results are acceptable, proceed with the analysis of the source samples.

Analyze the source gas samples by connecting each bag to the sampling valve with a piece of Teflon tubing identified with that bag. Follow the restrictions on replicate samples specified for the calibration gases. Record the data. Analyze the other two bag samples of source gas in the same manner. After all three bag samples have been analyzed, repeat the analysis of the calibration gas mixtures. Use the average of the two calibration curves to determine the respective sample concentrations. If the two calibration curves differ by more than 5 percent from their mean value, then report the final results by both calibration curves.

7.1.6 Determination of Bag Water Vapor Content. Measure the ambient temperature and barometric pressure near the bag. From a water saturation vapor pressure table, determine and record the water vapor content of the bag as a decimal figure. (Assume the relative humidity to be 100 percent unless a lesser value is known.)

Use the field analytical data sheet as shown in Figure 18-11. The sheet has been designed to tabulate information from the bag collection, direct interface, and dilution interface systems; as a result, not all of the requested information will apply to any single method. Note the data that do not apply with the notation "N.A." Summarize the analysis.

7.2 Direct Interface Sampling and Analysis Procedure. The direct interface procedure can be used provided that the moisture content of the gas does not interfere with the analysis procedure, the physical requirements of the equipment can be met at the site, and the source gas concentration is low enough that detector saturation is not a problem. Adhere to all safety requirements with this method.

7.2.1 Apparatus.

7.2.1.1 Probe. Constructed of stainless steel, Pyrex glass, or Teflon tubing as required by duct temperature, 6.4-mm OD, enlarged at duct end to contain glass wool plug. If necessary, heat the probe with heating tape or a special heating unit capable of maintaining duct temperature.

7.2.1.2 Sample Lines. 6.4-mm OD Teflon lines, heat-traced to prevent condensation of material.

7.2.1.3 Quick Connects. To connect sample line to gas sampling valve on GC instrument and to pump unit used to withdraw source gas. Use a quick connect or equivalent on the cylinder or bag containing calibration gas to allow connection of the calibration gas to the gas sampling valve.

7.2.1.4 Thermocouple Readout Device. Potentiometer or digital thermometer, to measure source temperature and probe temperature.

7.2.1.5 Heated Gas Sampling Valve. Of two-position, six-port design, to allow sample loop to be purged with source gas or to direct source gas into the GC instrument.

7.2.1.6 Needle Valve. To control gas sampling rate from the source.

7.2.1.7 Pump. Leakless Teflon-coated diaphragm-type pump or equivalent, capable of at least 1 liter/minute sampling rate.

7.2.1.8 Flowmeter. Of suitable range to measure sampling rate.

7.2.1.9 Charcoal Adsorber. To adsorb organic vapor collected from the source to prevent exposure of personnel to source gas.

7.2.1.10 Gas Cylinders. Carrier gas (helium or nitrogen), and oxygen and hydrogen for a flame ionization detector (FID) if one is used.

7.2.1.11 Gas Chromatograph. Capable of being moved into the field, with detector, heated gas sampling valve, column required to complete separation of desired components, and option for temperature programming.

7.2.1.12 Recorder/Integrator. To record results.

7.2.2 Procedure. To obtain a sample, assemble the sampling system as shown in Figure 18-12. Make sure all connections are tight. Turn on the probe and sample line heaters. As the temperature of the probe and heated line approaches the source temperature as indicated on the thermocouple readout device, control the heating to maintain a temperature of 0 to 3°C above the source temperature. While the probe and heated line are being heated, disconnect the sample line from the gas sampling valve, and attach the line from the calibration gas mixture. Flush the sample loop with calibration gas and analyze a portion of that gas. Record the results. After the calibration gas sample has been flushed into the GC instrument, turn the gas sampling valve to flush position, then reconnect the probe sample line to the valve. Move the probe to the sampling position, and draw source gas into the probe, heated line, and sample loop. After thorough flushing, analyze the sample using the same conditions as for the calibration gas mixture. Repeat the analysis on an additional sample. Measure the peak areas for the two samples, and if they do not agree to within 5 percent of their mean value, analyze additional samples until two consecutive analyses meet this criteria. Record the data. After consistent results are obtained, remove the probe from the source and analyze a second calibration gas mixture. Record this calibration data and the other required data on the data sheet shown in Figure 18-11, deleting the dilution gas information.

(Note.—Take care to draw all samples, calibration mixtures, and audits through the sample loop at the same pressure.)

In addition, analyze the field audit samples by connecting the audit sample cylinders to the gas sampling valve. Use the same instrument conditions as were used for the source samples. Record the data, and report the results of these analyses to the audit supervisor.

7.3 Dilution Interface Sampling and Analysis Procedure. Source samples that contain a high concentration of organic materials may require dilution prior to analysis to prevent saturating the GC detector. The apparatus required for this direct interface procedure is basically the same as that described in the Section 7.2, except a dilution system is added between the heated sample line and the gas sampling valve. The apparatus is arranged so that either a 10:1 or 100:1 dilution of the source gas can be directed to the chromatograph. A pump of larger capacity is also required, and this pump must be heated and placed in the system between the sample line and the dilution apparatus.

7.3.1 Apparatus. The equipment required in addition to that specified for the direct interface system is as follows:

7.3.1.1 Sample Pump. Leakless Teflon-coated diaphragm-type that can withstand being heated to 120°C and deliver 1.5 liters/minute.

7.3.1.2 Dilution Pumps. Two Model A-150 Komhyr Teflon positive displacement type delivering 150 cc/minute, or equivalent. As an option, calibrated flowmeters can be used in conjunction with Teflon-coated diaphragm pumps.

7.3.1.3 Valves. Two Teflon three-way valves, suitable for connecting to 6.4-mm OD Teflon tubing.

7.3.1.4 Flowmeters. Two, for measurement of diluent gas, expected delivery flow rate to be 1,350 cc/min.

7.3.1.5 Diluent Gas with Cylinders and Regulators. Gas can be nitrogen or clean dry air, depending on the nature of the source gases.

7.3.1.6 Heated Box. Suitable for being heated to 120°C, to contain the three pumps, three-way valves, and associated connections. The box should be equipped with quick connect fittings to facilitate connection of: (1) The heated sample line from the probe, (2) the gas sampling valve, (3) the calibration gas mixtures, and (4) diluent gas lines. A schematic diagram of the components and connections is shown in Figure 18-13.

(Note.—Care must be taken to leak check the system prior to the dilutions so as not to create a potentially explosive atmosphere.)

The heated box shown in Figure 18-13 is designed to receive a heated line from the probe. An optional design is to build a probe unit that attaches directly to the heated box.

In this way, the heated box contains the controls for the probe heaters, or, if the box is placed against the duct being sampled, it may be possible to eliminate the probe heaters. In either case, a heated Teflon line is used to connect the heated box to the gas sampling valve on the chromatograph.

7.3.2 Procedure. Assemble the apparatus by connecting the heated box, shown in Figure 18-13, between the heated sample line from the probe and the gas sampling valve on the chromatograph. Vent the source gas from the gas sampling valve directly to the charcoal filter, eliminating the pump and rotameter. Heat the sample probe, sample line, and heated box. Insert the probe and source thermocouple at the centroid of the duct. Measure the source temperature, and adjust all heating units to a temperature 0 to 3°C above this temperature. If this temperature is above the safe operating temperature of the Teflon components, adjust the heating to maintain a temperature high enough to prevent condensation of water and organic compounds. Verify the operation of the dilution system by analyzing a high concentration gas of known composition through either the 10:1 or 100:1 dilution stages, as appropriate. (If necessary, vary the flow of the diluent gas to obtain other dilution ratios.) Determine the concentration of the diluted calibration gas using the dilution factor and the calibration curves prepared in the laboratory. Record the pertinent data on the data sheet shown in Figure 18-11. If the data on the diluted calibration gas are not within 10 percent of the expected values, determine whether the chromatograph or the dilution system is in error, and correct it. Verify the GC operation using a low concentration standard by diverting the gas into the sample loop, bypassing the dilution system. If these analyses are not within acceptable limits, correct the dilution system to provide the desired dilution factors. Make this correction by diluting a high-concentration standard gas mixture to adjust the dilution ratio as required.

Once the dilution system and GC operations are satisfactory, proceed with the analysis of source gas, maintaining the same dilution settings as used for the standards. Repeat the analyses until two consecutive values do not vary by more than 5 percent from their mean value are obtained.

Repeat the analysis of the calibration gas mixtures to verify equipment operation. Analyze the two field audit samples using either the dilution system, or directly connect to the gas sampling valve as required. Record all data and report the results to the audit supervisor.

7.4 Adsorption Tube Procedure (Alternative Procedure). It is suggested that the tester refer to the National Institute of Occupational Safety and Health (NIOSH) method for the particular organics to be sampled. The principal interferent will be water vapor. If water vapor is present at concentrations above 3 percent, silica gel should be used in front of the charcoal. Where more than one compound is present in the emissions, then develop relative adsorptive capacity information.

7.4.1 Additional Apparatus. In addition to the equipment listed in the NIOSH method for the particular organic(s) to be sampled, the following items (or equivalent) are suggested.

7.4.1.1 Probe (Optional). Borosilicate glass or stainless steel, approximately 6-mm ID, with a heating system if water condensation is a problem, and a filter (either in-stack or out-stack heated to stack temperature) to remove particulate matter. In most instances, a plug of glass wool is a satisfactory filter.

7.4.1.2 Flexible Tubing. To connect probe to adsorption tubes. Use a material that exhibits minimal sample adsorption.

7.4.1.3 Leakless Sample Pump. Flow controlled, constant rate pump, with a set of limiting (sonic) orifices to provide pumping rates from approximately 10 to 100 cc/min.

7.4.1.4 Bubble-Tube Flowmeter. Volume accuracy within ± 1 percent, to calibrate pump.

7.4.1.5 Stopwatch. To time sampling and pump rate calibration.

7.4.1.6 Adsorption Tubes. Similar to ones specified by NIOSH, except the amounts of adsorbent per primary/backup sections are 800/200 mg for charcoal tubes and 1040/260 mg for silica gel tubes. As an alternative, the tubes may contain a porous polymer adsorbent such as Tenax GC or XAD-2.

7.4.1.7 Barometer. Accurate to 5 mm Hg, to measure atmospheric pressure during sampling and pump calibration.

7.4.1.8 Rotameter. 0 to 100 cc/min, to detect changes in flow rate during sampling.

7.4.2 Sampling and Analysis. It is suggested that the tester follow the sampling and analysis portion of the respective NIOSH method section entitled "Procedure." Calibrate the pump and limiting orifice flow rate through adsorption tubes with the bubble tube flowmeter before sampling. The sample system can be operated as a "recirculating loop" for this operation. Record the ambient temperature and barometric pressure. Then, during sampling, use the rotameter to verify that the pump and orifice sampling rate remains constant.

Use a sample probe, if required. Minimize the length of flexible tubing between the probe and adsorption tubes. Several adsorption tubes can be connected in series, if the extra adsorptive capacity is needed. Provide the gas sample to the sample system at a pressure sufficient for the limiting orifice to function as a sonic orifice. Record the total time and sample flow rate (or the number of pump strokes), the barometric pressure, and ambient temperature. Obtain a total sample volume commensurate with the expected concentration(s) of the volatile organic(s) present, and recommended sample loading factors (weight sample per weight adsorption media). Laboratory tests prior to actual sampling may be necessary to predetermine this volume. When more than one organic is present in the emissions, then develop relative adsorptive capacity information. If water vapor is present in the sample at concentrations above 2 to 3 percent, the adsorptive capacity may be severely reduced. Operate the gas chromatograph according to the manufacturer's instructions. After establishing optimum conditions, verify and document these conditions during all operations. Analyze the audit samples (see Section 7.4.4.3), then the emission samples. Repeat the analysis of each sample until the relative deviation of two consecutive injections does not exceed 5 percent.

7.4.3 Standards and Calibration. The standards can be prepared according to the respective NIOSH method. Use a minimum of three different standards; select the concentrations to bracket the expected average sample concentration. Perform the calibration before and after each day's sample analyses. Prepare the calibration curve by using the least squares method.

7.4.4 Quality Assurance.

7.4.4.1 Determination of Desorption Efficiency. During the testing program, determine the desorption efficiency in the expected sample concentration range for each batch of adsorption media to be used. Use an internal standard. A minimum desorption efficiency of 50 percent shall be obtained. Repeat the desorption determination until the relative deviation of two consecutive determinations does not exceed 5 percent. Use the average desorption efficiency of these two consecutive determinations for the correction specified in Section 7.4.4.5. If the desorption efficiency of the compound(s) of interest is questionable under actual sampling conditions, use of the Method of Standard Additions may be helpful to determine this value.

7.4.4.2 Determination of Sample Collection Efficiency. For the source samples, analyze the primary and backup portions of the adsorption tubes separately. If the backup portion exceeds 10 percent of the total amount (primary and backup), repeat the sampling with a larger sampling portion.

7.4.4.3 Analysis Audit. Immediately before the sample analyses, analyze the two audits in accordance with Section 7.4.2. The analysis audit shall agree with the audit concentration with 10 percent.

7.4.4.4 Pump Leak Checks and Volume Flow Rate Checks. Perform both of these checks immediately after sampling with all sampling train components in place. Perform all leak checks according to the manufacturer's instructions, and record the results. Use the bubble-tube flowmeter to measure the pump volume flow rate with the orifice used in the test sampling, and the result. If it has changed by more than 5 but less than 20 percent, calculate an average flow rate for the test. If the flow rate has changed by more than 20 percent, recalibrate the pump and repeat the sampling.

7.4.4.5 Calculations. All calculations can be performed according to the respective NIOSH method. Correct all sample volumes to standard conditions. If a sample dilution system has been used, multiply the results by the appropriate dilution ratio. Correct all results by dividing by the desorption efficiency (decimal value). Report results as ppm by volume, dry basis.

7.5 Reporting of Results. At the completion of the field analysis portion of the study, ensure that the data sheets shown in Figure 18-11 have been completed. Summarize this data on the data sheets shown in Figure 18-15.

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BILLING CODE 6560-50-M

I. Name of company _____ Date _____
Address _____
_____
Contacts _____ Phone _____
_____ _____
Process to be sampled _____
_____
_____
Duct or vent to be sampled _____
_____

II. Process description _____
_____
_____
_____
_____
Raw material _____
_____
_____
Products _____
_____
_____
Operating cycle
Check: Batch _____ Continuous _____ Cyclic _____
Timing of batch or cycle _____
Best time to test _____

Figure 18-1. Preliminary survey data sheet.

III. Sampling site
A. Description
Site description _____
Duct shape and size _____
Material _____
Wall thickness _____ inches
Upstream distance _____ inches _____ diameter
Downstream distance _____ inches _____ diameter
Size of port _____
Size of access area _____
Hazards _____ Ambient temp. _____ °F

B. Properties of gas stream
Temperature _____ °C _____ °F, Data source _____
Velocity _____, Data source _____
Static pressure ___ inches H_2O, Data source _____
Moisture content _____ %, Data source _____
Particulate content _____, Data source _____
Gaseous components

		Hydrocarbons	ppm
N_2	%		
O_2	%		
CO	%		
CO_2	%		
SO_2	%		

Hydrocarbon components

		ppm
		ppm
		ppm
		ppm
		ppm
		ppm

Figure 18-1 (continued). Preliminary survey data sheet.

C. Sampling considerations

Location to set up GC _____

_____

Special hazards to be considered _____

_____

Power available at duct _____

Power available for GC _____

Plant safety requirements _____

_____

Vehicle traffic rules _____

_____

Plant entry requirements _____

_____

Security agreements _____

_____

Potential problems _____

_____

D. Site diagrams. (Attach additional sheets if required).

Figure 18-1 (continued). Preliminary survey data sheet.

Components to be analyzed	Expected concentration

Suggested chromatographic column _____

_____

Column flow rate ____ ml/min Head pressure____ mm Hg

Column temperature:

Isothermal _____ °C

Programmed from _____ °C to ____ °C at ____ °C/min

Injection port/sample loop temperature _____ °C

Detector temperature _____ °C

Detector flow rates: Hydrogen _____ ml/min.

head pressure____ mm Hg

Air/Oxygen _____ ml/min,

head pressure____ mm Hg

Chart speed _____ inches/minute

Compound data:

Compound	Retention time	Attenuation

Figure 18-2. Chromatographic conditions data sheet.

Calibration Curve Data - Volatile and Liquid Samples Collected in a Tedlar Bag

	Blank	Mixture 1	Mixture 2	Mixture 3
Size of Tedlar bag (liters)				
Dilution gas (name)				
Vol. of dilution gas (liters)				
Component (name)				
Volume of component (ml)				
Average meter temp. (°C)				
Average meter pressure (nm)				
Atmospheric pressure (nm)				
Density of liquid component (g/ml)				
Sample loop volume (ml)				
Sample loop temp. (°C)				
Carrier gas flow rate (ml/min)				
Column temperature				
initial (°C)				
program rate (°C/min)				
final (°C)				
Injection time (24 hr. basis)				
Distance to peak (cm)				
Chart speed (cm/min)				
Retention time (min)				
Calculated concentration (ppm)				
Attenuator setting				
Peak height (mm)				
Peak area (mm^2)				
Area x attenuation				

Plot peak area x attenuation against concentration to obtain calibration curve.

Figure 18-3.- Calibration curve data sheet - injection of volatile sample into Tedlar bag.

Rotameter number _____

Gas used _____

Method: Bubble meter _____ Spirometer _____ Wet test meter _____

Rotameter construction _____

Float type _____

Laboratory temperature (T obs.) _____ °C _____ °F

Laboratory pressure (P obs.) _____ in Hg _____ mm Hg

1. Flowmeter reading	Time (min)	Gas volume[a]	Flow rate (lab conditions)[b]

[a] Vol. of gas may be measured in milliliters, liters or cubic feet.

[b] Convert to standard conditions (20° C and 760 mm Hg).

$$Q_{STD} = Q_{obs} \frac{760 \times T_{obs.}}{P_{obs.} \times 20}^{1/2}$$

Flowmeter reading	Flow rate (STD conditions)

Plot meter reading against flow rate (std) and draw smooth curve.

Figure 18-4. Rotameter calibration data sheet.

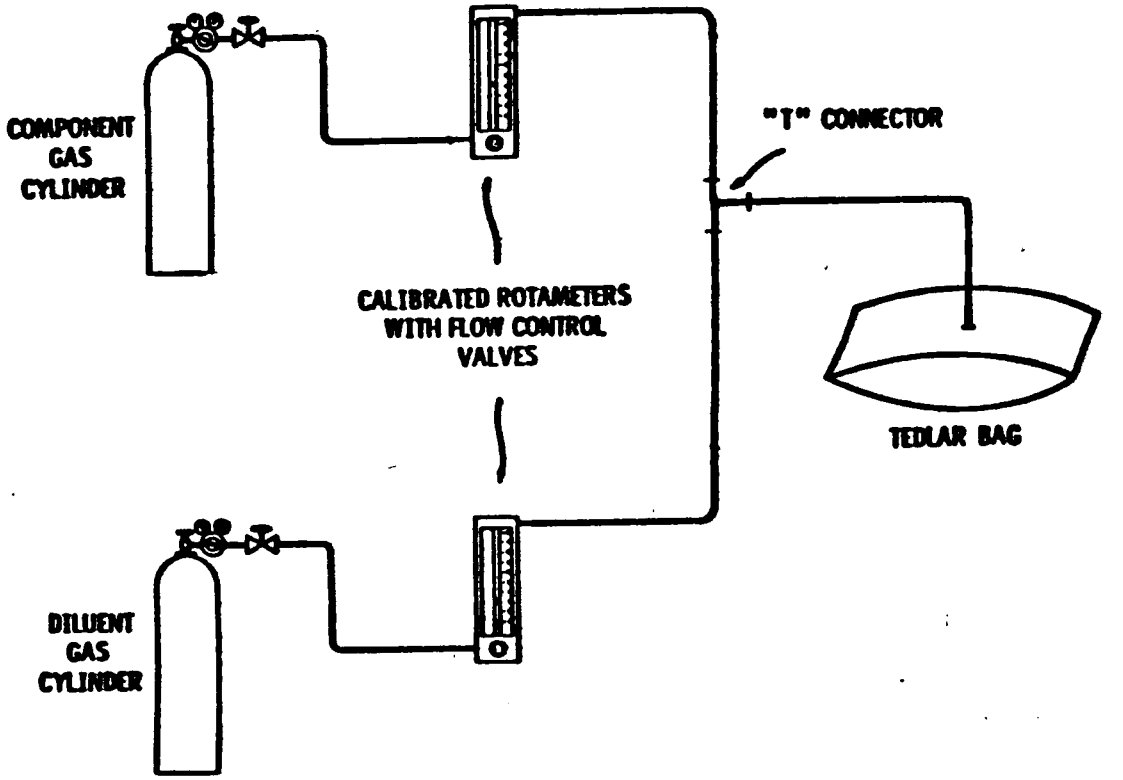

Figure 18-5. Single-stage calibration gas dilution system.

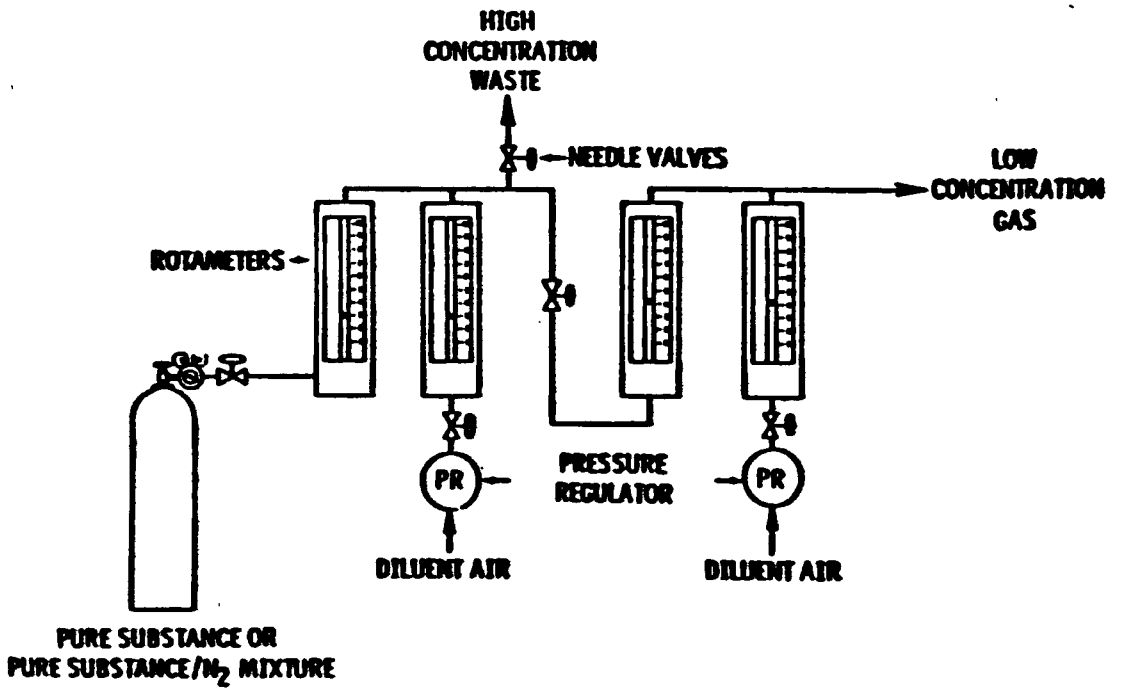

Figure 18-6. Two-stage dilution apparatus.

1. High concentration gas mixture

Component _____ Concentration _____ ppm

Diluent gas _____

2. Dilution and analysis data Date _____

Stage 1	Mixture 1	Mixture 2	Mixture 3
Component gas-rotameter reading			
Diluent gas-rotameter reading			
Ambient temp. (°C)			
Manometer reading, inches H_2O			
Flow rate component gas (ml/min)			
Flow rate diluent gas (ml/min)			
Stage 2			
Component gas-rotameter reading			
Diluent gas-rotameter reading			
Flow rate component gas (ml/min)			
Flow rate diluent gas (ml/min)			
Calculated concentration (ppm)			
Analysis			
Sample loop volume (ml)			
Sample loop temp. (°C)			
Carrier gas flow rate (ml/min)			
Column temperature			
initial (°C)			
program rate (°C/min)			
final (°C)			
Injection time (24-hr. basis)			
Distance to peak (inches)			
Chart speed (inch/min)			
Retention time (min)			
Attenuator factor			
Peak height (mm)			
Peak area (mm^2)			
Area x attenuation factor (mm^2)			

Plot peak area x attenuator factor against concentration to obtain calibration curve.

Figure 18-7. Calibration curve data sheet - dilution method.

3. Low concentration standard

Known concentration (ppm)	
Retention time (min)	
Injection time (24-hour basis)	
Attenuation factor	
Peak height (mm)	
Peak area (mm^2)	
Peak area x attenuation (mm^2)	
Calculated concentration (ppm)	
Deviation (%)	

4. Audit samples

	Sample 1	Sample 2
Retention time (min)		
Injection time 24-hour basis)		
Attenuation factor		
Peak height (mm)		
Peak area (mm^2)		
Peak area x attenuation factor		
Measured concentration		
Data reported on (date)		
Data reported by (initial)		
Certified concentration (ppm)		
Deviation (%)		

Note: If a pump is used instead of a rotameter for component gas flow, substitute pump delivery rate for rotameter readings).

Figure 18-7 (continued). Calibration curve data sheet - dilution method.

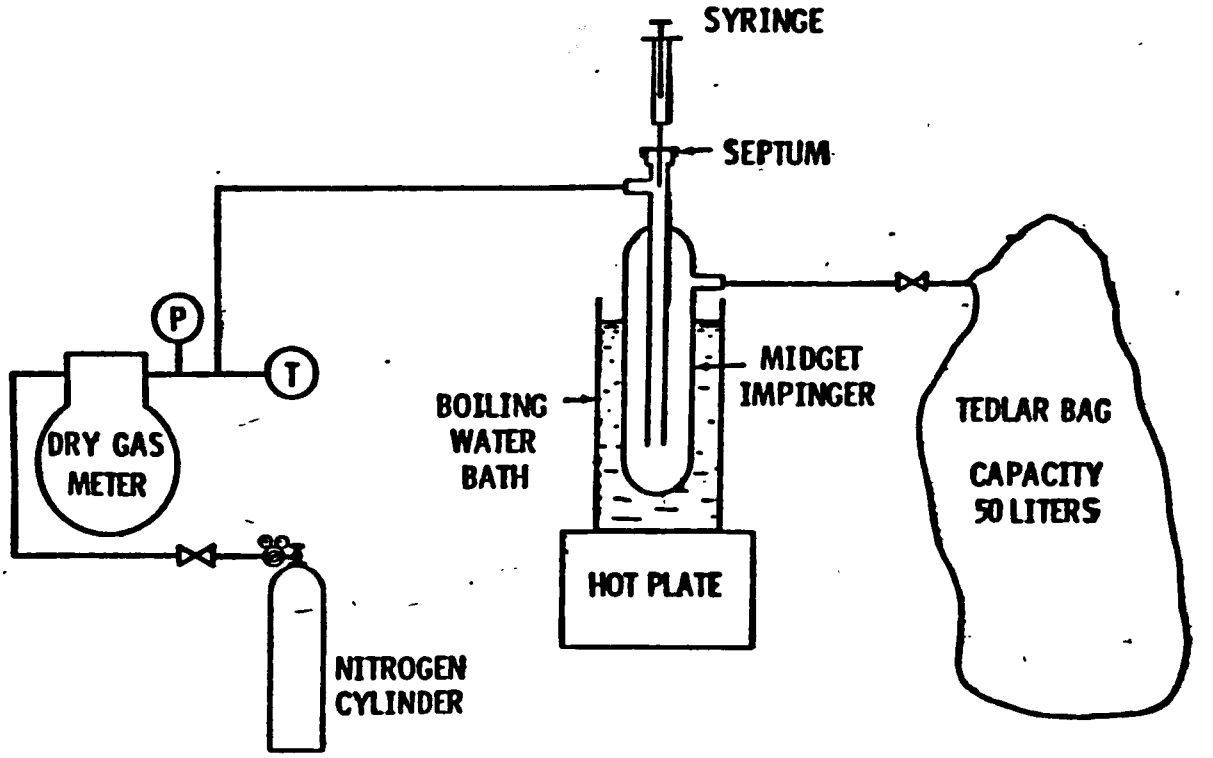

Figure 18-8. Apparatus for preparation of liquid materials.

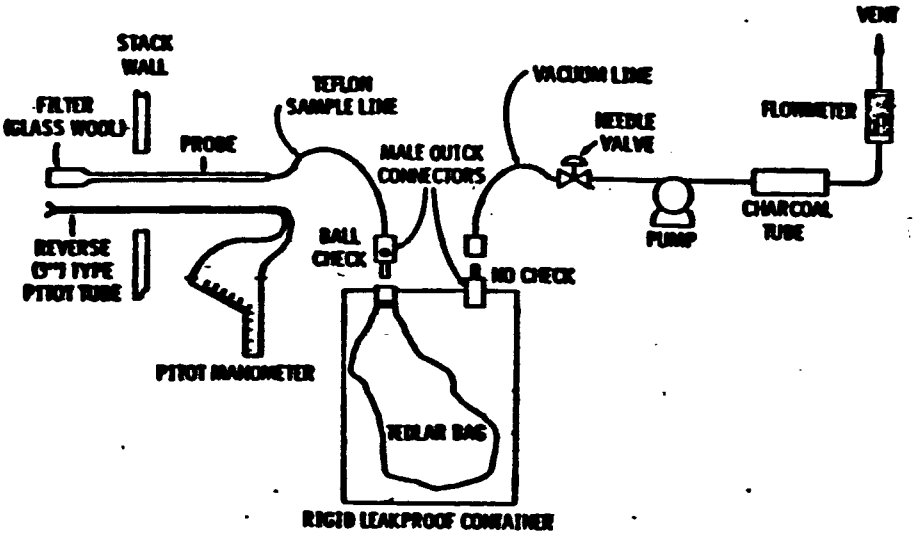

Figure 18-9. Integrated bag sampling train.

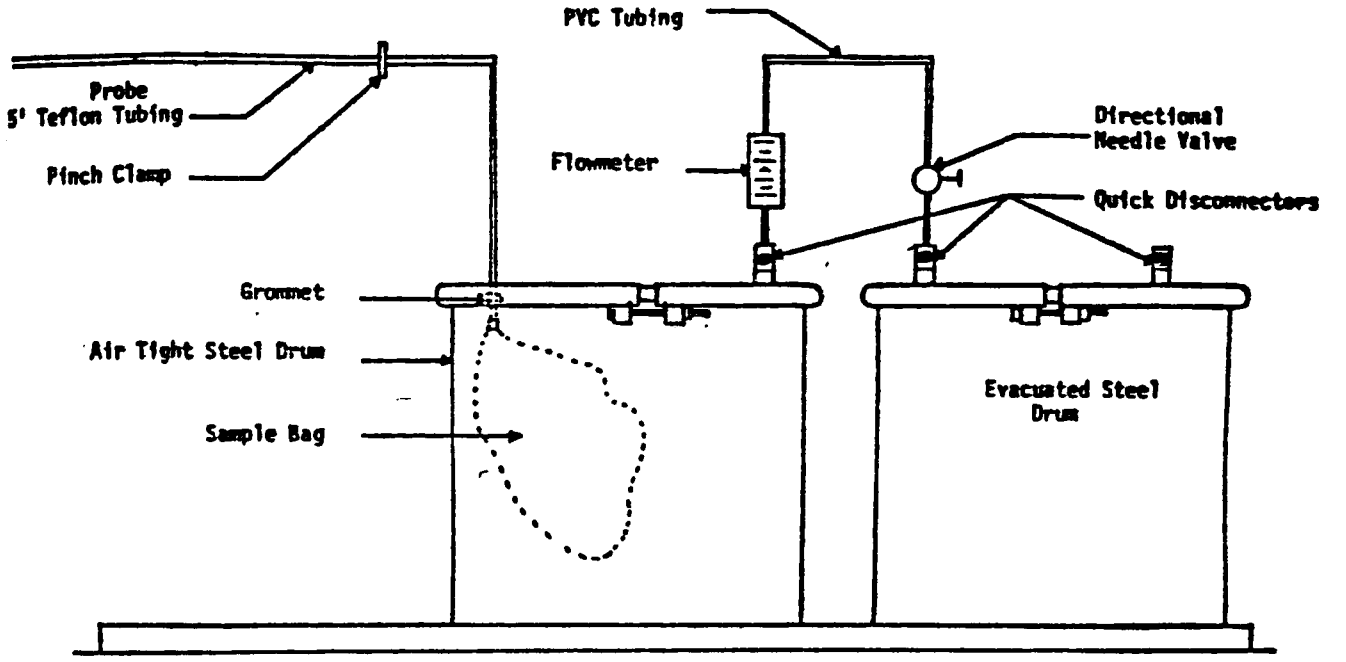

Figure 18-9a. Explosion risk gas sampling method.

Plant_____ Date_____

Site_____

	Sample 1	Sample 2	Sample 3
Source temperature (°C)			
Barometric pressure (mm Hg)			
Ambient temperature (°C)			
Sample flow rate (appr.)			
Bag number			
Start time			
Finish time			

Figure 18-10. Field sample data sheet - Tedlar bag collection method.

Plant_____ Date_____

Location_____

1. General information

Source temperature (°C)	
Probe temperature (°C)	
Ambient temperature (°C)	
Atmospheric pressure (mm)	
Source pressure ("Hg)	
Absolute source pressure (mm)	
Sampling rate (liter/min)	
Sample loop volume (ml)	
Sample loop temperature (°C)	
Columnar temperature:	
Initial (°C)/time (min)	
Program rate (°C/min)	
Final (°C)/time (min)	
Carrier gas flow rate (ml/min)	
Detector temperature (°C)	
Injection time (24-hour basis)	
Chart speed (mm/min)	
Dilution gas flow rate (ml/min)	
Dilution Gas used (symbol)	
Dilution ratio	

Figure 18-11. Field analysis data sheets.

2. Field Analysis Data - Calibration Gas

Run No._____ Time_____

Components	Area	Attenuation	A x A Factor	Conc. (ppm)

Run No._____ Time_____

Components	Area	Attenuation	A x A Factor	Conc. (ppm)

Run No._____ Time_____

Components	Area	Attenuation	A x A Factor	Conc. (ppm)

Figure 18-11 (continued). Field analysis data sheets.

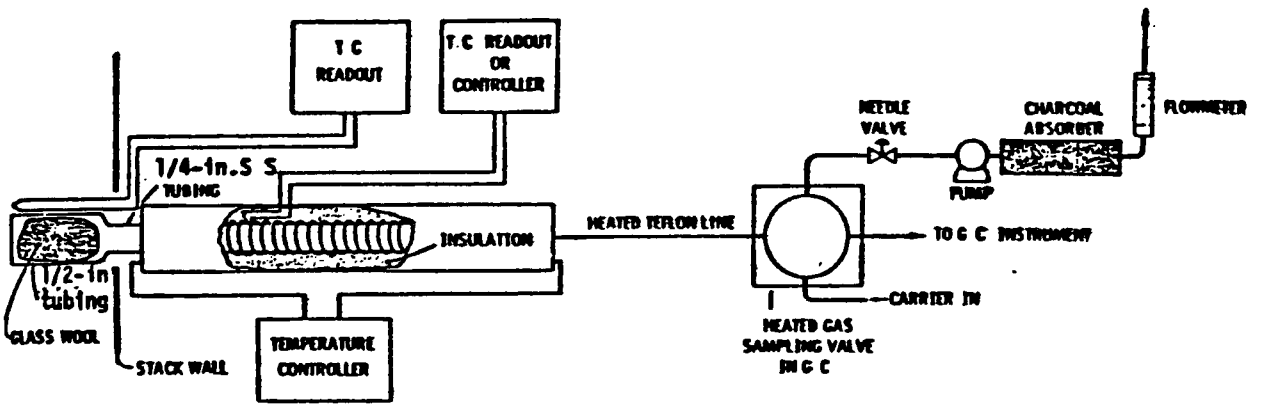

Figure 18-12. Direct interface sampling system.

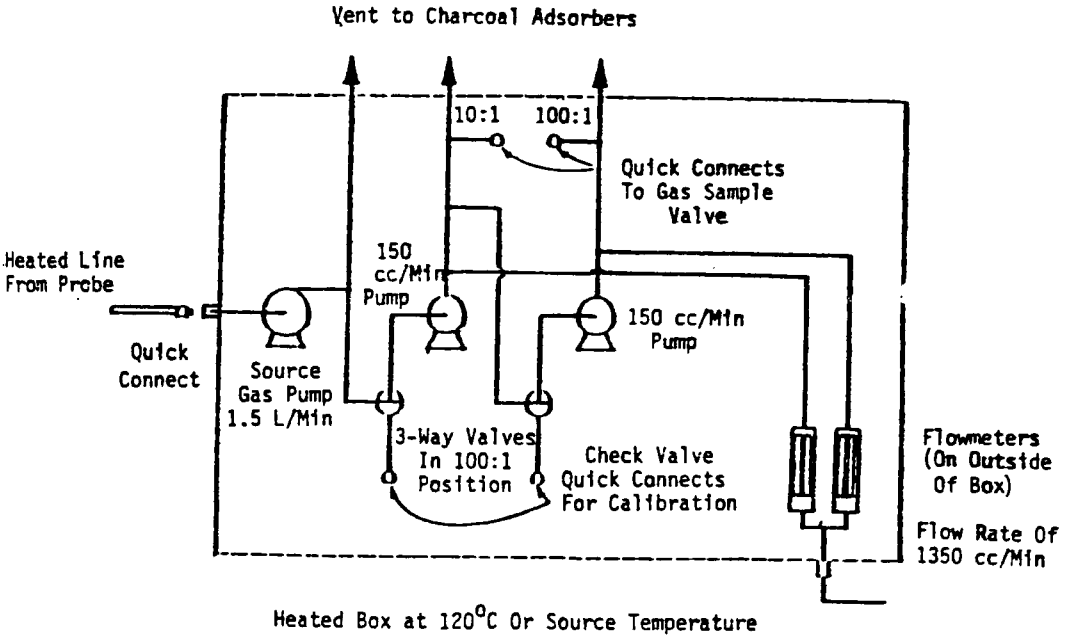

Figure 18-13. Schematic diagram of the heated box required for dilution of sample gas.

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Gaseous Organic Sampling and Analysis Check List

(Respond with initials or number as appropriate)

		Date
1 Presurvey data:		
A. Grab sample collected	☐	
B. Grab sample analyzed for composition	☐	
Method GC	☐	☐
GC/MS	☐	☐
Other	☐	☐
C. GC–FID analysis performed	☐	
2. Laboratory calibration data:		
A. Calibration curves prepared	☐	
Number of components	☐	☐
Number of concentrations/component (3 required)	☐	☐
B. Audit samples (optional):		
Analysis completed	☐	
Verified for concentration	☐	
OK obtained for field work	☐	
3. Sampling procedures:		
A. Method:		
Bag sample	☐	☐
Direct interface	☐	☐
Dilution interface	☐	☐
B. Number of samples collected	☐	
4. Field analysis:		
A. Total hydrocarbon analysis performed	☐	
B. Calibration curve prepared	☐	
Number of components	☐	☐
Number of concentrations per component (3 required)	☐	☐

Figure 18–14. Sampling and analysis check.

Gaseous Organic Sampling and Analysis Data

Plant— _____

Date— _____

Location— _____

	Source sample 1	Source sample 2	Source sample 3
1 General information:			
Source temperature (°C)			
Probe temperature (°C)			
Ambient temperature (°C)			
Atmospheric pressure (mm Hg)			
Source pressure (mm Hg)			
Sampling rate (ml/min)			
Sample loop volume (ml)			
Sample loop temperature (°C)			
Sample collection time (24-hr basis)			
Column temperature:			
Initial (°C)			
Program rate (°C/min)			
Final (°C)			
Carrier gas flow rate (ml/min)			
Detector temperature (°C)			
Chart speed (cm/min)			
Dilution gas flow rate (ml/min)			
Diluent gas used (symbol)			
Dilution ratio			

Performed by (signature): _____

Date: _____

Figure 18–14. Sampling and analysis sheet.

6. In Appendix A of Part 60, the title of Method 22 is revised to read as follows:

Method 22—Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares.

7. In Appendix A of Part 60, Section 1 of Method 22, *Introduction*, is amended by adding the following sentence to the end of the first paragraph:

* * * * *

This method is used also to determine visible smoke emissions from flares used for combustion of waste process materials.

8. In Appendix A of Part 60, Section 1 of Method 22, *Introduction*, is amended by removing the phrase "Reference Test" from the third sentence of the second paragraph.

9. In Appendix A of Part 60, Paragraph 2.1 of Section 2 of Method 22 is amended by adding a second paragraph as follows:

* * * * *

2.1 * * *

This method also is applicable for the determination of the frequency of visible smoke emissions from flares.

* * * * *

10. In Appendix A of Part 60, Paragraph 2.2 of Section 2 of Method 22 is revised as follows:

* * * * *

2.2 *Principle.* Fugitive emissions produced during material processing, handling, and transfer operations or smoke emissions from flares are visually determined by an observer without the aid of instruments.

* * * * *

11. In Appendix A of Part 60, Method 22 Section 3, *Definitions*, Paragraphs 3.4 and 3.5 are revised to read as follows:

* * * * *

3.4 *Smoke Emissions.* Pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission.

3.5 *Observation Period.* Accumulated time period during which observations are conducted, not to be less than the period specified in the applicable regulation.

* * * * *

12. In Appendix A of Part 60, Method 22 is amended by adding Figures 22–1 and 22–2 at the end of the method.

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BILLING CODE 6560-50-C

FUGITIVE OR SMOKE EMISSION INSPECTION
OUTDOOR LOCATION

Company _____	Observer _____
Location _____	Affiliation _____
Company representative _____	Date _____
Sky Conditions _____	Wind direction _____
Precipitation _____	Wind speed _____
Industry _____	Process unit _____

Sketch process unit; indicate observer position relative to source and sun; indicate potential emission points and/or actual emission points.

OBSERVATIONS	Clock time	Observation period duration, min:sec	Accumulated emission time, min sec
Begin Observation			
End observation			

Figure 22-1

Fugitive Emission Inspection Indoor Location Table

FUGITIVE EMISSION INSPECTION
INDOOR LOCATION

Company _____	Observer _____
Location _____	Affiliation _____
Company Representative _____	Date _____
Industry _____	Process unit _____

Light type (fluorescent, incandescent, natural _____

Light location (overhead, behind observer, etc.) _____

Illuminance (lux or footcandles) _____

Sketch process unit; indicate observer position relative to source; indicate potential emission points and/or actual emission points.

OBSERVATIONS	Clock time	Observation period duration, min:sec	Accumulated emission, time, min:sec
Beginning observation			
End observation			

Figure 22-2

federal register

Tuesday
October 18, 1983

Part IV

Environmental Protection Agency

Standards of Performance for New Sources; Pressure Sensitive Tape and Label Surface Coating Industry

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2224-6]

Standards of Performance for New Sources; Pressure Sensitive Tape and Label Surface Coating Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for the pressure sensitive tape and label surface coating industry were proposed in the Federal Register on December 30, 1980 (45 FR 86278). This action promulgates a standard of performance to limit emissions of volatile organic compound (VOC) from new, modified, and reconstructed pressure sensitive tape and label coating lines. This standard implements Section 111 of the Clean Air Act and is based on the Administrator's determination that industrial paper coating facilities contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Pressure sensitive tape and label manufacturing is one of the largest contributors to air pollution in the industrial paper coating category. The intended effect of the standard is to require all new, modified, and reconstructed pressure sensitive tape and label surface coating lines to use the best demonstrated system of continuous emissions reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: October 18, 1983.

Under Section 307(b)(1) of the Clean Air Act, judicial review of this new source performance standard is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under Section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESS: **Background Information Document.** The background information document (BID) for the promulgated standard may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Pressure Sensitive Tape and Label Surface Coating Industry—Background Information for Promulgated Standards" (EPA 450/3-80-003b). The BID contains: (1) A summary of all of the public comments made on the proposed standards and the Administrator's response to the comments; and (2) a summary of the changes made to the regulation since proposal. The final environmental impact statement which summarizes the impacts of the standard is included in "Pressure Sensitive Tape and Label Surface Coating Industry—Background Information for Promulgated Standards" (EPA 450/3-80-003b). The environmental impacts have not changed since proposal.

Docket. Docket number A-79-38, containing information considered by EPA in the development of the promulgated standard, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), West Tower Lobby, Gallery 1, 401 M Street, SW, Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Fred Porter, Section Chief, Standards Development Branch, Emissions Standard and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5578.

SUPPLEMENTARY INFORMATION: OMB Control Number: 2060-0004.

The Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emissions reduction which (taking into consideration the cost of achieving such emissions reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or BDT.

The promulgated standard applies to each new, modified, and reconstructed pressure sensitive tape and label coating line for which construction is commenced after December 30, 1980. A coating line consists of any number or combination of adhesive, release, or precoat coating applicators, flashoff areas, and drying ovens which coat a continuous web, located between a web unwind station and a web rewind station, to produce pressure sensitive tapes and labels. Each coating line constitutes the affected facility for the purposes of this standard.

Under the standard, emissions from an affected facility would be limited to 0.20 kilograms of volatile organic compounds (VOC) per kilogram of coating solids applied to the substrate material, as measured by EPA Reference Methods 24 and 25 [promulgated in the Federal Register on October 3, 1980 (45 FR 65956)]. As an alternative, the owner or operator of the affected facility may demonstrate either a 90 percent overall VOC emissions reduction or an overall emissions reduction which is equivalent to the 0.20 kilograms per kilogram of coating solids applied level, whichever is less stringent. This overall emissions reduction is based on the amount of solvent applied with the coating solids.

In establishing the standard, EPA accounted for emissions from startups and shutdowns, which are normal occurrences and hence representative conditions for this source category. As a result, all data obtained during the performance test is to be used in calculating removal efficiency, except for data obtained during malfunction of a control device. In this instance only, data may be discarded provided the source demonstrates that a malfunction occurred and also demonstrates that any discarded data is clearly attributable to the malfunction. Compliance will then be determined on all remaining data.

Compliance with the standard can be determined over a calendar month averaging period by Reference Method 24 or by manufacturer's data. For coating lines which are controlled by incineration systems, Reference Method 25 or an approved alternative method will be used for performance testing.

Coating lines which input to the coating process 45 Mg (50 tons) of VOC or less per 12 month period are not subject to the emission limits of the proposed standard, but are subject to the recordkeeping requirements of the standard. If the 12 month limit stated above is exceeded, the affected facility becomes subject to the emission limits and all other requirements of the standard.

Compliance with the standard may be achieved through either the addition of control equipment to the facility, such as carbon absorption or thermal incineration, or through the use of low-solvent coatings in the production process. Certain coatings currently in use in the pressure sensitive tape and label surface coating industry, including hot melt and waterborne adhesive coatings, as well as 100 percent solid and waterborne release coatings would comply with the standard without the addition of control equipment because

they contain less than 0.20 kilograms of solvent per kilogram of coating solids applied.

The standard requires the owners or operators of pressure sensitive tape and label coating facilities to submit semiannual reports of instances in which the temperature fluctuations of an incinerator control device and the VOC emissions from an affected facility exceed the allowable levels established in the standard. This requirement may be waived in States where the program has been delegated, if EPA, in the course of delegation, approves reporting requirements or an alternative means of source surveillance adopted by the State. Such sources are required to comply with the requirements adopted by the State.

Information collection requirements contained in this regulation (Section 60.447) have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060–0004.

Summary of Environmental, Energy and Economic Impacts

In determining the environmental impacts which will result from the new source performance standard for the pressure sensitive tape and label surface coating industry, EPA established as a baseline for analytical purposes the level of emissions reduction identified in the control techniques guideline (CTG) document for this industry entitled "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coil, Paper, Fabrics, Automobiles, and Light-Duty Trucks" [EPA 420/2–77–008(CTG)]. Although States are not required to adopt the emission limits and control techniques recommended in this document, they are the limits and techniques most likely to be instituted in the State implementation plans (SIP's).

Compared to this baseline, the national emissions of VOC from the pressure sensitive tape and label surface coating industry would be further reduced by 16 percent in 1985. Annual emissions of VOC from affected facilities would be reduced by 9,500 megagrams (10,600 tons) in 1985.

Other environmental impacts of the application of the standard to the pressure sensitive tape and label surface coating industry would be reasonable in light of the gains in emissions reduction being achieved through the standard. National wastewater discharges from the industry would increase by 13 percent over the discharges occurring under baseline controls resulting in an annual increase in discharges of about 2.5 million liters (661,000 gallons) in 1985. The generation of solid waste from an affected facility would be increased slightly in relation to the present generation of large quantities of flawed product and discarded packing materials and spools which are disposed of as solid waste. The only addition to this material from an affected facility is spent activated carbon from carbon adsorption units. Under this standard, the maximum increase in solid waste generated by affected facilities on a nationwide basis is expected to be 55 megagrams (60 tons) per year in 1985.

The national energy impact of the standard is dependent upon which of three control scenarios are followed by the industry in complying with this standard. The use of low-solvent coatings for VOC emissions control would result in no energy impact from this standard, since this method would involve no additional control technology or loss of solvent. However, since EPA is unable to predict the extent to which this technology will be employed by the industry, this analysis focused on the two other technological controls capable of meeting the standard—carbon adsorption and incineration. Based on an analysis of the industry during the development of the standard, the majority of plants using VOC emission control devices used carbon adsorption instead of incineration. It has been estimated that 80 percent of the control systems to be installed by 1985 will be carbon adsorption. The energy impacts associated with this standard will be more closely approximated by the figures given for carbon adsorption controls.

The substantial use of carbon adsorption controls would result in a net energy savings because usable solvent would be recovered from the process. These net savings would be the equivalent of 27,100 barrels (4.3 million liters) of crude oil per year in 1985 if all affected facilities used carbon adsorption. The use of incineration controls by some facilities (approximately 20 percent) will reduce the potential energy savings achievable below the 27,100 barrel figure since this technique recovers no solvent. However, the efficient use of heat recovery by incinerator users will enable an overall net energy savings to be maintained.

The situation of all or the majority of affected facilities using incineration to control VOC emissions is not expected. If incineration did become the predominant control technique a potential energy demand of 31,000 barrels (8.9 million liters) of crude oil could result. However, for practicality and energy efficiency incinerator users would perform some degree of heat energy recovery such that the energy demand would realistically be much less than 31,000 barrel figure. The use of primary and secondary heat recovery by a large number of facilities could even result in a net energy savings. Under both the probable and worst case situations the energy impacts of the standard are reasonable.

EPA has analyzed the effect of the standard on a wide range of model facilities of varying sizes and production capacities. Both the capital and annualized costs of compliance were found to be reasonable except for coating lines which input to the coating process 45 Mg (50 tons) or less per 12 month period. The 45 Mg (50 tons) per 12 month period or less lines have been exempted from compliance with the emission limits of the standard.

Incremental compliance costs are those incurred by a plant above what is normally required of the facility under a typical SIP regulation. For example, a typical affected facility with a 1.5 meter (60 inch) wide coating line would be projected to incur approximately $300,000 in incremental capital expenditures for control equipment. Incremental annualized costs in 1985 for emissions control would be $43,000 for carbon adsorption, while incineration would result in a cost savings of about $8,000. These costs were calculated assuming a 50 percent credit value for usable solvent or heat recovery.

The incremental cumulative capital cost of compliance to the tape and label industry in 1985 would be $12.5 million. The annualized cost of compliance to the industry in 1985, including capital costs (interest and depreciation), would be $1.7 million over the baseline costs. This annualized cost was also determined assuming a 50 percent credit value for solvent/heat recovery.

Further economic impact of the standard on the pressure sensitive tape and label surface coating industry is expected to be minimal. A product price increase of 0.9 percent would be expected in order to allow the industry to recover the cost of compliance with the standard and the installation of control equipment. The effects of this standard on growth in the industry, and industry structure and profitability would not cause significant inflationary impacts or market withdrawals.

The environmental, energy, and economic impacts are discussed in greater detail in the background information document for the promulgated standards, "Pressure Sensitive Tape and Label Surface

Coating Industry—Background Information for Promulgated Standards" (EPA 450/3–80–003b).

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical SIP. They establish a degree of national uniformity, which precludes situations in which some States may attract new industries as a result of having relaxed air pollution standards relative to other States. Further, standards of performance provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies, development of associated costs, an evaluation and verification of applicable emission test methods, and identification of specific emission limits achievable with alternative technologies. The costs are provided for an economic analysis that reveals the affordability of controls in an unbiased study of the economic impact of controls on an industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** on November 14, 1979 (44 FR 65670) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the new source performance standard for the pressure sensitive tape and label surface coating industry recommended for proposal. This meeting was held on December 13, 1979. The meeting was open to the public and each attendee was given the opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the **Federal Register** on December 30, 1980 (45 FR 86278). The preamble to the proposed standards discussed the availability of the background information document (BID) "Pressure Sensitive Tape and Label Surface Coating Industry—Background Information for Proposed Standards" (EPA–450/3–80–003a), which described in detail the regulatory alternative considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on January 30, 1981 at Research Triangle Park, North Carolina. The hearing was open to the public and each attendee was given an opportunity to comment on the proposed standards. The public comment period was from December 30, 1980 to March 2, 1981.

Fourteen comment letters were received and two interested parties testified at the public hearing concerning issues relative to the proposed standards of performance for the pressure sensitive tape and label surface coating industry. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standard.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from industry, two members of Congress, one State pollution control agency, and one trade association. A detailed discussion of these comments and responses can be found in the background information document (BID) which is referred to in the **ADDRESS** section of this preamble. The summary of comments and responses in the BID serve as the basis for the revisions which have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The comments have been divided into the following areas: General, Emission Control Technology, Modification and Reconstruction, Economic Impact, Affected Facility Definition, Reporting and Recordkeeping, Small Source Exemption, Level of the Proposed Standard, and NSPS and State Implementation Plan (SIP) Coordination.

General

One commenter pointed out that the discussion of solventless technologies in the BID did not reflect the latest improvements in such technologies which, although not in common use in the United States, are being used in Europe. The technological variations discussed by this commenter were considered in the development of the BID and this standard, but were determined not to add significantly to the standard. Upon further consideration, the technological configuration discussed by this commenter might offer advantages to the industry in reducing VOC emissions, and the promulgation and operation of the standard will not adversely affect the use of such technology.

Another commenter discussed the application of the standard to radiation-cured coatings, asking that they either be exempted from the standard or that analytical methods be revised to accommodate the characteristics of this process. It was determined that radiation-cure coating processes do not involve coatings containing VOCs, and therefore the processes would fall below the standard of 0.20 kilograms of VOC per kilogram of coating solids without requiring further controls.

Another commenter objected to the inclusion of water in water-based coatings as a part of the emissions to be measured in determining whether the facility is subject to the standard. This is an apparent misunderstanding of the provisions of the standard. The standard does not include water in the calculation of VOC emissions.

Another commenter objected to certain commenter objected to certain conclusions stated in the background information document concerning the level of inlet VOC concentration required to operate an incinerator for the control of VOC emissions without the necessity of adding supplementary fuel to the incinerator. This objection was based on the results of tests performed on the commenter's own incinerator in 1972 which varied from the results reported in EPA's analysis. The level reported in the BID is based on a model incinerator designed to represent the typical incinerator used for VOC control in the PSTL industry and is intended to indicate the trends in incinerator performance as various loadings of solvent are added to the incinerator. Therefore, variance between the results reported for this representative model incinerator study and for other tests on individual incinerators is to be expected (see Section 2.1.4 of the BID for further discussion).

Several commenters in this section stated that no standard is necessary since there is already adequate economic incentive for the users of coatings containing VOC to recover the maximum amount of solvent possible for reuse. Although the Administrator viewed these economic incentives as important to the overall operation and success of the standard, an examination of the industry indicates that economic incentives alone are not sufficient to ensure that the pressure sensitive tape and label surface coating industry will use the best demonstrated technology for the control of VOC emissions. Indeed, during the examination of these facilities leading to the development of this standard, it was noted that in spite of these incentives, some facilities did

not recover any solvent from their coating operations.

Emission Control Technology

One commenter stated that the use of hooding to capture fugitive VOC emissions from coating heads has not been demonstrated except on a theoretical basis. During the development of this standard, EPA examined a facility which employed hooding to capture fugitive emissions. Based on tests performed at this facility and observation of other facilities employing hooding for the capture of fugitive emissions, the Administrator has determined that hooding is an effective device for capturing these emissions and that compliance with the standard can be achieved employing this technology and add-on control devices.

Modification and Reconstruction

Several comments were received concerning the application of the modification and reconstruction provisions of the General Provisions of 40 CFR Part 60 to this standard for the pressure sensitive tape and label surface coating industry. One stated that these provisions were vague and subject to misinterpretation. Experience with these provisions and examination of their applicability to this industry indicates that problems with interpreting when a facility has been modified or reconstructed and thereby made subject to the standard should be minimal. The modification provisions establish a fairly straightforward rule that when an alteration to a facility results in an increase in emissions the facility is then subject to the standard, unless the alteration falls within certain specifically listed exemptions. The reconstruction provision involves a plant specific review by the Agency to determine whether a major expenditure at a facility should include the provisions of the control technology required for compliance with the standard. Although the operation of this provision involves the application of judgment to the circumstances of the alteration, it also provides for the inclusion of a greater variety of factors, such as the economic impact of the standard, in determining whether the facility will be subject to the standard.

Two comments were received concerning the applicability of the modification and reconstruction provisions to specific alterations to a facility. The first comment questioned whether normal repairs to a facility constitutes a modification. The applicable sections of the modification provisions state that normal repairs to a facility do not constitute modifications which would render a facility subject to the standard. The second comment concerned the application of the standard to a facility which converts to solventless or low-solvent coatings. This case would not constitute a modification of the facility, since there would be no increase in emissions from the facility. Whether such a conversion would constitute a reconstruction would involve a calculation of whether the cost of the conversion was greater than 50 percent of the cost of an entirely new plant, and then involve an additional review of the circumstances of the conversion by the Administrator before the applicability of the standard to the facility could be determined.

A final commenter stated generally that the standard should not be made applicable to a facility which undergoes updating and modification because this will result in outdated and less efficient plants being left in operation for a longer period of time. While it is true that the effect of the standard will enter into decisions concerning the updating of plants, the savings in energy and efficiency resulting from improvements to the facility are expected to be overriding considerations in this decision. Therefore, the application of the standard to pressure sensitive tape and label surface coating facilities which undergo extensive alteration is consistent with the scheme of the Clean Air Act.

Economic Impact

One commenter on the economic analysis performed in the development of the standard objected that the cost figures reported in the BID (Volume I) were not consistent with current values. The values listed in the BID, and the basis of the analysis performed there, were based on 1979 figures. Although these figures may change in time, they remain consistent in relation to each other and do not change the validity of the conclusions reached in the analysis concerning the reasonableness of the standard. If converted into current cost figures and reanalyzed, the relations of cost to the achievements of the standard would remain the same. Therefore, it is the relationship between the figures, and not their absolute accuracy for all points in time, that is crucial to the analysis of the economic impact of the standard.

Another commenter stated that the added costs of pollution control required by the standard would be passed on to consumers, resulting in an inflationary impact on the economy. EPA's analysis, however, shows that even with full pass-through of the costs to the consumer the maximum product price increase would be 0.9 percent. This mimimal cost increase is considered by the Administrator to be reasonable and noninflationary.

In several comments, objections were made to the standard on the basis of the minimal reduction in emissions which would be achieved under the standard as compared to existing State regulations as compared to the greatly increased cost of compliance with the standard. These reductions and costs were analyzed by the EPA in the BID. It was determined that by 1985 emissions from pressure sensitive tape and label surface coating facilities would be reduced by 16 percent per year as compared to the controls required by existing regulations. The increase in product price necessitated by this 16 percent reduction in emissions would be less than 1 percent. Therefore, the additional emissions reduction seems well justified in terms of the costs required for achieving them.

The effect of the standard on the conversion of the industry to solventless and low-solvent technologies was also the subject of one comment. This commenter was concerned that the costs of complying with the standard would cause owners of facilities to forego conversion. However, low-solvent and solventless technologies are treated essentially equally under the standard and under existing regulations, since they typically are able to comply with the standard without the necessity of further add-on controls. In addition, it is believed that economic factors outside of the operation of this standard, such as the cost and availability of solvents, will provide additional incentive for the conversions of coating lines to low-solvent and solventless costing technologies.

Four commenters stated that the economic analysis performed by EPA was insufficient, particularly with relation to small facilities. Chapter 8 of the BID contains this ecomonic analysis, which is directed specifically to small facilities as well as large and medium facilities. Model coating lines of all three sizes and various technological characteristics were analyzed and the impact of the standard on each determined in the development of the standard. This analysis is necessarily representative rather than exhaustive of each facility in the industry, but does accurately reflect the standard and its impact on the industry.

A final commenter in this segment stated that the standard should only be applied on a case-by-case basis after analyzing the costs and benefits of the additional control to each individual

plant. Section 111 of the Clean Air Act does not provide for case-by-case application of a standard but instead requires that the standard be applied to the entire source category or to distinguishable subgroups within that category. In addition, it is not expected that the impact of this standard on any individual plant will vary from the models used in the development of the standard to the extent that the impact of the standard would be unreasonable.

Affected Facility Definition

The Administrator has determined that the definition of affected facility proposed for inclusion in the standard should be changed in response to comments made on this issue by several commenters and upon further consideration by the Agency.

As explained in the preamble to the proposed standard, EPA adopts that definition of affected facility which produces the greatest emission reduction without imposing unreasonable costs or other impacts. The original definition proposed for this industry provided that each separate coating head and drying oven combination along a coating line would constitute an affected facility for the purpose of this standard. Thus, there would be more than one affected facility associated with each coating line, each of which would be required to comply with the standard. Several commenters urged the Agency to amend this definition to make the affected facility, for the purposes of this standard, the entire coating line, including all individual coating heads and drying ovens. Under this definition, the combination of sources along a coating line would be required to comply with the standard, rather than each individual source.

In urging this change, the commenters made several points. First, they argued that the coating line is the basic production unit for the industry and marks the most logical unit for control in terms of the configuration of the production processes and plants. In support, they pointed out that the various State implementation plans (SIP's) under which they operate consider the coating line to be the basic unit for control, not each coating head and oven combination. Secondly, they argued that this broader definition would allow the operators of facilities to control their emissions in the most cost effective manner. By grouping these emission sources together under one overall requirement, the owner or operator of the facility may control these sources where the greatest reduction may be achieved at the lowest cost and minimize expenditures for emissions control where the benefits in reductions would be small. Finally, they pointed out that the broader definition covering the entire coating line would promote the development and use of low-solvent and solventless technologies as emissions control techniques, resulting in an overall betterment in air quality beyond that achievable by the standard and technological requirements alone. In support of this position, new data were submitted by the industry showing that the relative costs of low-solvent compared to solvent-based adhesive coating technology have changed since EPA's BID was prepared. These data show that low-solvent technology is more limited in application than the EPA and industry had previously anticipated and that the cost is higher than the current cost of comparable solvent-based systems.

After reviewing these comments and the two definitions, the Administrator determined that in light of the similar degree of overall emissions reduction achievable under either definition, the greater flexibility in allocating control costs available under the broadened definition, and the physical compatibility of the broadened definition with the characteristics of the pressure sensitive tape and label surface costing production line, the affected facility definition should be amended to provide for the inclusion of the entire coating line. The Administrator believes that the broad definition will encourage the use of low-solvent and solventless adhesive coatings, and achieve an equal or greater emission reduction than the narrow definition. When the standard is reviewed in four years as required under Section 111(b) of the Act, the low-solvent and solventless adhesive technology will be closely evaluated.

Reporting and Recordkeeping

Several commenters objected to the reporting and recordkeeping requirements of the standard, stating that these requirements are costly and burdensome. They further contended that these requirements would hinder the development and adoption of innovative coating technologies by the industry by requiring facilities to keep records and make reports even though the characteristics of their coatings bring them within the limits set by the standard without technological controls.

The Administrator has reviewed the recordkeeping and reporting requirements of the proposed standard, and determined that those requirements calling for reports to be submitted to the Agency should be modified in the promulgated standard. Reporting requirements in the promulgated standard have been reduced to only requiring semiannual reports of instances when the temperature fluctuations of an incinerator control device and the VOC emissions from an affected facility exceed the allowable levels established in the standard. In the proposed standard such reports were required on a calendar month basis. The other reporting requirement in the proposed standard for the submittal of initial (and any subsequent) performance test results to the Administrator remains unchanged in the promulgated standard.

The compiling and keeping of records of the performance of the control equipment installed in compliance with this standard is necessary, both to the Agency in determining compliance and to the company operating the facility to determine whether the control equipment is functioning adequately. The recordkeeping requirements therefore have not been changed since proposal. In order to determine compliance with the standard, the Agency may inspect the records kept by a facility at any time.

Small Solvent Use Exemption

One commenter urged the Agency to include an exemption for small sources in the standard, raising the minimum levels of emissions for inclusion under the regulation from 15 megagrams per year to an unspecified higher level. The reasons stated by this commenter in support of the change were that small sources comprise a minor part of the total VOC emissions for the entire industry, that the cost of emissions control for small sources is unreasonable for the benefits in emissions reduction achieved, and that a small source exemption would encourage the development of low-solvent and solventless coatings. In analyzing this issue, the Administrator has determined that a broadened small source exemption is not warranted on the bases of contributing a minor part to total industry emissions or the failure of the standard to encourage the development of low-solvent or solventless coatings. Section 111 requires new source performance standards to reflect the best demonstrated technology. It does not provide a basis for exempting subcategories of sources (for which control technology is technically and economically available) from any standard merely because their emissions are less than the emissions of other subcategories. Further, it has been

determined by the Administrator that this standard will not impede the conversion to and development of solventless and low-solvent technologies.

However, the Agency has reanalyzed the cost effectiveness (i.e., the cost of VOC emissions control relative to the emission reduction which is achieved by such controls) over the range of line sizes found in this industry. For each type of line, annualized control costs were calculated and compared to the emission reductions which would occur if potential, uncontrolled emissions are reduced to the level of the standard. This analysis showed that the cost effectiveness of controls is primarily a function of the quantity of solvent used, and that the parameters are inversely related. That is, as solvent use (and therefore potential emissions) increases, the cost effectiveness decreases. It should be noted that this cost curve does not necessarily represent the actual amounts of money that will be spent to install and operate VOC controls for any particular coating line. Rather, the costs are estimates which are representative of facilities likely to be built. The costs for a VOC control system will vary according to coating line size, system airflow rate, solvent loading level, the lower explosive limit levels maintained in the oven, the degree of solvent or heat recovery practiced, and other factors. However, the cost curve provides a useful guide for judging the reasonableness of requiring VOC controls at different potential VOC emission levels.

In the past, the maximum estimated cost per megagram of pollutant material removed (VOC, particulate matter, SO_2) has ranged from somewhat less than $1,000 to $2,000. This package has a maximum estimated cost per megagram of $2,000. In prior source categories for which NSPS have been developed, VOC maximum estimated control costs have generally not exceeded $1,000 per megagram. In this case, because of the "worst-case" character of the cost calculations, EPA believes the proposed standards are reasonable.

The maximum estimated cost in this package will not be viewed as a precedent for future actions. Instead, in the future, we will continue to evaluate each package on an individual basis.

The cost curve for the application of VOC controls to coating lines shows that the potential cost per Mg of VOC controlled is greater than $2,000 for input solvent levels of about 45 Mg (50 tons) per year or less. Therefore, in the promulgated standard, coating lines which input to the coating process 45 Mg (50 tons) per 12 month period or less of VOC will not be subject to the standard's emission limits. These lines will, however, be subject to all applicable recordkeeping and reporting requirements given in the standard.

The Agency realizes that this exemption could inadvertently create an incentive for the construction of smaller lines in order to avoid the need for VOC emissions control. The Agency does not believe, however, that this incentive is sufficient to markedly alter the construction pattern of new PSTL lines such that national VOC emissions would be greatly increased. However, this standard will be reviewed four years from now, and the effect of the small solvent-use exemption on the size of new facilities will specifically be examined.

Level of Proposed Standard

One commenter stated that the 90 percent reduction level in the standard seemed to be arbitrary. On the contrary, the 90 percent reduction level was developed through extensive study and analysis of the pressure sensitive tape and label surface coating industry, the available emissions control equipment, and the environmental, energy and economic impacts of various control levels. It was determined that the best demonstrated control technology could continually achieve a 90 percent reduction in emissions over a long term period of operation. The analyses of the technological systems of emissions control are contained in Chapter 4 of the BID—Volume I, and the energy, environmental, and economic impacts of these technologies are discussed in Chapters 7 and 8 of the BID— Volume I.

Another commenter stated that a turndown ratio of 10 to 1 could not be achieved in drying oven exhausts, as stated in the BID. (Turndown ratio refers to the degree by which oven exhaust air can be reduced from the level for which the oven is designed in response to reduced solvent loadings.) In its examination of this issue, the Agency has determined that the technical points made by this commenter are generally valid (particularly for his own plant, on which his comments were based), but that new facilities are still capable of achieving compliance with the standard on a consistent basis even with a lower turndown ratio, such as the four to one ratio cited by the commenter. This determination is based on the experience of other facilities examined by the Agency during the course of the development of this standard which were able to meet the reduction level required by the standard even at the lower turndown ratios. This analysis is presented in detail in Volume I of the BID.

A third commenter on the issue of the level of the standard stated that the mass emission limit should be 0.25 kilograms of VOC per kilogram of coating solids, rather than 0.20 kilograms, in order to allow a wider range of low-solvent coatings to be used without requiring the use of additional control technology in order to comply with the standard. The EPA examined a number of solventless and low-solvent coatings during the preparation of this standard. It was determined that a 0.20 kilogram emission limit could be attained using the best technological system of emissions reduction (consistent with energy, environmental, and economic considerations). No comments were received which presented argument or data contradicting this determination. Although there will be some new coatings which cannot be used without further controls in compliance with the standard, these coatings may still be useful in combination with other coatings in achieving the emissions reduction required. If used with other low-solvent coatings on a line, coatings capable of achieving 0.25 kilograms of VOC per kilogram of coating solid could help keep the monthly compliance average below 0.20 kilograms. If used with conventional solvent based coatings, these coatings would reduce the level of control necessary to achieve compliance with the standard.

NSPS and SIP Coordination

Two commenters suggested that the implementation of the standard be postponed for a 5 to 10 year period in order to assess the impact on air quality of the newest limits recommended for State implementation plans (SIP's) of 2.9 pounds of VOC per gallon of applied coating. During the development of the standard, this SIP requirement was examined and its impact on national VOC emissions projected. Further, this SIP requirement formed the baseline against which each of the regulatory alternatives has been evaluated. Therefore, no further delay in the promulgation of this standard is required in order to determine the impact of the SIP provisions since these impacts have been projected and formed a major consideration in the development of the standard.

The last two commenters in this section pointed out that the units of measurement in the standard (kg VOC/kg coating solids) are different from these used in many of the SIP's (pounds, gallon of coating minus water), and that

this difference would be confusing to owners and operator of facilities which must attempt to comply with both the new source standard and a SIP. The unit of measurement used in this standard was developed through consultation with industry representatives who pointed out that companies have experienced difficulties in interpreting and implementing the mass per volume measurement used in the SIP's. The mass measurement used in this standard was found to be simpler to understand and to calculate from typical coating formulation data. Further, there should be no confusion over compliance with different standards which may apply to a facility since compliance with the more stringent in each case also satisfies the requirements of the less stringent. In this case, compliance with the 0.20 kilograms VOC per kilogram of coating solid new source standard would also constitute compliance with a 2.9 pounds VOC per gallon requirement of a SIP.

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review [Section 307(d)(7)(A)].

Miscellaneous

The effective date of this regulation is October 18, 1983. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (December 30, 1980).

As prescribed in Section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well-publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in this regulation will be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to insure that cost was carefully considered in determining BDT. The economic impact assessment is included in the background information document for the proposed standards.

In addition to conducting an economic impact analysis, EPA examined the emission reduction and annualized costs, expressed in dollars per Mg (ton) of pollutant removed per year, for three alternative levels of control. The three levels of control are an overall emissions reduction of 81 percent, as specified in many existing SIP's; an overall emissions reduction of 85 percent; and an overall emissions reduction of 90 percent, as required by the NSPS. This examination showed that for a typical medium-sized pressure sensitive tape and label surface coating line an 85 percent level of control reduces emissions by 41 Mg (45 tons) per year relative to the 81 percent level (SIP level) and increases annualized costs by $145/Mg ($130/ton). It also showed that the incremental emission reduction achieved by increasing the control level from 85 to 90 percent is (38 tons) at an incremental annualized cost of $115/Mg ($105/ton). These annualized costs per ton of pollutant removed are comparable to costs and associated emissions in other industries that control VOC emissions. In addition, as described in the section "Small Solvent Use Exemption," the Agency also analyzed the overall cost effectiveness of adding controls to uncontrolled lines and on the basis of this established a low solvent use cut-off.

The Paperwork Reduction Act of 1980 (Pub. L. 96-511) requires EPA to submit to the Office of Management and Budget (OMB) certain public reporting/recordkeeping requirements. The reporting/recordkeeping requirements associated with this standard have been approved by OMB.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because it would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be major. The industry-wide annualized costs in the fifth year after the standards would go into effect would be $1.7 million, much less than the $100 million established as the first criterion for a major regulation in the Order. The estimated price increase of less than 2 percent associated with the standards would not be considered a "major increase in costs or prices" specified as the second criterion in the Order. The economic analysis of the standards' effects on the industry did not indicate any significant adverse effects on competition, investment, productivity, employment, innovation, or the ability of the U.S. firms to compete with foreign firms (the third criterion in the Order).

Information collection requirements contained in this regulation (§§ 60.443, 60.444, 60.445, and 60.447) have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060-0004.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic Minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel

Sulfuric acid plants. Waste treatment and disposal. Zinc. Tires. Incorporation by reference. Can surface coating. Sulfuric acid plants. Industrial organic chemicals.

Dated: October 11, 1983.

William D. Ruckelshaus,

Administrator.

PART 60—[AMENDED]

40 CFR Part 60 is amended by adding a new Subpart RR as follows:

Subpart RR—Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations

Sec.

60.440 Applicability and designation of affected facility.
60.441 Definitions and symbols.
60.442 Standard for volatile organic compounds.
60.443 Compliance provisions.
60.444 Performance test procedures.
60.445 Monitoring of operations and recordkeeping.
60.446 Test methods and procedures.
60.447 Reporting requirements.

Authority: Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart RR—Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations

§ 60.440 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each coating line used in the manufacture of pressure sensitive tape and label materials.

(b) Any affected facility which inputs to the coating process 45 Mg of VOC or less per 12 month period is not subject to the emission limits of § 60.442(a), however, the affected facility is subject to the requirements of all other applicable sections of this subpart. If the amount of VOC input exceeds 45 Mg per 12 month period, the coating line will become subject to § 60.442(a) and all other sections of this subpart.

(c) This subpart applies to any affected facility which begins construction, modification, or reconstruction after December 30, 1980.

§ 60.441 Definitions and symbols.

(a) Except as otherwise required by the context, terms used in this subpart are defined in the Act, in Subpart A of this part, or in this section as follows:

"Coating applicator" means an apparatus used to apply a surface coating to a continuous web.

"Coating line" means any number or combination of adhesive, release, or precoat coating applicators, flashoff areas, and ovens which coat a continuous web, located between a web unwind station and a web rewind station, to produce pressure sensitive tape and label materials.

"Coating solids applied" means the solids content of the coated adhesive, release, or precoat as measured by Reference Method 24.

"Flashoff area" means the portion of a coating line after the coating applicator and usually before the oven entrance.

"Fugitive volatile organic compounds" means any volatile organic compounds which are emitted from the coating applicator and flashoff areas and are not emitted in the oven.

"Hood or enclosure" means any device used to capture fugitive volatile organic compounds.

"Oven" means a chamber which uses heat or irradiation to bake, cure, polymerize, or dry a surface coating.

"Precoat" means a coating operation in which a coating other than an adhesive or release is applied to a surface during the production of a pressure sensitive tape or label product.

"Solvent applied in the coating" means all organic solvent contained in the adhesive, release, and precoat formulations that is metered into the coating applicator from the formulation area.

"Total enclosure" means a structure or building around the coating applicator and flashoff area or the entire coating line for the purpose of confining and totally capturing fugitive VOC emissions.

"VOC" means volatile organic compound.

(b) All symbols used in this subpart not defined below are given meaning in the Act or in Subpart A of this part.

"a" means the gas stream vents exiting the emission control device.

"b" means the gas stream vents entering the emission control device.

"C_{aj}" means the concentration of VOC (carbon equivalent) in each gas stream (j) exiting the emission control device, in parts per million by volume.

"C_{bi}" means the concentration of VOC (carbon equivalent) in each gas stream (i) entering the emission control device, in parts per million by volume.

"C_{fk}" means the concentration of VOC (carbon equivalent) in each gas stream (k) emitted directly to the atmosphere, in parts per million by volume.

"G" means the calculated weighted average mass (kg) of VOC per mass (kg) of coating solids applied each calender month.

"M_{ci}" means the total mass (kg) of each coating (i) applied during the calendar month as determined from facility records.

"M_r" means the total mass (kg) of solvent recovered for a calendar month.

"Q_{aj}" means the volumetric flow rate of each effluent gas stream (j) exiting the emission control device, in dry standard cubic meters per hour.

"Q_{bi}" means the volumetric flow rate of each effluent gas stream (i) entering the emission control device, in dry standard cubic meters per hour.

"Q_{fk}" means the volumetric flow rate of each effluent gas stream (k) emitted to the atmosphere, in dry standard cubic meters per hour.

"R" means the overall VOC emission reduction achieved for a calendar month (in percent).

"R_q" means the required overall VOC emission reduction (in percent).

"W_{oi}" means the weight fraction of organics applied of each coating (i) applied during a calendar month as determined from Reference Method 24 or coating manufacturer's formulation data.

"W_{si}" means the weight fraction of solids applied of each coating (i) applied during a calendar month as determined from Reference Method 24 or coating manufacturer's formulation data.

§ 60.442 Standard for volatile organic compounds.

(a) On and after the date on which the performance test required by § 60.8 has been completed each owner or operator subject to this subpart shall:

(1) Cause the discharge into the atmosphere from an affected facility not more than 0.20 kg VOC/kg of coating solids applied as calculated on a weighted average basis for one calendar month; or

(2) Demonstrate for each affected facility;

(i) a 90 percent overall VOC emission reduction as calculated over a calendar month; or

(ii) the percent overall VOC emission reduction specified in § 60.443(b) as calculated over a calendar month.

§ 60.443 Compliance provisions.

(a) To determine compliance with § 60.442 the owner or operator of the affected facility shall calculate a weighted average of the mass of solvent used per mass of coating solids applied for a one calendar month period according to the following procedures:

(1) Determine the weight fraction of organics and the weight fraction of solids of each coating applied by using Reference Method 24 or by the coating manufacturer's formulation data.

(2) Compute the weighted average by the following equation:

$$G=\frac{\sum_{i=1}^{n} W_{oi}M_{oi}}{\sum_{i=1}^{n} W_{oi}M_{oi}}$$

(3) For each affected facility where the value of G is less than or equal to 0.20 kg VOC per kg of coating solids applied, the affected facility is in compliance with § 60.442(a)(1).

(b) To determine compliance with § 60.442(a)(2), the owner or operator shall calculate the required overall VOC emission reduction according to the following equation:

$$R_q=\frac{G-0.20}{G}\times 100$$

If R_q less than or equal to 90 percent, then the required overall VOC emission reduction is R_q. If R_q is greater than 90 percent, then the required overall VOC emission reduction is 90 percent.

(c) Where compliance with the emission limits specified in § 60.442(a)(2) is achieved through the use of a solvent recovery system, the owner or operator shall determine the overall VOC emission reduction for a one calendar month period by the following equation:

$$R=\frac{M_r}{\sum_{i=1}^{n} W_{oi}M_{oi}}\times 100$$

If the R value is equal to or greater than the R_q value specified in paragraph (b) of this section, then compliance with § 60.442(a)(2) is demonstrated.

(d) Where compliance with the emission limit specified in §60.442(a)(2) is achieved through the use of a solvent destruction device, the owner or operator shall determine calendar monthly compliance by comparing the monthly required overall VOC emission reduction specified in paragraph (b)1 of this section to the overall VOC emission reduction demonstrated in the most recent performance test which complied with § 60.442(a)(2). If the monthly required overall VOC emission reduction is less than or equal to the overall VOC reduction of the most recent performance test, the affected facility is in compliance with § 60.442(a)(2).

(e) Where compliance with § 60.442(a)(2) is achieved through the use of a solvent destruction device, the owner or operator shall continuously record the destruction device combustion temperature during coating operations for thermal incineration destruction devices or the gas temperature upstream and downstream of the incinerator catalyst bed during coating operations for catalytic incineration destruction devices. For thermal incineration destruction devices the owner or operator shall record all 3-hour periods (during actual coating operations) during which the average temperature of the device is more than 28°C (50°F) below the average temperature of the device during the most recent performance test complying with § 60.442(a)(2). For catalytic incineration destruction devices, the owner or operator shall record all 3-hour periods (during actual coating operations) during which the average temperature of the device immediately before the catalyst bed is more than 38°C (50°F) below the average temperature of the device during the most recent performance test complying with § 60.442(a)(2), and all 3-hour periods (during actual coating operations) during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the device during the most recent performance test complying with § 60.442(a)(2).

(f) After the initial performance test required for all affected facilities under § 60.8, compliance with the VOC emission limitation and percentage reduction requirements under § 60.442 is based on the average emission reduction for one calendar month. A separate compliance test is completed at the end of each calendar month after the initial performance test, and a new calendar month's average VOC emission reduction is calculated to show compliance with the standard.

(g) If a common emission control device is used to recover or destroy solvent from more than one affected facility, the performance of that control device is assumed to be equal for each of the affected facilities. Compliance with § 60.442(a)(2) is determined by the methods specified in paragraphs (c) and (d) of this section and is performed simultaneously on all affected facilities.

(h) If a common emission control device is used to recover solvent from an existing facility (or facilities) as well as from an affected facility (or facilities), the overall VOC emission reduction for the affected facility (or facilities), for the purpose of compliance, shall be determined by the following procedures:

(1) The owner or operator of the existing facility (or facilities) shall determine the mass of solvent recovered for a calendar month period from the existing facility (or facilities) prior to the connection of the affected facility (or facilities) to the emission control device.

(2) The affected facility (or facilities) shall then be connected to the emission control device.

(3) The owner or operator shall determine the total mass of solvent recovered from both the existing and affected facilities over a calendar month period. The mass of solvent determined in paragraph (h)(1) of this section from the existing facility shall be subtracted from the total mass of recovered solvent to obtain the mass of solvent recovered from the affected facility (or facilities). The overall VOC emission reduction of the affected facility (or facilities) can then be determined as specified in paragraph (c) of this section.

(i) If a common emission control devices is used to destruct solvent from an existing facility (or facilities) as well as from an affected facility (or facilities), the overall VOC emission reduction for the affected facility (or facilities), for the purpose of compliance, shall be determined by the following procedures:

(1) The owner or operator shall operate the emission control device with both the existing and affected facilities connected.

(2) The concentration of VOC (in parts per million by volume) after the common emission control device shall be determined as specified in § 60.444(c). This concentration is used in the calculation of compliance for both the existing and affected facilities.

(3) The volumetric flow out of the common control device attributable to the affected facility (or facilities) shall be calculated by first determining the ratio of the volumetric flow entering the common control device attributable to the affected facility (facilities) to the total volumetric flow entering the common control device from both existing and affected facilities. The multiplication of this ratio by the total volumetric flow out of the common control device yields the flow attributable to the affected facility (facilities). Compliance is determined by the use of the equation specified in § 60.444(c).

(j) Startups and shutdowns are normal operation for this source category. Emissions from these operations are to be included when determining if the standard specified at § 60.442(a)(2) is being attained.

(Approved by the Office of Management and Budget under control number 2060-004)

§ 60.444 Performance test procedures.

(a) The performance test for affected facilities complying with § 60.442 without the use of add-on controls shall be identical to the procedures specified in § 60.443(a).

(b) The performance test for affected facilities controlled by a solvent recovery device shall be conducted as follows:

(1) The performance test shall be a one calendar month test and not the average of three runs as specified in § 60.8(f).

(2) The weighted average mass of VOC per mass of coating solids applied for a one calendar month period shall be determined as specified in § 60.443(a)(1) and § 60.443(a)(2).

(3) Calculate the required percent overall VOC emission reduction as specified in § 60.443(b).

(4) Inventory VOC usage and VOC recovery for a one calendar month period.

(5) Determine the percent overall VOC emission reduction as specified in § 60.443(c).

(c) The performance test for affected facilities controlled by a solvent destruction device shall be conducted as follows:

(1) The performance of the solvent destruction device shall be determined by averaging the results of three test runs as specified in § 60.8(f).

(2) Determine for each affected facility prior to each test run the weighted average mass of VOC per mass of coating solids applied being used at the facility. The weighted average shall be determined as specified in § 60.443(a). In this application the quantities of W_{oi}, W_{si}, and M_{si} shall be determined for the time period of each test run and not a calendar month as specified in § 60.441.

(3) Calculate the required percent overall VOC emission reduction as specified in § 60.443(b).

(4) Determine the percent overall VOC emission reduction of the solvent destruction device by the following equation and procedures:

$$R = \frac{\sum_{i=1}^{n} Q_{vi}C_{vi} - \sum_{j=1}^{m} Q_{vj}C_{vj}}{\sum_{i=1}^{n} Q_{vi}C_{vi} + \sum_{k=1}^{p} Q_{fk}C_{fk}} \cdot 100$$

(i) The owner or operator of the affected facility shall construct the overall VOC emission reduction system so that all volumetric flow rates and total VOC emissions can be accurately determined by the applicable test methods and procedures specified in § 60.446(b).

(ii) The owner or operator of an affected facility shall construct a temporary total enclosure around the coating line applicator and flashoff area during the performance test for the purpose of capturing fugitive VOC emissions. If a permanent total enclosure exists in the affected facility prior to the performance test and the Administrator is satisfied that the enclosure is totally capturing fugitive VOC emissions, then no additional total enclosure will be required for the performance test.

(iii) For each affected facility where the value of R is greater than or equal to the value of R_q calculated in § 60.443(b), compliance with § 60.442(a)(2) is demonstrated.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

(Approved by the Office of Management and Budget under control number 2060–0004)

§ 60.445 Monitoring of operations and recordkeeping.

(a) The owner or operator of an affected facility subject to this subpart shall maintain a calendar month record of all coatings used and the results of the reference test method specified in § 60.446(a) or the manufacturer's formulation data used for determining the VOC content of those coatings.

(b) The owner or operator of an affected facility controlled by a solvent recovery device shall maintain a calendar month record of the amount of solvent applied in the coating at each affected facility.

(c) The owner or operator of an affected facility controlled by a solvent recovery device shall install, calibrate, maintain, and operate a monitoring device for indicating the cumulative amount of solvent recovered by the device over a calendar month period. The monitoring device shall be accurate within ±2.0 percent. The owner or operator shall maintain a calendar month record of the amount of solvent recovered by the device.

(d) The owner or operator of an affected facility operating at the conditions specified in § 60.440(b) shall maintain a 12 month record of the amount of solvent applied in the coating at the facility.

(e) The owner or operator of an affected facility controlled by a thermal incineration solvent destruction device shall install, calibrate, maintain, and operate a monitoring device which continuously indicates and records the temperature of the solvent destruction device's exhaust gases. The monitoring device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5° C.

(f) The owner or operator of an affected facility controlled by a catalytic incineration solvent destruction device shall install, calibrate, maintain, and operate a monitoring device which continuously indicates and records the gas temperature both upstream and downstream of the catalyst bed.

(g) The owner or operator of an affected facility controlled by a solvent destruction device which uses a hood or enclosure to capture fugitive VOC emissions shall install, calibrate, maintain, and operate a monitoring device which continously indicates that the hood or enclosure is operating. No continuous monitor shall be required if the owner or operator can demonstrate that the hood or enclosure system is interlocked with the affected facility's oven recirculation air system.

(h) Records of the measurements required in §§ 60.443 and 60.445 must be retained for at least two years following the date of the measurements.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

(Approved by the Office of Management and Budget under control number 2060–0004)

§ 60.446 Test methods and procedures.

(a) The VOC content per unit of coating solids applied and compliance with § 60.422(a)(1) shall be determined by either Reference Method 24 and the equations specified in § 60.443 or by manufacturers' formulation data. In the event of any inconsistency between a Method 24 test and manufacturers' formulation data, the Method 24 test will govern. The Administrator may require an owner or operator to perform Method 24 tests during such months as he deems appropriate. For Reference Method 24, the coating sample must be a one liter sample taken into a one liter container at a point where the sample will be representative of the coating applied to the web substrate.

(b) Reference Method 25 shall be used to determine the VOC concentration, in parts per million by volume, of each effluent gas stream entering and exiting the solvent destruction device or its equivalent, and each effluent gas stream emitted directly to the atmosphere. Reference Methods 1, 2, 3, and 4 shall be used to determine the sampling location, volumetric flowrate, molecular weight, and moisture of all sampled gas streams. For Reference Method 25, the sampling time for each of three runs must be at least 1 hour. The minimum sampling volume must be 0.003 dscm except that shorter sampling times or smaller volumes, when necessitated by process

variables or other factors, may be approved by the Administrator.

(c) If the owner or operator can demonstrate to the Administrator's satisfaction that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks, the Administrator will approve testing of representative stacks on a case-by-case basis.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.447 Reporting requirements.

(a) For all affected facilities subject to compliance with § 60.442, the performance test data and results from the performance test shall be submitted to the Administrator as specified in § 60.8(a) of the General Provisions (40 CFR Part 60 Subpart A).

(b) The owner or operator of each affected facility shall submit semiannual reports to the Administrator of exceedances of the following.

(1) The VOC emission limits specified in § 60.442; and

(2) The incinerator temperature drops as defined under § 60.443(e). The reports required under paragraph (b) shall be postmarked within 30 days following the end of the second and fourth calendar quarters.

(c) The requirements of this subsection remain in force until and unless EPA, in delegating enforcement authority to a State under Section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected sources within the State will be relieved of the obligation to comply with this subsection, provided that they comply with the requirements established by the State.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

[Approved by the Office of Management and Budget under control number 2060-0004]

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Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources; VOC Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL 2258-8]

Standards of Performance for New Stationary Sources; VOC Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standard would limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed air oxidation facilities. These proposed standards would require, for each air oxidation process vent stream, either use of a combustion device which reduces total organic compound emissions (minus methane and ethane) by 98 weight percent or to 20 ppm by volume, whichever is less stringent, or maintenance of a total resource-effectiveness (TRE) index value greater than 2.2.

The proposed standard implements Section 111 of the Clean Air Act and is based on the Administrator's determination that the synthetic organic chemical manufacturing industry (SOCMI) contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intent is to require new, modified, and reconstructed SOCMI air oxidation facilities to control emissions to the level achievable through use of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

A public hearing will be held, if requested, to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: Comments. Comments must be received on or before January 3, 1984.

Public Hearing. If anyone contacts EPA requesting to speak at a public hearing by November 15, 1983, a public hearing will be held on December 1, 1983 beginning at 10 a.m. Persons interested in attending the hearing should call Mrs. Naomi Durkee at the telephone number listed under **FOR FURTHER INFORMATION CONTACT** to verify that a hearing will occur.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate, if possible) to: Central Docket Section (A-130), Attention: Docket Number A-81-22, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460.

Public Hearing. If anyone requests a public hearing, it will be held at the Environmental Research Center Auditorium, corner of highway 54 and Alexandria Drive, Research Triangle Park, North Carolina.

Persons wishing to present oral testimony should notify Mrs. Naomi Durkee, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 17711, telephone number (919) 541-5578.

Background Information Document. The background information document (BID) for the proposed standard may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "SOCMI Air Oxidation Processes—Background Information for Proposed Standards," EPA-450/3-82-001a.

Docket. Docket Number A-81-22, containing supporting information used in developing the proposed standard, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Robert E. Rosensteel, (919) 541-5596, concerning technical aspects of the industry and control technologies, and Mr. Gilbert H. Wood, (919) 541-5578, concerning regulatory decisions. The address for both parties is Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 27711. As indicated above, please call the U.S. EPA Library for background information documents.

Persons interested in attending the hearing should call Mrs. Naomi Durkee at (919) 541-5578 to verify that a hearing will occur.

SUPPLEMENTARY INFORMATION:

Proposed Standards

Standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> " " " application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated Section 111(a)(1).

For convenience, this will be referred to as "best demonstrated technology" or BDT.

The Administrator has determined that for most air oxidation facilities BDT for VOC reduction is incineration, which can reduce total organic emissions (minus methane and ethane) by 98 percent by weight or to 20 ppm, by volume. Due to variations in factors such as flowrate and organics concentration, the total costs for incineration per unit VOC emission reduction would vary considerably among the different types of air oxidation facilities. The Administrator has also determined, therefore, that for some air oxidation facilities, the cost of incineration per unit of VOC reduced is unreasonably high and BDT is no control. To distinguish between those facilities for which BDT is incineration and those facilities for which BDT is no control, a means of measuring the total cost of control VOC emissions from air oxidation facilities by incineration was developed. This means of measuring the cost of control is called the total resource-effectiveness (TRE) index and is explained more fully in the section entitled "Selection of the Basis of the Proposed Standard."

The proposed standard would require each owner or operator of an affected facility to either reduce process vent stream emissions by 98 weight percent or to 20 parts per million by volume, whichever is less stringent, or to maintain a TRE index value greater than 2.2 The affected facility is designated as any individual product recovery system along with all air oxidation reactors feedings offgas into this system. Each air oxidation reactor not feeding offgas into a product recovery system would constitute a separate affected facility.

An equation is included in the regulation for determining the TRE index value of each vent stream. The process vent stream flowrate, total organic compound (minus methane and ethane) emission rate, net heating value and corrosion properties (whether or not chlorinated compounds are present) would be required to be measured according to the specified Reference Methods in order to calculate the TRE index value. These vent stream characteristics would be measured following the last product recovery device (e.g. condensers, absorbers, carbon adsorbers). The structure of the proposed standard allows an affected facility with a TRE index value of less than 2.2 to add a product recovery device or improve an existing product recovery device to change the vent stream characteristics used for

calculating the TRE index value so that the TRE index value will be above 2.2 and incineration would not be required. An owner or operator might choose to improve product recovery rather than incinerate in some cases due to the lower cost of improved product recovery. Increased product recovery would also have the advantage over incineration of less energy usage and increased retention of product.

Each owner or operator complying with the proposed standard by using an incinerator or stream generating unit (such as a boiler or process heater) with a design heat input capacity of less than 44 MW (150 million Btu/hr) would be required to continuously monitor and record the firebox operating temperature (or, if a catalytic oxidizer were used, the temperature before and after the catalyst bed). If this emission reduction requirement were achieved by use of a steam generating unit with a design capacity of 44 MW or greater, no continuous monitoring would be required. However, records (such as steam production records) would be required which would verify the periods of operation of the steam generating unit. If the VOC reduction requirement were achieved by any other means, the owner or operator would be required to provide information describing the operation of the control device and the process parameter(s) which would indicate proper operation and maintenance of the device so that the enforcing agency could specify appropriate monitoring requirements.

Each owner or operator who seeks to demonstrate compliance with the proposed standard by maintaining a vent stream TRE index value above 2.2 would be required to maintain records of any change in the design or operation of the facility which could affect the TRE index value. Such records would include changes in the production capacity, feedstock type, or catalyst type, as well as the replacement, removal, or addition of product recovery equipment. When any such change takes place, the owner or operator of the facility is required to demonstrate that he is in compliance with the standard: that is, he is to recalculate the TRE index value to document that the facility continues to have a TRE index value above 2.2. Such recalculation can be based on test data reflecting the changes in the system, or best engineering estimates of the effects of the changes. If the recalculated TRE index value for the facility is less than 2.2, the owner or operator shall demonstrate compliance with the 98 percent or 20 ppmv emission limits. Prior notice of any performance testing shall be given to EPA as required by the General Provisions. Performance testing may also be required on a case-by-case basis by the Administrator following any change to the product recovery system in order to verify the TRE index value for the facility.

In addition to maintaining records of certain operating parameters to ensure the proper operation and maintenance of combustion control equipment or product recovery devices, records of instances where the monitored values exceed allowable limitations must be maintained. In addition to maintaining these records, an owner or operator must submit a semi-annual report of the recorded exceedances, of periods when the TRE index value is recalculated and of periods when a steam generating unit is not operating. The requirement of semi-annual reporting may be waived for affected facilities in States that have been delegated authority for enforcement, provided EPA approves the reporting requirements or alternative means of compliance surveillance adopted by the State and the affected facilities comply with the requirements established by the State.

In addition to this proposed standard Reference Methods 1A, 2C, and 2D are being proposed in today's Federal Register.

Summary of Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts associated with the proposed standard were projected by using a national statistical profile of offgas characteristics at existing plants. The offgas parameters included were offgas flowrate, net heating value, total organics (minus methane and ethane) emission rate, and corrosion properties (presence or absence of halogenated compounds). It was assumed that the national distribution of these offgas parameters for new sources would be the same as the distribution for existing sources. Determination of these impacts was based on the use of a single VOC control technique, thermal oxidation. Thermal oxidation is the only VOC control technique universally applicable to SOCMI air oxidation processes. Some processes would employ product recovery equipment to achieve a TRE index value higher than the exemption cutoff, and, in fact, the proposed standards are structured in such a way that encourages this. Such equipment generally has lower associated costs, energy use, and emission reduction. Therefore, the environmental, energy, and economic impacts associated with the proposed standard are somewhat overstated. However, the degree of overstatement of the impacts cannot be quantified.

Under the proposed standard, approximately 19 percent of all new, modified, or reconstructed air oxidation facilities would be under the TRE cutoff. If all of these facilities used incineration to meet the standard, the projected 1986 national VOC emissions from new air oxidation process and product recovery vents would be reduced by an estimated 12,500 megagrams per year (Mg/yr). This national VOC reduction would be approximately 57 percent beyond the 22,000 Mg/yr level that would be expected under typical State implementation plans (SIP's).

Any increase in emissions of other air pollutants as a result of controlling VOC emissions would be negligible. There would be no direct solid waste impacts under the proposed standards, and impacts on noise, space requirements, and availability of resources would be negligible.

No increase in total plant wastewater is projected under the proposed standard. There is no organic wastewater effluent associated with incineration. Therefore, the only facilities which could have an associated water pollution impact are those which might use additional product recovery to achieve a total resource-effectiveness (TRE) value above the proposed 2.2 cutoff. Carbón adsorption is the only product recovery technique currently in use in the industry which has an associated organic wastewater effluent. Based on past industry experience, only three air oxidation chemical manufacturing processes are expected to employ carbon adsorption. Of these three processes only the maleic anhydride from benzene feedstock process might have a TRE value below the proposed 2.2 cutoff. However, if any new maleic anhydride facilities are built, it is projected they will utilize butane feedstock rather than benzene. The maleic anhydride from butane feedstock process would not use carbon adsorption for product recovery and therefore would have no additional wastewater.

If an existing benzene-feedstock maleic anhydride facility were modified or reconstructed (which is unlikely), such a facility might have a TRE value below the proposed cutoff, in such an event, an if additional carbon adsorption were employed in lieu of incineration or some other type of product recovery, the adsorption unit of a typical maleic anhydride facility would generate approximately 500 Mg/yr of VOC which would be sent to

wastewater treatment. The organic load of the wastewater from carbon adsorption would be less than 10 percent of the total liquid waste from such a facility. This wastewater stream could be treated along with the other plant effluent or recycled to the process. No new wastewater treatment plant or additional sewer capacity would be necessary.

The fifth year energy requirements due to VOC control under the proposed standard would be 0.77 billion megajoules per year (MJ/yr), (360 bbl oil/day). The projected national and individual plant energy impacts are considered reasonable.

The fifth year cost impacts of the proposed standards also would be reasonable. The 1986 national annualized cost for VOC control would be $10 million. The fifth year national capital cost for VOC control would be $18 million.

An economic analysis indicated that the costs of VOC control due to the proposed standard could be passed on with little or no effect on the profitability of the air oxidation chemical producing industry. Projections made by employing process-specific assumptions indicate that all air oxidation chemicals would have product cost increases due to the proposed standard of less than 5 percent of the projected product price. The price changes for the 36 chemicals that are currently produced using the air oxidation process, assuming control costs would be passed through totally, would range from 0 to a 3.1 percent increase, except for maleic anhydride produced by the benzene process, which showed an estimated 4.2 percent increase. New maleic anhydride plants are expected to employ the butane process (which showed an estimated 3.1 percent increase), instead of the benzene process, even in the absence of the proposed standard. Finally, there would be no adverse effects on employment because the proposed standard would not affect demand for the air oxidation chemicals.

It is projected that, in the absence of the proposed standards, uncontrolled VOC emissions would be reduced an average of 72 percent by State regulations. Seventy-two percent represents a weighted average of the regulations in States where new sources are projected to be built. The actual control required would vary considerably from State to State. Therefore, the impacts for individual plants would vary depending on the State where the affected facility is located. A typical air oxidation facility located in a State with a relatively stringent standard would reduce VOC emissions 1200 Mg/year beyond what the SIP would require at an incremental annualized cost of $1.4 million under the recommended standard. A typical air oxidation facility in a State with no State requirement would reduce VOC emissions by about 7400 Mg/yr at an estimated annualized cost of $2.1 million under the recommended standard.

Standards of performance have other benefits in addition to achieving reductions in emissions beyond those required by a typical State implementation plan (SIP). They provide documentation which reduces uncertainty in case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas. This documentation includes identification and comprehensive analysis of alternative emission control technologies (if any), development of associated costs, an evaluation and verification of applicable emission test methods, identification of specific emission limits achievable with alternate technologies and an economic analysis that reveals the affordability of controls.

The rulemaking process that implements a performance standard assures adequate technical review and promotes participation of representatives of the industry being considered for regulation, government, and the public affected by that industry's emissions. The resultant regulation represents a balance in which government resources are applied in a well publicized national forum to reach a decision on a pollution emission level that allows for a dynamic economy and a healthful environment.

Moreover, this industry is rapidly evolving and growing, and the emissions include a wide range of organic compounds, some of which are currently being studied as potentially being toxic. The continuing evolution of this industry, as well as the difficulties and time required to determine with certainty adverse health effects associated with these chemical emissions, will continue to make chemical-by-chemical control of toxic emissions a costly and uncertain process. Accordingly, an effective NSPS offers benefits beyond that associated with the reduction of VOC's as oxidant precursors.

Rationale Selection of Source and Pollutant

The EPA priorty list, 40 CFR 60.16 (44 FR 49222, August 21, 1979), ranks major source categories for which NSPS are to be promulgated. This list implements the Clean Air Act and reflects the Administrator's determination that emissions from the listed source categories contribute significantly to air pollution. The synthetic organic chemical manufacturing industry (SOCMI) was ranked highest priority for NSPS development on the final priority list of 59 major source categories. Organic chemical plants are a major source of VOC emissions which contribute to ozone formation.

VOC is emitted from four major subcategories within SOCMI: process vents, fugitive, storage, and secondary emission sources. Standards have already been proposed for SOCMI fugitive sources, and are being developed for storage sources.

Process vent emissions of VOC are estimated to be 50 to 55 percent of the total VOC emissions from SOCMI, according to the EPA "1978 Survey and Ranking of VOC Emission Sources in SOCMI" (EPA-450/3-80-023). Process vent emissions are emissions from any of the process or associated product recovery vents in a SOCMI chemical manufacturing process. Process vent emission sources include pressure relief valves, evacuation of equipment for vacuum processing, and venting of VOC-containing inert gases. Among those sources which vent VOC-containing inert or reaction gases are air oxidation processes. An air oxidation unit process is one that uses air, or a combination of air and oxygen, as an oxygen source in combination with one or more organic reactants to produce one or more SOCMI chemicals.

Air oxidation process vent emissions are estimated to be about 110,000 Mg/yr. Air oxidation chemical-producing plants are located in 30 States and Puerto Rico, with some existing near urban population centers. An overall growth rate projection for air oxidation chemicals using a weighted-by-capacity average is 4.7 percent. Approximately 49 new air oxidation facilities are projected to be built between 1981 and 1986.

Thermal oxidation is a VOC control technology applicable to all SOCMI air oxidation processes. Therefore, because the Agency can establish standards of performance based on a control technology which is available to reduce these emissions, the Administrator is proposing such standards.

The standards cover only processes which emit any VOC's include all organic compounds except those which the Administrator has determined do not participate in atmospheric photochemical reactions. The

Administrator has determined that the following organic compounds are not photochemically reactive: methane; ethane; 1,1,1-trichloroethane; methylene chloride; trichlorofluoromethane, dichlorodifluoromethane; trifluoromethane; trichlorotrifluoroethane; dichlorotetrafluoroethane; chloropentafluoroethane. Even though the standards cover only those processes which emit VOC, the emission limits for processes which emit VOC are expressed in terms of total organic compounds (minus methane and ethane) rather than VOC. This is a reflection of the technology, data, and test method upon which the standards are based. This is discussed in greater detail in a later section of this preamble entitled *Compounds Used in Determining Compliance.*

Oxychlorination and ammoxidation processes have reaction, emission, and control system design characteristics sufficiently similar to the other air oxidation processes that all of these may be grouped together. For this reason, all oxidation unit processes, including ammoxidation and oxychlorination processes, that use air (or a combination of air and oxygen) have been chosen as the source for control by the proposed standard.

In addition to VOC emissions, other pollutants emitted from SOCMI air oxidation sources included carbon monoxide (CO), nitrogen oxides (NO_x) and sulfur oxides (SO_x). These other pollutants are emitted in much lower quantities than the estimated VOC emissions. VOC is the only pollutant covered by the proposed standard. Due to the size of this source category, covering other smaller pollutants at this time would have been an unmanageable task. The Agency will examine these other pollutants independently.

Selection of Regulatory Approach and Affected Facilities

Two general regulatory approaches could be used in developing standards for SOCMI. The first approach involves the chemical-by-chemical development of standards, which has historically been the most commonly used approach in developing standards of performance for new stationary sources. This approach would involve establishing standards for each specific chemical manufacturing process.

The second approach involves the development of standards on the basis of similar types of emission sources and applicable emission control techniques. The second approach is more resource-efficient than the first approach because a large number of specific chemical processes can be covered by one regulation. In addition, because of the similarity of processes regulated by a particular standard and the similarity of applicable controls, the energy and cost impacts can be adequately addressed as required by the Clean Air Act.

Air oxidation facilities currently use 36 specific reaction and equipment configurations to manufacture 36 different organic chemicals. Because of the many types of facilities and processes in the air oxidation industry, a chemical-by-chemical development of standards would require large amounts of time. Therefore, compared to the unit process approach, a chemical-by-chemical approach would result in a long delay in achieving a significant emission reduction from air oxidation processes.

Despite the large variation in reaction types used to produce air oxidation chemicals, air oxidation processes can be grouped together because they have several similar characteristics, including the need to vent to the atmosphere large quantities of VOC-containing nitrogen from the process air, the VOC content of which is too low to be further recovered with a cost savings. Therefore, air oxidation process vent streams typically have high flowrates and low VOC contents. Although further VOC recovery does not result in cost savings due to the low VOC content, technology does exist for control of these VOC emissions from all air oxidation processes. This technology is thermal oxidation. The design characteristics and, therefore, costs for thermal oxidizer control systems would be similar among air oxidation facilities and different from a typical design for control of other SOCMI process emissions such as oxygen oxidation unit processes or distillation unit operations. These similar design characteristics would be large equipment sizes, due to the relatively high air oxidation vent stream flowrates, and high supplemental fuel requirements, due to the relatively low vent stream VOC contents and heating values. Therefore, because control techniques are available for the entire industry group and because regulating the entire group would be more resource-efficient, a single regulation is being proposed for controlling process VOC emissions from all SOCMI air oxidation facilities.

The choice of the affected facility for these standards is based on the Agency's interpretation of Section 111 of the Clean Air Act and on the judicial construction of its meaning [ASARCO, Inc v. EPA, 578 F.2d 319 (D.C. Cir. 1978)]. Under Section 111, the standards of performance for new stationary sources must apply to "new sources;" "source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" [Section 111(a)(3)]. Most industrial plants, however, consist of numerous pieces or groups of equipment which emit air pollutants, and which may be viewed as "sources." EPA therefore uses the term "affected facility" to designate the equipment, within a particular kind of plant, which is chosen as the "source" covered by a given standard.

In designating the affected facility, EPA must decide which piece or group of equipment is the appropriate unit (the source) for separate emission standards in the particular industrial context involved. The Agency must do this by examining the situation in light of the terms and purpose of Section 111. One major consideration in this examination is that the use of a narrower designation results in bringing replacement equipment under standards of performance sooner. If, for example, an entire plant is designated as the affected facility, no part of the plant would be covered by the standard unless the replacement causes the plant as a whole to be "modified" or "reconstructed." The plant as a whole could be considered modified only if the replacement results in an increase in the aggregate emissions from the entire plant. The Agency would consider the plant as a whole to have been reconstructed only if the cost of the replacement exceeds 50 percent of the cost of an entire plant. If, on the other hand, each piece of equipment is designated as the affected facility, then as each piece is replaced, the replacement piece will be a new source subject to the standard. Since the purpose of Section 111 is to minimize emissions by application of the best demonstrated control technology at all new and modified sources (considering cost, other health and environmental effects, and energy requirements), there is a presumption that a narrower designation of the affected facility is proper. This ensures that new emission sources within plants will be brought under the coverage of the standards as they are installed. This presumption can be overcome, however, if the Agency concludes either that: (a) A broader designation of the affected facility would result in greater emissions reduction than would a narrow designation; or (b) the other relevant statutory factors (technical feasibility, cost, energy, and other environmental impacts) point to a broader designation.

Several air oxidation reactors may feed offgases into a common product recovery train. The characteristics of the

emissions vented into the atmosphere from the product recovery train are determined by the offgases from each of the reactors, as well as by the product recovery process from each of the reactors, as well as by the product recovery process itself. The contribution of each reactor to these emissions cannot be determined precisely. Consequently, designating each of several reactors connected to a common product recovery train as a separate affected facility was judged to be technically infeasible. Since all the reactors and their common product recovery train operating in conjunction determine the emissions from the air oxidation process, the narrowest feasible affected facility is that defined as the combination of those reactors and their common product recovery train.

It is feasible, although uncommon, for emissions from a reactor to be vented directly to the atmosphere. Since the characteristics of emissions from reactors not feeding offgases into a common product recovery train can be determined for each reactor separately, each such reactor has been designated as a separate affected facility.

Therefore, the Administrator designated the individual reactor-product recovery train consisting of an individual product recovery system (series of product recovery units) along with all air oxidation reactors feeding offgas into this system as the affected facility. Each air oxidation reactor not feeding offgas to a product recovery system would be designated as a separate affected facility. The affected facility would end at the vent at which the air oxidation reactor offgas is emitted to the atmosphere.

If two or more series of product recovery equipment units were arranged in parallel such that they shared an ultimate vent to the atmosphere, each train of recovery equipment, with its associated air oxidation reactors, would be considered a separate affected facility, as long as each reactor was piped to only one of the series of recovery equipment. Also, if a new reactor were added to an existing facility such that a modification resulted, the affected facility would include the new reactor, all recovery equipment into which the new reactor was piped, and any other reactors also piped to the same recovery equipment. Any nonair oxidation reactors feeding offgas into an affected facility's equipment train would not be considered part of that affected facility. If any or all of the air oxidation reactor offgas at any point were conducted through the equipment of any other process in the plant (other than the air oxidation product recovery train), the intervening nonair oxidation equipment would not be included as part of the affected facility. Such a diversion of air oxidation offgas might be done to provide an inert blanket for another type of reactor. Such a diversion might result in the air oxidation reactor offgas being emitted from more than one atmospheric vent. In this case, each vent, along with any product recovery equipment through which the vented air oxidation offgas would have passed, and any associated air oxidation reactors, would constitute an affected facility.

Selection of Regulatory Alternatives

Control Techniques. A variety of control devices, including condensers, absorbers, adsorbers, and incinerators, can be used to reduce VOC emissions from air oxidation unit processes. However, selecting the most applicable VOC control device for a particular chemical manufacturing process and determining the degree of control achievable would depend on the chemical composition of the waste stream and other process characteristics. The specificity and effectiveness of devices such as condensers, absorbers, adsorbers, and catalytic incinerators may be greatly affected by the vent stream flowrate and VOC concentration, the chemical and physical properties of the VOC and other contaminants, and the vent stream water content and temperature. As a result, none of these potential control devices would be universally applicable for reduction of VOC emissions from all air oxidation processes.

Air oxidation processes use a combination of absorption devices, condensers, or carbon adsorption units for product recovery (or for recovery of unreacted raw material). These devices are usually designed to recover only as much of the VOC as results in a cost savings and, therefore, would not be considered control devices. However, in some plants these devices are designed to remove more than that amount which results in cost savings. In this case, the devices operate both for product recovery and as control devices for emission reduction or to reduce the pollutant load on some other final control device.

Thermal oxidation is a control technique in which a mixture of gases, including a vent stream, excess combustion air, and/or fuel, is held at a sufficiently high temperature for a sufficiently long period of time to insure complete combustion of the VOC to carbon dioxide and water. If the VOC stream has a sufficiently high heating value, part of it is passed through the burner in place of part or all of the fuel. The thermal oxidizer operating temperature, chamber residence time, combustion gas mixing, and several other factors related to individual waste stream characteristics determine the exact efficiency of this reaction. Operation of a thermal oxidizer is much less dependent on process and vent stream characteristics than are other VOC control and/or product recovery devices and, consequently, is the only demonstrated VOC control technology universally applicable to SOCMI air oxidation processes. Also, data show that thermal oxidation can achieve the highest feasible VOC control level of all currently demonstrated technologies. All new incinerators can achieve at least a 98 percent VOC reduction or 20 ppmv exit concentration. This control level can be achieved for all air oxidation reaction processes by incinerator operation at conditions which include a maximum of 870°C (1600°F) and 0.75 second residence time.

Tests were performed on the destruction efficiency of incinerators operating at various temperatues [700°C (1300°F) to 800°C (1500°F)] and residence times (0.5 to 1.5 seconds). These tests showed a destruction efficiency of 98 percent to be achievable. In addition, kinetics calculations were performed which compared the tested conditions with the destruction efficiency of an incinerator operated with a residence time of 0.75 second at 870°C. This temperature is known to be achievable in existing incinerators. These calculations show that these conditions are more conductive to complete destruction than the tested conditions.

Therefore, 870°C and 0.75 second were determined to represent the achievable operating conditions which might be necessary to achieve 98 percent total organics (minus methane and ethane) destuction under the worst case conditions.

Kinetics calculations describing complex combustion reaction mechnisms point to much slower reaction rates at very low total organics concentrations. Because of these slower combustion reaction rates, maximum achievable organic compounds destruction efficiency decreases as inlet concentration decreases. Available data show that the lowest concentration achievable by combustion of inlet streams below approximately 2000 ppmv is 20 ppmv. (For air oxidation vent stream with a concentration of 2000 ppm, the incinerator combustion air introduces a dilution factor of about 2, so that the actual incinerator inlet

concentration is about 1000 ppm.) The Agency has therefore selected 20 ppmv as the limit that allows fully for the drop in achievable destruction efficiency with decreasing inlet concentration.

The data also show that the effect of compound identity on destruction efficiency increases at incineration temperatures lower than 760°C (1400°F), although precise quantitative relations could not be determined. However, at temperatues above 760°C, the identity of nonhalogenated compounds has little effect on the destruction efficiency of thermal oxidizers. Because organic compounds which contain halogens undergo complete combustion more slowly, at any given temperature, more stringent conditions are required to achieve 98 percent destruction when incinerating halogenated vent streams. The impacts of emission control were projected assuming a combustion temperature of 1100°C (2000°F) and 1.0 second residence time for halogenated vent streams. Because the incinerator outlet stream for such facilities would contain corrosive hydrogen halide, a flue gas quencher and scrubber were included in the incineration system design and considered in the projection of cost impacts.

At temperatures over 760°C (1400°F), the oxidation reaction rate is much faster than the rate at which mixing takes place. Therefore, organic compound destruction becomes more dependent upon the fluid mechnics within the oxidation chamber. Chamber design and burner and baffle configurations provide for turbulent flow for improved mixing. One practical manner of achieving good mixing and efficiency is to adjust the newly installed equipment (e.g. by changing baffle configurations) to improve performance.

Although the emission test data cited above would also support the achievability of 95 percent reduction at a thermal oxidizer operating temperature of 760°C (1400°F), this reduction efficiency was not considered as an alternative control technique. This 95 percent alternative was not considered because the additional emission reduction associated with 98 percent control at 870°C relative to 95 percent control at 760°C was judged to be large when compared to the small incremental cost and energy impacts associated with the two control levels.

In summary, thermal oxidation is the only VOC control device that is universally applicable to SOCMI air oxidation processes. Thermal oxidation can achieve a greater degree of VOC control than any other device, and requires only a limited amount of vent stream data (flowrate, heating value, and whether chlorinated compounds are present) to determine control costs.

Selection of Format for Proposed Standard and Emission Limits. Several formats could be used to implement the proposed standard. Section 111 of the Clean Air Act requires that standards of performance be prescribed unless, in the judgment of the Administrator, it is not feasible to prescribe or enforce such standards. Because emission from air oxidation process or product recovery vents, as well as emissions from any type of combustion control equipment, can be measured, it was determined that an emission limitation (performance) standard would be appropriate. A mass emission standard, a percent reduction standard, and a concentration standard were considered.

Because of the variety in offgas flowrates and VOC contents for the many chemical reaction processes and facilities in the air oxidation source category, mass emission rates from sources using 98 percent efficient incinerators would vary considerably. Consequently, a mass emission limit based on an average source would require more than 98 percent control demonstrated technology (BDT) at some facilities and less at others. Therefore, a mass emission standard was considered inappropriate, because it would not require best demonstrated technology (BDT) at each source.

Air oxidation process vent streams have as much variation in volume percent VOC concentration as in mass emission rates. Any standard based solely on a concentration limit would require more than BDT at some facilities and less than BDT at others. Therefore, a standard based solely upon concentration was considered inappropriate. However, a concentration limit might be used in combination with another type of emission limit, if the applicablilty of the concentration limit were restricted to facilities with a limited range of offgas organics content.

A weight percent reduction standard would be feasible because the control device inlet and outlet emission rates can be measured. Furthermore, a given set of incinerator operating conditions tends to result in a given weight percent organics reduction, rather than in an absolute outlet organics concentration or emission rate. As discussed above in the section entitled *Control Techniques*, all new incinerators can achieve at least a 98 weight percent reduction in total organics (minus methane and ethane), provided that the total organic (minus methane and ethane) concentration of the process vent stream is greater than approximately 2000 ppm (volume, by compound). Therefore, a weight percentage reduction standard, based on the mass rate of organics exiting the control device versus the mass rate of organics entering the device, would be appropriate for vent streams with total organics (minus methane and ethane) concentrations above approximately 2000 ppm. For vent streams with organics concentrations below approximately 2000 ppm, it has been determined that an incinerator outlet concentration of 20 ppm (volume, by compound), or lower, is achievable by all new thermal oxidizers. Therefore, EPA concluded that the format of the proposed standard for air oxidation process vent emissions should include a combination of weight percent reduction and a volume concentration standard. The proposed emission limits would be a 98 percent total organics (minus methane and ethane) reduction, or total organics (minus methane and ethane) reduction to 20 ppm (volume, by compound), whichever would be less stringent for a given facility. The concentration limit of 20 ppmv would be based on a vent stream oxygen concentration, at the control device outlet, of 3 percent by volume.

Regulatory Analysis. As explained above, thermal oxidation is clearly the most effective control technology and is demonstrated for application at all facilities. For this reason, the Agency concluded that any regulatory alternative under the Administrator's consideration would necessarily incorporate the use of thermal oxidation. (This contrasts with the development of most other NSPS's where the Agency has examined regulatory alternatives distinguished from each other by control device.) Accordingly, each alternative would require a control efficiency of 98 weight percent or reduction to 20 ppmv exit concentration, whichever is less stringent, for those affected facilities required to control emissions.

However, because this standard would cover a variety of types of SOCMI plants, the offgas parameters which would affect the cost and energy impacts of VOC control by thermal oxidation would vary. These parameters include volume flowrate (which affects equipment size) and heating value (which affects the amount of supplemental fuel required to achieve complete combustion). Other varying offgas parameters include organics content and corrosion properties (such as the presence of chlorinated compounds, which affect control equipment structural properties). Because of this variety, control costs per weight unit emission reduction would

also vary considerably from plant to plant. Therefore, the Agency needed to decide whether thermal oxidation is the "best demonstrated technology" for all, or only a portion, of the projected affected facilities. This depends on the impacts associated with thermal oxidation control at facilities with different vent stream characteristics. Thus, as discussed in the section entitled *Identification of Regulatory Alternatives*, under each additional alternative an additional percentage of sources would be required to meet the proposed standards. (For example, under the first alternative, 7 percent of the projected affected facilities would be required to meet the standards. Under the second alternative, those 7 percent plus an additional 7 percent of projected facilities would be required to meet the standards, and so on.)

The Agency structured the regulatory alternatives so that those facilities with the lowest projected annualized cost of control, per unit of VOC destroyed, would be controlled first (i.e., under the first and all other alternatives) and those with higher costs would be controlled last (i.e., under only the latter alternatives). This method of choosing which facilities would be required to control emissions ensures that for any given regulatory alternative, the greatest national VOC emission reduction is obtained for the amount of money spent.

The following discussion and the section entitled *National Emissions Profile* describe how the Agency calculated theoretical control costs for each vent stream in order to rank vent streams by cost per unit of VOC destroyed. All new incinerators, if properly installed, adjusted, maintained, and operated, can achieve 98 percent emission control of nonhalogenated streams when operated at conditions no more stringent than a combustion chamber temperature of 870°C and residence time of 0.75 second. The impacts of each regulatory alternative were therefore projected based on the use, by each facility with nonhalogenated vent stream required to reduce emissions, of a thermal oxidizer operated at 870°C and a 0.75 second residence time. For halogenated vent streams, operating conditions of 1100°C and 1.0 second residence time were assumed. It was assumed that adjustments of the thermal oxidizer unit after start-up, in order to optimize combustion gas mixing, would be necessary. The costs of such optimization were considered in projecting the costs of control.

In order to avoid an overly conservative estimate of the cost impact of thermal incineration, it was assumed that heat recovery would be employed in all intances in which it was technically feasible, met safety requirements, and would tend to lower the projected annualized cost of control. Such employment of heat recovery equipment is standard industry practice. Use of heat recovery equipment results in lower projected energy use and energy costs, but higher projected, capital costs.

The contributing factors to annualized costs include capital charges, supplemental fuel, electricity, operating labor, and maintenance labor. For offgas containing chlorinated compounds, scrubbing water, quench water, and caustic soda, as well as additional capital charges for a flue-gas scrubber, also contribute to annualized cost. Facilities with higher VOC emission rates would tend to have a lower cost, per unit of VOC destroyed, since the achievable emission reduction would be higher than for other vent streams. Under each regulatory alternative, therefore, such facilities would tend to be controlled before other streams. Vent streams with higher net heating values would tend to have lower supplemental energy requirements than other streams, and would, therefore, tend to be controlled before other streams under each regulatory alternative. Facilities with lower offgas flowrates would have relatively higher capital costs, per unit of VOC destroyed, than would streams with similar VOC concentrations and heating values, but higher flowrates. This is true because achievable emission reduction is proportional to flowrate for vent streams with similar VOC concentrations and heating values, whereas capital costs increase less rapidly as flowrate increases, due to economies of scale. Under each regulatory alternative, therefore, facilities with higher offgas flowrates would tend to be controlled before streams with similar emission rates and heating values, but lower flowrates.

National Emissions Profile. One model plant would not have been sufficient for an accurate projection of the impacts associated with each regulatory alternative. Because of the number and diversity of facilities and manufacturing processes in the air oxidation industry, a large number of model plants would have been required. If the use of many model plants had been necessary, the prospective regulatory alternative analysis would have been predicted to take so much time that the unit process approch to regulation would have had little or no advantage over a chemical-by-chemical approach. However, only a limited amount of vent stream data is required to determine incinerator costs and efficiency. The required data include offgas flowrate, net heating value, and total organics (minus methane and ethane) mass emission rate. It must also be known whether the offgas contains halogenated compounds. Therefore, although data from many types of processes are still required in order to adequately represent the air oxidation industry, the data need not consist of fully designed model plants. Rather, a national statistical profile of air oxidation processes was constructed. The national profile characterizes air oxidation processes according to national distributions of the three critical offgas parameters for halogenated and nonhalogenated vent streams. The impacts of each regulatory alternative are therefore evaluated as impacts upon the entire population of affected facilities, as represented by the national profile. The emission and production factors used to construct the data base for the statistical procedure and national profile are from existing air oxidation plants that represent about 36 percent of the total air oxidation plant population. Because there is no recognizable bias involving the four offgas parameters in this data sampling, this percentage of plants provides an adequate sample size to allow construction of a profile that is representative of the entire air oxidation segment of SOCMI. In addition, it is assumed that the overall distribution of key vent stream variables for the new air oxidation plants would be the same as that for the existing population.

The actual use of the national statistical profile assumes that the distribution of offgas flow, VOC emission rate, and stream heating value is chemical independent. Chemical identifies are not considered in the profile, nor is there claimed to be a one-to-one correspondence between any one data point of three offgas parameters and an existing or new offgas stream. It is assumed, however, that the overall proportions and distributions of the parameter values and data points are similar to those of the new population of air oxidation facilities. Thus, since the national statistical profile contains 59 data points, each data point represents 1/59 of the new population. Each data point represents a hypothetical vent stream. Therefore, the impacts of a given regulatory alternative, such as annualized cost of control, VOC emission reduction, and facility cost-effectiveness, can be associated with each data point. It is not assumed that

such individual impacts on a data point would represent impacts on any given new facility, nor are the data points used as individual impact models. Instead, each data point represents 1/59 of the overall projected new population of facilities. Therefore, the impacts of each regulatory alternative represent impacts on the projected new source population. Due to the wide variation in processes used and in the types of control devices present across the air oxidation industry, only uncontrolled emission factors and vent stream characteristics are included in the data set. Since uncontrolled emissions are subject to great uncertainty because of the difficulty in defining what is a pollution control device, all process stream data represent hypothetical uncontrolled emissions, which are considered, in this analysis, to be the process stream exiting the primary (first) product recovery device.

The hypothetical uncontrolled VOC emissions from affected facilities in the fifth year after proposal of the standards were projected to be 78,000 Mg/yr. Actual uncontrolled emissions, in the absence of SIP's, would probably be lower, because some additional degree of product or integrated energy recovery would often result in a cost savings for a facility. An average baseline emission control level was estimated as described below in the section entitled *Baseline Emission Control.*

Baseline Emission Control. The regulatory baseline was estimated as a weighted average of current SIP's except for the assumption that modified SIP's would be in force in ozone NAAQS nonattainment areas requesting extension beyond 1982. EPA assumes that modified SIP's would reflect the reasonably available control technology recommended in the SOCMI air oxidation draft control techniques guideline document. For the purpose of structuring the regulatory alternatives, the Agency estimated the baseline to be 72 percent reduction from hypothetical uncontrolled VOC emissions. However, the actual control required would vary considerably from State to State. If SIP's in ozone NAAQS nonattainment areas requesting extension beyond 1982 are not modified to reflect the reasonably available control technology recommended in the SOCMI air oxidation draft control techniques guideline document, the estimated regulatory baseline would be 66 percent reduction from uncontrolled VOC emission.

Identification of Regulatory Alternatives. Under each successive regulatory alternative, an additional percentage of projected affected facilities would be subject to the 98 percent or 20 ppmv standard. Each successive increment of sources required to meet the standards would have higher per-unit control cost than the increment of sources added under the previous alternative. To develop the regulatory alternatives, the Agency ranked the data points in the national profile in order of increasing cost-effectiveness of VOC emission control by thermal oxidation. Sixty regulatory alternatives could be analyzed, one for no VOC emission control at all, plus 59 additional alternatives based upon inclusion of each successive data point. The Agency chose, however, to group the 59 data points into 6 alternatives for the purpose of analysis.

Alternative O represents the baseline level of control. Under Alternatives I through VI, the percentages of all projected facilities required to reduce emissions 98 percent to 20 ppmv would be 7, 14, 19, 27, 47, and 100, respectively. This would result in corresponding national VOC emission reductions of approximately 31, 46, 57, 66, 81, and 98 percent from the baseline level. As stated before, these alternatives are based on the use of a thermal oxidizer operated at 870°C (1600°F) with a chamber residence time of 0.75 second to achieve 98 percent emission control.

Environmental Impacts. Assuming a 72 percent baseline of control, VOC emissions in the fifth year after proposal of the standards were projected to be 22,000 Mg/yr. Table 1 shows the incremental national VOC emissions and percent emissions reductions from the baseline level for each regulatory alternative. Alternative I (31 percent national VOC reduction from baseline) would reduce national VOC emissions to 15,000 Mg/yr. The most stringent regulatory alternative, Alternative VI, would reduce national VOC emissions by 98 percent from the baseline level to 440 Mg/yr.

The generation of NO_x by the combustion process could have a negative impact on ambient air quality by contributing to ozone formation. The principal factors affecting the rate of NO_x formation are the amount of excess air available, the peak flame temperature, the length of time that the combustion gases are at peak temperature, and the rate of cooling of the combustion products. Because of the relatively low combustion temperatures and relatively short residence times associated with control of VOC using thermal incinerators, the rate of NO_x formation is expected to be low.

TABLE 1. SUMMARY OF ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS OF EACH REGULATORY ALTERNATIVE

Regulatory Alternative	Cutoff TRE Index	Range of Facility Cost Effectiveness Values ($/Mg)[a]	Percent of Sources Affected	National Emissions (1000 Mg/yr)	Percent Emissions Reduction from Baseline	National Annualized Cost (Million $/yr)	Average Cost Effectiveness ($/Mg)[b]	Average Cost Effectiveness ($/Mg)[c]	Average Cost Effectiveness (for Facilities Not Covered by Previous Alternative ($/Mg)[c]	National Capital Cost (Million $)
Baseline	-	-	0	21.8	0	0	-	-	-	0
I	.74	270 -660	7	15.2	31	3.0	130	450	450	6.1
II	1.5	1,100 -1,300	14	11.9	46	7.0	190	680	1,200	13
III	2.2	1,400 -1,900	19	9.4	57	10.3	230	830	1,400	18
IV	3.1	1,900 -2,700	27	7.5	66	14.7	280	1,000	2,200	26
V	6.2	2,700 -5,500	47	4.3	81	27.6	440	1,600	4,000	42
VI	6,000	5,700 -5,400,000	100	0.44	98	66.5	860	3,100	10,000	87

[a] Lowest and highest project cost-effectiveness values for facilities reducing emissions by 98 percent under the given regulatory alternative, but not reducing under the previous alternative. These cost-effectiveness values calculated with respect to baseline emissions.

[b] Calculated with respect to uncontrolled emissions.

[c] Calculated with respect to baseline emisisons.

Uncontrolled Emisssions = 78,000 Mg/yr

Baseline Emissions = 22,000 Mg/yr

Thermal oxidizer outlet concentrations of NO_x were measured in seven sets of thermal oxidizer tests conducted at three air oxidation plants. The test results indicate that NO_x outlet concentrations range from 8 to 200 ppmv (0.015 to 0.37 g/scm).

Although there are conflicting data, some studies report that incineration of vent streams containing high levels of nitrogen-containing compounds also may cause increases in NO_x emissions. The maximum outlet NO_x concentration of 200 ppmv was measured at an acrylonitrile plant. The vent stream of this plant does not contain nitrogenous compounds. The NO_x outlet concentrations measured at the other two plants, whose vent streams do not contain nitrogenous compounds, range from 8 to 30 ppm (0.015 to 0.056 g/scm).

Acrylonitrile manufacture is the only air oxidation process expected to have NO_x emissions much higher that the detectable limit if controlled by thermal oxidation. However, according to the national profile, the achievable VOC emission reduction for acrylonitrile facilities would be about one to two orders of magnitude greater than the increase in NO_x emissions due to control. For this reason, the Administrator determined that the acrylonitrile process should not be exempt from the proposed standard. Control of the acrylonitrile process has one of the lowest costs per unit VOC reduction of any air oxidation process. Therefore, acrylonitrile facilities would be controlled under each of the six regulatory alternatives more stringent than the baseline alternative. There is, therefore, no significant incremental increase in NO_x emissions associated with the various regulatory alternatives.

In addition to generation of NO_x, the control of VOC emissions from halogenated vent streams by thermal oxidation may result in the release of chlorinated combustion products to the environment. However, flue gas quenching and scrubbing could be used to remove these compounds from the incinerator outlet stream. Current industry practice among air oxidation facilities with chlorinated vent streams which employ combustion devices is to employ flue gas scrubbing. The capital and operation costs associated with flue gas quenching and scrubbing were taken into account in projecting the cost impacts.

Control of VOC emissions using thermal oxidation would not result in any significant increase in waste water discharge by air oxidation unit processes. No water effluents are generated by thermal oxidizers themselves.

Use of an incinerator/scrubber system for control of VOC emissions from oxychlorination vent streams would result in increased water consumption. The increase in total plant waste water would be relatively small and would not affect plant waste treatment or sewer capacity. However, if the scrubbed hydrochloric acid is not recovered, it may be necessary to adjust the pH of the scrubber effluent by treatment with

caustic (NaOH) before it is released into the plant waste water system. The salt (NaCl) formed by the caustic treatment must be purged from the system and properly disposed of. Acceptable methods of disposal include direct waste water discharge or deep well disposal. The increased water consumption and caustic (NaOH) costs were included in the projected operating costs for those data vectors in the national profile representing halogenated vent streams. Costs associated with disposal of NaCl were not believed to be significant and, therefore, were not included in the projected impacts.

There are not expected to be any differences among the regulatory alternatives in cost and energy impacts due to the special additional control equipment and resource use associated with control of chlorinated vent streams. Only one air oxidation process, ethylene dichloride manufacture, has offgas containing chlorinated compounds. This process has a new negative total resource use (net total resource credit) per unit VOC destroyed, associated with the use of incineration. Therefore, the ethylene dichloride process would be controlled under even the least stringent regulatory alternative.

Energy Impacts. The projection of energy impacts for each regulatory alternative was based on the use of thermal oxidation to control VOC emissions from air oxidation process vents. Maintenance of the required thermal oxidizer operating conditions requires supplemental fuel, commonly in the form of natural gas. The amount of supplemental fuel needed depends on vent stream temperature and net heating value, flowrate, incineration temperature, and type of heat recovery used. Due to the use of heat recovery techniques, combustion of some air oxidation waste streams would result in a net production of energy even though supplemental fuel would be necessary for flame stability. Up to 70 percent waste heat recovery could be expected using techniques currently in wide use in the air oxidation industry. In addition to supplemental fuel, electricity requirements for equipment such as pumps, blowers, and instrumentation contribute to the total energy use for VOC control. Total electrical needs are relatively small compared to energy requirements in the form of supplemental fuel for thermal oxidation. The fifth year national energy use would increase from 0.23 billion MJ/yr (110 bbl oil/day) for Alternative I (3% percent national VOC reduction from baseline) to 6.0 billion MJ/yr (2,800 bbl oil/day) for Alternative VI (98 percent national VOC reduction from baseline).

Economic Feasibility and Costs. Both capital and annualized operating costs were used to determine total national costs for each regulatory alternative. These national impacts are summarized in Table 1. The fifth year total national annualized cost would increase from $3 million per year for Alternative I to $87 million per year for Alternative VI. The fifth year total national installed capital cost would increase from $6.1 million for Alternative I to $87 million for Alternative VI.

An economic analysis was performed to determine if control of VOC emissions from individual air oxidation processes would be economically feasible. Control by thermal oxidation was considered to be economically feasible if the following criteria were met: (1) The projected product cost increase due to control remains below 5 percent of the projected product price, (2) the net present value of new plants does not become negative (indicating that they have become an unprofitable investment), (3) the capital costs for control do not exceed 20 percent of the uncontrolled plant fixed investment costs, and (4) new plants do not experience substantial adverse impacts due to foreign competition.

The first step in the economic analysis was performed using a worst-case set of assumptions. One worst-case assumption was that the vent stream contained no oxygen, which led to maximum projected equipment sizes and larger supplemental fuel requirements. A second worst-case assumption was that no waste-heat boiler would be used for any stream not containing halogenated compounds, which led to maximum projected supplemental fuel requirements. A third worst-case assumption was that the lowest capacity and lowest flowrate of any plant using a given manufacturing process was assumed in projecting product percent price increases due to control. This assumption led to higher estimates of percent price increase, due to economies of scale in control equipment capital costs for facilities with higher capacities and flowrates. In addition, as analysis was conducted of the sensitivity of percent product price increase to fluctuations in discount rates, natural gas prices, and offgas flowrates around expected values. Those specific chemical production processes which exceeded any of the economic feasibility criteria under the worst-case assumptions or under the sensitivity analysis were reanalyzed using a set of assumptions more representative of the characteristics of those processes. The results of the final economic analysis were that for each of the regulatory alternatives, none of the chemical production processes exceeded any of the economic feasibility criteria. No chemicals are expected to have a price increase which in the worst-case would exceed 5 percent. The price changes of the 36 chemicals, assuming control costs would be passed through totally, would range from 0 to a 3.1 percent increase except for maleic anhydride (benzene process), which showed an estimated 4.2 percent increase. New maleic anhydride plants are expected to employ the butane process (which showed an estimated 3.1 percent increase), instead of the benzene process, even in the absence of the proposed standard. Therefore, regardless of which alternative was selected as the basis for the proposed standard, it was determined that the costs of controls would be economically feasible for all chemicals covered by the proposed standard.

Selection of Basis for the Proposed Standard

The Clean Air Act requires that standards of performance be based on the best system of continuous emission reduction, considering costs, energy usage, and nonair health and environmental impacts ("best demonstrated technology" or BDT). As stated above, each regulatory alternative represents a distinct percentage of sources that would be required to reduce total organic (minus methane and ethane) emissions by 98 percentage or to 20 ppmv (limits reflecting use of thermal oxidation). By selecting one alternative, the Administrator selects the portion of projected new sources for which control by thermal incineration (under the conditions explained above) is BDT. For the remaining portion of projected new sources it is the Administrator's determination that BDT is no organic emission reduction from the baseline emission level.

As explained previously, none of these regulatory alternatives would either result in unreasonable energy or nonair environmental impacts or cause any of the chemical production processes to exceed any of the economic feasibility criteria. However, because the emission reduction achievable by applying incineration to sources is different under each of the alternatives, the Administrator undertook further analysis before selecting an alternative. This further analysis was undertaken to assure that the cost of the alternative

selected as the basis for the standard is reasonable, not only in terms of economic impacts, but also in terms of the emission reduction which would result. In this further analysis, the data presented in Table 1 were first considered. As shown in the table, those air oxidation facilities required to reduce VOC emissions under Alternative VI that would not have been controlled under Alternative V had a control cost per megagram of VOC reduced ranging from $5700 to $5,400,000. Those facilities controlled by Alternatives V and IV were also examined in a similar manner and showed control costs per megagram of VOC reduced in the ranges of $2700 to $5500 and $1900 to $2700, respectively. (These costs do not represent the actual amounts of money spent for any particular air oxidation facility. Rather, the costs are estimates which represent facilities likely to be built. The cost of VOC emission reduction systems will vary according to the chemical being produced, production equipment, plant layout, geographic location, and company preferences and policies.) However, the Administrator concluded that the cost of requiring control of any facility above the $1,900/Mg cutoff shown in Table 1 is unreasonably high compared to the emission reduction achieved. In the past, the maximum estimated cost per megagram of pollutant material removed (VOC, particulate matter, SO_2) has ranged from somewhat less than $1000 to more than $2000. This package has a maximum estimated cost per megagram of $1900. In prior source categories for which NSPS have been developed, VOC maximum estimated control costs have generally not exceeded $1000 per megagram. In this case, because of the presence of potentially toxic constituents in the discharge streams and the "worst case" character of the cost calculations, EPA believes the proposed standards are reasonable.

The maximum estimated cost in this package will not be viewed as a precedent for future actions. Instead, in the future, EPA will continue to evaluate each package on an individual basis.

Those air oxidation facilities required to reduce VOC emissions by 98 percent under Alternative III, that would not have been controlled under Alternative II, had a control cost per megagram of VOC reduced ranging from $1,400 to $1,900. Alternatives I and II would be less expensive than Alternative III, but would result in less emission reduction. Since the costs per unit emission reduction of Alternative III were judged to be reasonable, and since there were no other statutory factors, such as adverse economic impacts or adverse environmental impacts, for rejecting Alternative III, there was no reason to select Alternative I or II, either of which would result in less emission reduction.

In selecting Alternative III, the Agency noted that its average cost is only about $830 per megagram of VOC reduced. The Agency also considered that SOCMI is the largest stationary emission source of VOC and air oxidation is a major VOC emitting segment of SOCMI. Also, as detailed in the section entitled *TRE Index*, the costs shown in Table 1 do not take into account the ability of facilities to control emissions through adding product recovery and, in certain cases, to thereby avoid incineration costs. Due to this ability, the upper end of the cost per Mg emission reduction of Alternative III could be overstated by as much as $600/Mg. It is unlikely, therefore, that any air oxidation facility would have to spend the maximum cutoff cost per megagram of $1,900/Mg.

The Chemical Manufacturers' Association (CMA) presented, at a meeting of the National Air Pollution Control Techniques Advisory Committee on September 23, 1981, an analysis of the impacts of Alternative III, based on a set of assumptions concerning the rate of growth in the number of air oxidation sources which differs from those used by EPA. In projecting the number of new sources, CMA assumed that the number of affected facilities in the fifth year would be only those facilities for which construction or expansion had already been publicly announced. In general, CMA's projection leads to fewer new facilities, but with larger capacities and larger uncontrolled VOC emission rates. All other assumptions used in the CMA analysis (concerning the costs of equipment, operation and maintenance requirements, and related factors) were essentially the same as those used in the EPA evaluation of regulatory alternatives. The Agency examined CMA's analysis to determine if their results would alter the regulatory alternative selected as the basis for the standard. The annualized cost estimated by CMA's analysis of $22 million is greater than the $10 million annualized cost estimated by EPA. However, the projected emission reduction of 23,000 Mg/yr according to CMA's analysis is also larger than the 12,500 Mg/yr projected by the Agency. The economic impacts, such as price increases and impact of foreign competition, projected by EPA are independent of the alternative selected and would not be impacted by CMA's assumptions. CMA's analysis shows the average cost of incineration per unit of VOC destroyed to be $900/Mg, which is essentially the same as the average cost of incineration per unit of VOC destroyed estimated by EPA ($830/Mg). The highest cost to incinerate per Mg VOC destroyed for either analysis would be $1,900. The selection of Alternative III was not directly influenced by the number of sources which may be affected. Rather, the selection was based on the concept that there is a range of source characteristics within which costs, emission reductions, and other factors lead to the conclusion that control is reasonable. In other words, the CMA analysis would not have altered the selection of Alternative III as the basis for the proposed standard. The impacts of the proposed standard are judged to be reasonable based on either set of assumptions.

TRE Index. After selecting Alternative III as the basis of the proposed standard, it was necessary to develop a method for identifying those facilities covered by Alternative III which would be required to reduce emissions by 98 percent or to 20 ppmv, and those facilities not included in Alternative III, for which no emission reduction beyond product recovery would be required. The Agency, therefore, has included an equation in the regulation to calculate an index which is used to determine which affected facilities are required to reduce emissions by 98 percent or 20 ppmv. This index is termed total resource effectiveness (TRE). The equation includes the parameters used in calculating the costs considered in selecting Alternative III. These parameters are the offgas characteristics of flowrate, net heating value, total organics (minus methane and ethane) emission rate and corrosion properties (presence of chlorinated compounds). These parameters can be easily and objectively measured. The TRE value calculation allows the owner or operator of an affected facility to determine if that facility would be required to reduce emissions 98 percent or to 20 ppmv. The standardized calculation allows objective enforcement since all TRE values would be calculated based on the same parameters and calculated by the same method.

The TRE index of a process vent stream is calculated according to the following equation:

$$TRE = \frac{1}{E_{TOC}} \times [\, a + b\,(Q_s)^{0.88} + c\,(Q_s) + d\,(Q_s)\,(H_T) + e\,(Q_s)^{0.88}\,(H_T)^{0.88} + f\,(H_T)^{0.88}]$$

where:

TRE = Total resource-effectiveness index value.

Q_s = Vent stream flowrate (scm/min), at a standard temperature of 20°C.

H_T = Vent stream net heating value (MJ/scm), where the net enthalpy of per mole of offgas is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C, as in the definition of Q_s.

E_{TOC} = Hourly emissions of total organic compounds (minus methane and ethane) reported in kg/hr measured at full operating flowrate.

a, b, c, d, e, and f are coefficients.

The set of coefficients which apply to a process vent stream can be obtained from Table 1 of the regulation. These coefficients were derived directly from the cost and emission reduction equations associated with control of VOC emissions from air oxidation facilities by thermal oxidation. Table 1 of the regulation is divided into the five design categories for control equipment. These design categories differ in the amount of heat recovery achieved, in the type of heat recovery equipment used, and in the use of flue gas scrubbing for offgas containing chlorinated compounds. The amount and type of heat recovery used depends upon the offgas heating value.

The vent stream of an affected facility is considered "chlorinated" under the proposed standard if it is determined to contain a concentration of 20 ppmv (by compound) or greater of chlorinated compounds. This low 20 ppmv chlorination cutoff was chosen to avoid control cost and TRE underestimates. Even small amounts of chlorinated compounds may be corrosive, as well as difficult enough to incinerate that a temperature greater than 870°C is necessary to achieve 98 percent control. Therefore, it was judged essential to set a low cutoff, so that control cost and TRE would not be underestimated for any facility. The ethylene dichloride process is the only current air oxidation process with chlorinated vent streams. Because this process may have affected facilities subject to the proposed standards, the Administrator decided to set the chlorination cutoff at 10 percent of the lowest known total chlorinated compound concentration for any existing ethylene dichloride facility, or 20 ppmv.

Under each design category listed in Table 1 of the regulation, there are several intervals of offgas flowrate. Each flowrate interval is associated with a different set of coefficients. The first flowrate smaller than that corresponding to the smallest control equipment system easily available without special custom design. The remaining flowrate interval in each design category applies to vent streams with a flowrate intervals in each design category apply to vent streams which would be expected to use one, two, three, four, or five sets of control equipment, respectively. These flowrate intervals are distinguished from one another because of limits to prefabricated equipment sizes.

The TRE index cutoff value associated with Alternative III as calculated by the above equation is 2.2. Affected air oxidation facilities with a TRE index of less than or equal to 2.2 would be required to reduce emissions by 98 percent or to 20 ppmv, while affected facilities with a TRE index above 2.2 would not be required to combust VOC emissions.

The use of a TRE index cutoff value will also encourge the use of product recovery techniques or process modification in an effort to raise the TRE index value above the 2.2 cutoff. The parameters used to calculate the TRE index are measured at the outlet of the final piece of product recovery equipment. Additional product recovery can be used to change the values of the parameters (e.g., decrease the emission rate) and increase the TRE index value. The total cost to a facility of improved product recovery to exceed the TRE index cutoff would probably be much lower than the total cost of thermal oxidation to achieve 98 percent reduction. It would, therefore, be economically advantageous for such a facility to choose to improve product recovery. However, the necessary reduction in emission rate to exceed the TRE index cutoff might also be less than 98 percent. Therefore, the actual cost per metric ton for some facilities choosing to improve product recovery might exceed the projected cost per metric ton of thermal oxidation. Nevertheless, such a facility would probably choose to improve product recovery rather than incinerate due to the lower costs.

Compounds Used in Determining Compliance. The proposed standards are intended to reduce emissions of VOC through the application of best demonstrated technology (BDT) (considering costs and other impacts), and the emission limits in the standards are designed to reflect the performance of BDT. The best demonstrated technologies applicable to air oxidation processes do not selectively control VOC (that is, the proportion of the organics that is regarded as photochemically reactive), but rather these technologies control all organic compounds.

Moreover, the test methods applicable for determining compliance with standards based on those technologies measure total organic compounds, minus methane and ethane. Also, the Agency derived the emission limits for distillation operations from data gathered using test procedures that measure total organic compounds, minus methane and ethane.

To reflect accurately the performance of the technologies selected as BDT and to make the emission limits consistent with the data and test methods from which the limits were derived, the Agency has expressed the standards in terms of total organic compounds, minus methane and ethane. For the same reason, the test procedure in the proposed standards prescribes measurement of total organic compounds, excluding methane and ethane. In short, EPA is relying on control of total organic compounds, minus methane and ethane, as the best demonstrated surrogate for controlling volatile organic compounds, which react to form ozone in the atmosphere.

Modification/Reconstruction Consideration

The proposed standard would apply to all affected facilities, which commenced construction, reconstruction, or modification after the date of proposal of the NSPS. Modification is defined in 40 CFR 60.14 as "any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility, or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted." (Section 60.14 lists a few cases which would not be considered modifications even if emissions increased.) Reconstruction, as defined in 40 CFR 60.15, occurs when components of an existing facility are replaced to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the

fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.

Potential modifications involving SOCMI air oxidation processes include catalyst substitution, process equipment changes, and combinations of these changes.

Catalyst substitutions can be made to improve product mix, reduce operating costs, or increase conversion rates. A change in catalysts may cause significant changes in the quantity of VOC emissions. In addition, these changes could require major modifications in the reactor system and auxiliary process equipment.

Changes in air oxidation process equipment could result in increased VOC emissions and, if so, could constitute a modification. Examples include an increase in the size of the reactor, addition of a reactor, and a change in the product recovery system from an absorber to a condenser. However, any changes in product recovery equipment would be intended to increase product recovery, and, therefore, VOC emissions would be expected to decrease.

In many cases, a combination of changes would be chosen based on the most advantageous economics. One example of such a modification would be the simultaneous change of the reactor conditions and catalyst.

These type of changes are real alternatives for many air oxidation chemical manufacturing industries. However, they generally involve substantial changes in catalyst, reactor conditions, or product separation/purification equipment. Because the expected type of changes would be so substantial, potential modifications would probably be infeasible due to the costs involved. Although much effort will be directed toward identifying cheaper, more readily available feedstocks, chemical manufacturers probably would choose to build new facilities to use the cheaper feeds rather than go to the expense of radically modifying existing facilities. Therefore, there would probably be very few air oxidation facilities which would become subject to the proposed standard as a result of the types of changes discussed above.

No existing facility is expected to undergo sufficient replacement of components to be considered a reconstructed facility. Reactors and pieces of product recovery equipment within an affected facility would, in general, have different ages as well as different lifetimes. Moreover, such types of equipment are rarely replaced. Therefore, it is likely that a considerable interval of time would separate replacements of individual reactors or product recovery devices. For reasons stated in the preamble to the proposed standard for metallic minerals which was proposed on August 24, 1982 (47 FR 36867), if the cumulative fixed capital cost of replacements commenced within any 2-year period exceeded 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, such replacements could constitute reconstruction, as defined in that section (see § 60.616(a) of this proposed standard).

Selection of Monitoring Requirements and Test Methods

98 percent/20 ppmv Emission Limit. Numerous methods exist for the measurement of organic emissions. Among these methods are gas chromatography (GC), direct flame ionization detection (FID), and EPA Reference Method 25 (EPA 25)—Determination of Total Gaseous Non-Methane Organic Emissions as Carbon. Each method has advantages and disadvantages. Of the three procedures, GC has the distinct advantage of identifying and quantifying the individual compounds present in the emissions. The major disadvantages with this procedure are that GC systems are expensive and determination of the column required and analysis of samples can be time consuming.

The direct FID technique is the simplest procedure. However, the FID alone responds differently to various organic compounds and can yield highly biased results depending upon the compounds involved. Another disadvantage of the FID alone is that a separate methane measurement is required to determine nonmethane organics. The direct FID procedure alone does not identify or quantify individual compounds.

Method 25 sampling and analysis provides a single nonmethane organic measurement on a carbon basis: this is convenient for establishing control device efficiencies on a consistent basis. However, this method does not provide any qualitative or quantitative information on individual compounds present. For this reason, Method 25 was rejected as the Reference Method for determining compliance with the proposed standard.

The combined GC/FID is the proposed required test procedure for determining thermal or catalytic oxidizer control efficiency for air oxidation processes. A general GC/FID procedure (Method 18) is being promulgated with the SOCMI fugitive NSPS. Methane and ethane are measured separately by Method 18. Details concerning the use of this methodology, including sampling, analysis, preparation of standards, calibration procedures, and reporting of results are discussed in Method 18, Measurement of Gaseous Organic Compound Emissions by Gas Chromatography.

The owner or operator of a facility using any combustion device (other than steam generating units, such as boilers or process heaters, with a design capacity of 44MW or greater) to comply with the proposed emission limit would be required to determine compliance according to Reference Method 18 during any performance test. Reference Method 1 or 1A would be required as appropriate to be used for selection of the sampling site. The control device inlet sampling site for determination of reduction efficiency would be required to be prior to the inlet of any combustion device and after all product recovery units.

If any nonair-oxidation offgas steam were normally routed through the product recovery train or directly to the control device of the affected facility, the proposed standards would permit such a stream to be routed normally during any performance test to determine compliance with the proposed reduction requirement. The Agency considered requiring such streams to be rerouted or turned off, in order to assure that 98 percent reduction, or reduction to 20 ppmv, would be achieved for the air oxidation stream itself. However, the Agency determined that if a performance test conducted on such a facility while routing its nonair-oxidation offgas normally showed compliance with the proposed emission limit, that limit would also be achieved by the combustion device when only the air oxidation process stream is routed through it, provided that the combustion device operating parameters, such as temperature, remained unchanged. Therefore, the Agency concluded that requiring the nonair-oxidation stream to be rerouted or turned off during a performance test would be unnecessary.

The air oxidation offgas stream of an affected facility might be normally routed through nonair-oxidation process equipment, as a result of which its composition or flowrate might be altered. In such a case, the proposed standards would permit the air oxidation stream to be routed normally during any performance test to determine compliance with the proposed emission limit. The Agency considered

requiring that such equipment be bypassed during a performance test, in order to assure that the proposed emission limit would be achieved for the unaltered air oxidation stream itself. However, the Agency determined that if a performance test conducted on such a facility while routing its air oxidation offgas normally showed compliance with the proposed emission limit, that limit would also be achieved by the combustion deviced if the nonair-oxidation equipment were bypassed, provided that the combustion device operating parameters, such as temperature, remained unchanged. Therefore, the Agency concluded that such a requirement would be unnecessary.

Steam generating units, such as boilers, or process heaters might be used for combustion of the VOC in an air oxidation process stream. The Agency believes that steam generating units with a design heat input capacity of 44 MW or greater achieve a reduction efficiency of 98 percent or reduction to 20 ppmv. Therefore, the Agency believes that an initial measurement of control efficiency would not be necessary. As explained previously in the discussion of combustion kinetics given in the section entitled *Control Techniques*, a firebox temperature of 1100°C and 1 second residence time represent the conditions that might in the worst case be necessary to achieve 98 percent reduction, even if the VOC were chlorinated. Steam generating units with a design capacity of 44 MW or greater are operated at temperatures and residence times greater than 1100°C and 1 second, respectively. Other than an adequately high temperature and residence time, the two primary conditions necessary for high combustion device control efficiency are stable flow rate and adequate mixing of gases. It is to the economic advantage of the owners of facilities using such large steam generating units to design and operate them with stable flowrates to avoid upsets. For the same reason, such devices would be designed and operated with adequate mixing of gases to maximize the amount of combustion, thereby maximizing the steam generation rate. For these reasons, the Administrator has decided that installing a steam generating unit, with a design heat input capacity of 44 MW or greater, to control VOC emissions from an air oxidation process, is an acceptable means of demonstrating compliance with the proposed standards. Therefore, in accordance with § 60.8(b), the Administrator has waived the requirement for a performance test on such devices.

The control equipment used to comply with the proposed emission limit needs to be properly maintained and operated if 98 percent reduction, or reduction to 20 ppm are to be achieved on a lasting basis. Monitoring requirements are generally used to ensure such proper operation and maintenance. Three methods of monitoring to ensure such proper operation and maintenance of control equipment used to comply with the proposed VOC emission limit were considered. These methods were continuous emission monitoring, a combination of biannual performance testing and biannual inspection and maintenance, and continuous measurement of important combustion control device parameters, such as combustion temperature or vent stream flowrate.

Continuous combustion control device inlet and outlet emission monitoring would be the preferred method of monitoring, because it would be a continuous, direct measure of actual emissions. However, since this would require two monitors, it would be relatively expensive.

Biannual performance testing would provide a periodic, direct measure of actual emissions. The associated biannual inspection and maintenance program would catch drops in combustion device performance due to existing or impending equipment failures. However, repeated, biannual performance testing with biannual equipment inspection and maintenance would be expensive with an estimated cost of $25,000 per test. Therefore, the Administrator has decided not to require biannual performance testing with an associated biannual inspection and maintenance program.

Provided that combustion parameters which accurately reflect the level of combustion device efficiency can be identified and continuously monitored, monitoring of such parameters alone would have several advantages, such as low cost and high reliability. However, a disadvantage of combustion parameter monitoring alone is that the correlation of the parameters with the numerical emission limit is not exact. However, exact correlation is not necessary if the parameter monitored would demonstrate proper operation and maintenance of the control device.

The combustion device operating parameters that affect incinerator performance were analyzed. These variables are temperature, mixing, type of compound, residence time, inlet concentration, and flow regime. Of these variables, the last two were judged to have only a small impact on incinerator performance. Residence time is essentially set after oxidizer construction unless the vent stream flowrate is changed. At temperatures above 760°C, the compound type has little effect on combustion efficiency. The two remaining variables were then analyzed in more detail to define their impact on performance and the ability to monitor them.

Temperature was analyzed first. Test results and theoretical calculations show that lower temperatures can cause significant decreases in control device efficiency. Test results also indicate that temperature increases can also adversely affect control device efficiency, apparently by decreasing the thoroughness of mixing of offgas, burner gases and combustion air. In terms of cost, temperature monitors are inexpensive, costing less than $5,000 installed with strip charts, and are easily and cheaply operated. Given the large effect of temperature on efficiency and the low cost of temperature monitors, this variable is clearly an effective parameter to monitor.

Mixing of process offgas, combustion air, and hot exhaust products from the burner was the next combustion control device parameter to be analyzed. The most likely item to affect mixing, given a constant temperature and an already constructed incinerator, would be flow. No direct field data is available on the effect of flow on mixing efficiency. However, it is recognized that the flow rate of vent streams will vary with process conditions, from zero, when the process is down, to some maximum value. The Agency considered requiring process records be kept which would relate vent stream flow rates to acceptable combustion device parameters. However, the Agency was unable to identify a meaningful relationship between flow rate and VOC destruction efficiency. Furthermore, based on engineering judgment, flow rate would not be expected to have much affect on the large combustion devices likely to be encountered in air-oxidation processes.

Because of the resource burden associated with the other two alternatives (continuous VOC monitoring and biannual performance testing), and since temperature was identified as a combustion parameter which can be cheaply and reliably monitored, this third alternative was chosen. Temperature would be required to be measured during the original (or most recent) performance test. Temperature would then be monitored

to determine if it deviated from the values measured during the performance test. The proposed standard would, therefore, require the owner or operator of an affected facility using a combustion device (except for a stream generating unit with a design heat capacity of 44 MW or greater) to comply with the proposed VOC emission limit to install, calibrate, maintain, and operate according to manufacturer's specifications a temperature measurement device. This device would be required to be equipped with a continuous recorder and have an accuracy of one percent of the temperature being measured, expressed in degrees Celsius, or ±2.5°C, whichever is greater. If a thermal incinerator or stream generating unit were used, the device would be required to be installed in the firebox. If a catalytic oxidizer were used, the temperature measuring device would be required to installed in the gas stream immediately before and after the catalyst bed.

Monitoring of temperature would not be required for steam generating units with a design heat capacity of 44 MW or greater. These devices always operate at high temperatures (<1100°C) and stable flowrates to avoid upsets and to maximize the steam generation rate. The maintenance of records would be required, however, which would indicate the periods of operation of the steam generating unit. The nature of the records to be kept to comply with this requirement are left to the discretion of the owner or operator of the facility, but they must be readily available for inspection.

TRE Cutoff. Calculation of the total resource-effectiveness (TRE) index value for an affected facility is dependent upon measurement of the offgas volumetric flowrate, net heating value, total organic (minus methane and ethane) emission rate, and corrosion properties (presence or absence of chlorinated compounds). These measured values are used to select the corresponding coefficients and then inserted into an equation specified in the proposed standard for calculation of the TRE index. Reference Method 1 or 1A would be required as appropriate to be used for selection of the site for measuring the offgas flowrate and molar composition. The sampling site would be required to be prior to any post-reactor dilution of the stream with air, prior to any post-reactor introduction of chlorinated compounds into the stream, and also prior to the inlet of any combustion device. Subject to the requirements just mentioned, the sampling site would also be required to be dowstream of all product recovery equipment. The volumetric flowrate would be required to be determined according to Reference Method 2, 2A, 2C, or 2D as appropriate. The molar composition of the offgas stream, including the total molar concentration of chlorinated compounds, would be required to be calculated according to Method 18, Measurement of Gaseous Organic Compound Emission by Gas Chromatography. Reference Method 10 would be required to be used for measurement of carbon monoxide concentration. This measured carbon monoxide concentration would be required to be converted from a dry basis to a wet basis by use of an equation specified in the proposed regulation. The water vapor concentration of the vent stream would be required to be calculated according to Reference Method 4 for inclusion in the carbon monoxide concentration correction equation.

The net heating value of the process vent stream (25°C, 760 mm Hg) would be required to be calculated according to an equation specified in the regulation. This equation would make use of the molar composition of the offgas stream, as measured by Method 4, Method 10, and Method 18. The net heat of combustion of each offgas component would be required to be determined using ASTM D2382-76 if published values are not available or cannot be calculated. This method of determining net heating value was chosen because it would not require a separate test procedure from that required for determination of VOC reduction efficiency and offgas chlorination. Moreover, the Agency believes that the proposed method for determining net heating value would be more accurate than any available direct experimental measure, such as bomb calorimetry.

The total organic (minus methane and ethane) mass emission rate of the process vent stream would also be required to be calculated according to an equation specified in the regulation. This equation would make use of the molar composition of the offgas stream, as measured by Method 18, and of the volumetric flowrate, as measured by Method 2. The reasons for the choice of Method 18 for determination of organic compounds emission rate are discussed above in the section entitled *98 Percent 20 ppmv Emission Limit.*

A nonair-oxidation offgas stream might be normally routed through the product recovery train of the affected facility. Such a stream would be required by the proposed standards to be rerouted or turned off during any performance test conducted to determine compliance with the TRE cutoff requirement, until the measurements for determining offgas flowrate and molar composition had been made. This requirement is included in the proposed standards to assure that the TRE index value of the air oxidation stream only is calculated. The equation for calculating the TRE index value has been developed based on air oxidation streams and the 2.2 TRE index value cutoff included in the standards was selected based on air oxidation streams. Using flowrates and molar compositions of nonair-oxidation streams would distort the calculated TRE index value.

The air oxidation offgas stream of an affected facility might be normally routed through nonair-oxidation process equipment. In such a case, the proposed standards would require that such monair-oxidation process equipment be bypased by the air oxidation vent stream during any performance test conducted to determine compliance with the TRE cutoff requirement, until the measurements for determining offgas flowrate and molar composition had been made. This requirement has been included in the proposed standards to assure that the TRE index value is calculated for an air oxidation stream that has not been altered by routing it through nonair-oxidation process equipment. As discussed previously, the TRE equation for calculating the TRE index value has been developed based on air oxidation streams and the 2.2 TRE index value cutoff included in the proposed standards was selected based on air oxidation streams. Using flowrates and molar compositions that have been altered by nonair-oxidation process equipment would distort the calculated TRE index value.

After an initial performance test is conducted to determine compliance with the proposed TRE cutoff value, process modifications or improper operation or maintenance of product recovery equipment could lead to higher emissions and a true TRE value not in compliance with the cutoff. Therefore, three methods of monitoring for facilities using product recovery to meet the proposed standards were considered. These methods were continuous vent stream molar composition and flowrate monitoring, a combination of biannual performance testing of the TRE index value of the facility with continuous monitoring of selected operating parameters of the final piece of product recovery equipment in the affected facility train , and continuous monitoring of operating parameters only.

Continuous monitoring of the vent stream flowrate and molar composition would be the preferred method if feasible, because it would be a continuous, direct measure of proper operation of the product recovery device. However, because of the many different VOC compounds in air oxidation vent streams, no continuous offgas molar composition monitor has been demonstrated. Current offgas molar composition monitoring systems are not simple and automated, but extremely complex and labor-intensive. Therefore, the EPA has determined that continuous monitoring of offgas molar composition and flowrate for determination of proper operation and maintenance is infeasible.

Biannual performance testing would provide a periodic, direct measure of compliance with the TRE cutoff provision of the prosposed standard. However, biannual testing, particularly the offgas molar composition monitoring measurement, would be expensive, with an estimated cost of $25,000 per test. Therefore, the Administrator has determined that the cost of biannual performance testing is not reasonable, considering other reliable options which are less expensive.

Provided that product recovery equipment operating parameters which accurately reflect the level of product recovery device efficiency and, therefore, the offgas molar composition could be identified and continuously monitored, monitoring of such parameters alone would be preferable.

Therefore, the operating parameters of the three types of product recovery equipment commonly used in air oxidation processes were analyzed for correlation with product recovery device efficiency. The three commonly used types of product recovery equipment are absorbers, condensers, and carbon adsorbers.

For an absorber, two operating parameters were identified as the primary determinants of product recovery efficiency: absorbing liquid temperature and specific gravity (or some other parameter used by a facility to measure absorbing liquid saturation). In the absence of the proposed standard, facilities employing an absorber for product recovery would, in general, continuously monitor some parameter related to the degree of saturation of absorbing liquid with recovered material. Specific gravity is one such parameter which is frequently monitored. Absorbing liquid temperature monitors and specific gravity measurement devices are available at a reasonable cost. The estimated one-time combined capital investment for such equipment is $8,000. These absorption parameters would be required to be measured during each performance test. (If approved by the enforcing Agency, an alternative parameter which would indicate the degree of absorbing liquid saturation could be measured during each performance test.) These absorption parameters would then be monitored to determine if any value had changed since the performance test. This monitoring would indicate whether the absorber were being properly operated and maintained. Therefore, an operator of an affected facility for which an absorber was the final unit in the product recovery train would be required to install, calibrate, maintain, and operate according to manufacturer's specification an absorbing liquid temperature monitor and specific gravity measurement device (or an alternate device which would measure the degree of absorbing liquid saturation, if approved by the enforcing agency), each equipped with a continuous recorder.

For a condenser, the exit (product side) temperature was identified as the primary determinant of product recovery efficiency. Condenser temperature monitors are available at a reasonable cost. The estimated one-time capital investment for such equipment is $3,000. The condenser exit (product side) temperature would be required to be measured during each performance test. The temperature would then be monitored to determine if the value had changed since the most recent performance test. This monitoring would indicate whether the condenser were being properly operated and maintained. Therefore, an operator of an affected facility for which a condenser were the final unit in the product recovery train would be required to install, calibrate, maintain, and operate according to manufacturer's specifications a condenser temperature monitor equipped with a continuous recorder.

For a carbon adsorber the carbon bed temperature (after regeneration and completion of any cooling cycles), as well as the amount of steam used to regenerate the adsorption bed, were identified as indicators of product recovery efficiency. Steam flow meters which indicate the quantity of steam used over a period of time, and bed temperature monitors are available at a reasonable cost. The estimated one-time capital investment for such equipment is $10,000. These adsorption parameters would be required to be measured during each performance test. These adsorption parameters would then be monitored to determine if either value had changed since the most recent performance test. This monitoring would indicate whether the carbon adsorption unit were being properly operated and maintained. Therefore, an operator of an affected facility for which a carbon adsorber is the final unit of the product recovery train would be required to install, calibrate, maintain, and operate according to manufacturer's specifications an integrating steam flow meter, and a carbon bed temperature measurement device, each equipped with a continuous recorder. Some new carbon adsorbers may include vent stream VOC concentration monitors in order to guide operators in maximizing recovery of raw material or products. No widely accepted performance specifications have been developed for such organics concentration monitors and therefore these devices are not being required at the present time. However, such devices may be approved by the Administrator on a case-by-case basis. If an organics concentration measuring device is used, but a recording device is not installed so that a permanent time record of the measurement is produced, then the vent stream must be sampled at the end of the adsorption cycle (at least once during every four hours of operation) and the concentration recorded.

Certain facilities, as discussed previously, would be required to reroute or turn off nonair-oxidation streams before measuring the appropriate parameters for calculating the TRE index value. However, the value of the parameter(s) to be monitored could vary significantly depending on whether the nonair-oxidation streams are routed through the product recovery device. Therefore, the facility would be required to return to normal routing of these nonair-oxidation streams after the parameter(s) for calculating the TRE index value have been measured but before making the performance test measurement of the parameter(s) to be monitored continuously. The value(s) of the parameter(s) to be monitored continuously would be indicative of proper operation and maintenance during normal operation of the product recovery device. It is therefore the most appropriate reference value against which to compare results of post-performance test continuous parameter monitoring.

The same procedure would be followed for facilities that are required to bypass nonair/oxidation process equipment during the performance test. Before making the initial measurement of the parameter(s) to be monitored, the facility would be required to return to normal routing of the air oxidation

stream through any nonair/oxidation process equipment. This value of the parameter(s) to be monitored would be indicative of proper operation and maintenance during normal operation of the product recovery device.

The enforcement agency would specify on a case by case basis appropriate monitoring procedures or requirements where the owner or operator of an affected facility uses emission control or product recovery techniques other than those specified to comply with the proposed standard.

Selection of Reporting and Recordkeeping Requirements

The General Provisions of Part 60 require submittal of several one-time notifications for occurrences such as construction, modification, reconstruction, scheduled dates for performance tests, and performance test results. Owners and operators of steam generating units with a design heat capacity of 44 MW or greater would not report performance test results, since the proposed standard would waive the requirement of such a test. Instead, operators would be required to file an initial report stating the design heat input capacity of the steam generating unit to be used.

The proposed standards exempt air oxidation facilities from the quarterly reports required by the General Provisions. However, records of startup, shutdown, and malfunction would still be required. Also, records indicating whether control equipment is being properly operated and maintained would be required.

Records indicating proper operation and maintenance would be based on the monitoring of control device or product recovery device parameters discussed in the previous section. Two types of records would be required. The first would be the monitoring results themselves. This information can be automatically recorded, and, therefore, essentially the only labor necessary for keeping these records would consist of filing automatically recorded parameters. The second type of record would be a tabulation of periods when the measurements of these automatically recorded parameters significantly deviated from measurements of the same parameters during the most recent performance test. Although this requires more effort, it is a necessary step for both the owner or operator and enforcement agency to ensure that the control equipment is being properly operated and maintained. This information would be necessary for the owner or operator to know when to make necessary corrections to the control equipment. For this second type of record, it would be necessary for the owner or operator to record control device or recovery equipment operating parameters, as appropriate, during all performance tests and keep these records for purposes of comparison. The owner or operator would not be required to record all deviations from these measurements, but only the deviations listed below for the different types of control devices.

Where a combustion system is used to comply with the proposed numerical emission limit, the proposed standards would require recording of the following information regarding periods of operation during which the parameter boundaries established during the most recent performance test are exceeded: (1) For a thermal oxidizer or steam generation unit with a design heat input capacity of less than 44 MW, all 3-hour periods during which the average firebox temperature was more than 28°C (50°F) below the average firebox temperature measured during the most recent performance test; (2) for a catalytic oxidizer, all 3-hour periods of operation during which the average temperature before the catalyst bed was more than 28°C (50°F— below the average temperature of the device during the most recent performance test, and all 3-hour periods of operation during which the average temperature difference across the catalyst bed was less than 80 percent of the average temperature difference measured during the most recent performance test; and (3) for steam generating units with a design heat input capacity greater than 44 NW, all periods of operation of the stream generating unit. All records would be required to be kept up to date, and in readily accessible files for 2 years. The parameter boundaries discussed above would allow for normal fluctuations in operation of the equipment monitored. The reduction efficiency of the control device would not be affected by such normal fluctuations.

Where a product recovery system is used to comply with the proposed TRE index value, the proposed standards would require recording of two types of information. The first requirement would be to maintain records of any change in production capacity, feedstock type or catalyst type, or of the replacement, removal, of addition of product recovery equipment. When any such change occurs, the TRE index value would be recalculated based on the best engineering estimates of the effects of the change or on emission test data. A record shall be maintained of the recalculated TRE index value. If the recalculated TRE index value for the facility is less than 2.2, the owner or operator shall demonstrate compliance with the 98 percent or 20 ppmv emission limits. Notice of any performance test shall be given to EPA as required by the General Provisions.

The second provision would require recording of the following information regarding periods of operation during which the operating parameter boundaries established during the most recent performance test for the final product recovery unit are exceeded: (1) Where an absorber was the final unit in the product recovery system, all 3-hour periods of operation during which the average absorbing liquid termperature was more than 11°C (20°F) above that measured in the most recent performance test, and all 3-hour periods of operation in which the absorbing liquid specific gravity was more than 0.1 unit above or below that measured in the most recent performance test (if the enforcing agency approves an alternative parameter to specific gravity for monitoring by a facility, that agency shall define appropriate parameter boundaries and periods of operation during which they are exceeded); (2) where a condenser was the final unit in the product recovery system, all 3-hour periods of operation during which the average temperature of the recovered liquid was more than 3°C (5°F) above the average operating temperature during the most recent performance test; (3) where a carbon absorber was the final unit in a product recovery system all carbon bed regeneration cycles during which the total mass of steam used was less than the total mass of steam used in most recent performance test, and all carbon bed regeneration cycles during which the temperature of the carbon bed (after regeneration and all cooling cycles) was more than 10 percent greater than that measured in the most recent performance test. If the Administrator approves the use of an organics monitor, all 3-hour periods of operation during which the average concentration of VOC in the carbon adsorber exhaust gases indicated by the continuous monitoring system is more than 50 parts per million by volume and more than 20 percent greater than the exhaust gas concentration measured by the monitoring system during the most recent performance test shall be recorded. (Such a discrepancy would indicate improper operation of the carbon adsorption system.) All records would be required to be kept up to date, and in readily accessible files for 2 years. The parameter boundaries discussed above would allow for normal

fluctuations in operation of the equipment monitored. The TRE value for the facility would not be affected by such normal fluctuations.

In addition to the one-time notifications and performance test reports discussed above, semi-annual reporting of recorded data would be required for instances where monitored parameters exceed the allowable limitations set forth in the standards. These data include the operating parameters cited above for combustion devices and for product recovery systems. Other instances that would be reported semi-annually are periods when steam generating units used for thermal oxidation are not operating and when changes in a product recovery system cause the TRE index value to be recalculated. The requirement for semi-annual reporting is waived for affected facilities in States where the program has been delegated if EPA, in the course of delegation, approves reporting requirements or an alternative means of source surveillance adopted by the State. Such affected facilities would be required to comply with the requirements adopted by the State.

Impacts of Reporting and Recordkeeping Requirements

The information provisions associated with this proposed rule (40 CFR 60.7 and 40 CFR 60.615) have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980 U.S.C. 3501 *et seq.* Comments on these requirements should be submitted to the Office of Information and Regulatory Affairs of OMB—marked Attention Desk Officer for EPA. The final rule package will respond to any OMB or public comments on the information collection provisions. During the first 2 years of this regulation the average annual burden of the reporting and recordkeeping requirements would be 3.5 person-years, based on an average of 10 respondents per year.

Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the **ADDRESSES** section of the preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section address given in the **ADDRESSES** section of the preamble.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (see **ADDRESSES** section of this preamble).

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered in the development of this proposed rulemaking. The principal purposes of the docket are: (1) To allow interested parties to readily identify and locate documents so that they can effectively participate in the rulemaking process; and (2) to serve as the record in case of judicial review [except as noted in Section 307(d)(7)(A)].

Miscellaneous

As prescribed by Section 111, establishment of standards of performance for SOCMI air oxidation processes was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that SOCMI sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the proposed test methods.

This regulation will be reviewed within 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceablity, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under Section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to insure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the background information document.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because: (1) The national annualized compliance costs, including capital charges resulting from the standards total less than $100 million; (2) the standards do not cause a major increase in prices or production costs; and (3) the standards do not cause significant adverse effects on domestic competition, employment, investment, productivity, innovation or competition in foreign markets. As explained in the section entitled "Selection of Basis for the Proposed Standard," cost per megagram of emission reduction was the primary factor considered in selecting the alternative upon which the proposed standard is based.

This regulations was submitted to the Office of Management and Budget (OMB) for review as requird by Executive Order 12291. Any comments from OMB to EPA and any EPA response to those comments are included in Docket Number A-81-22. The docket is available for public inspection at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Regulatory Flexibility Analysis Certification. The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to current Small Business Administration guidelines, a small business in the air oxidation industry is one that has 1000 employees or less. Currently only 4 percent of existing air oxidation companies (three companies) employ less than 1000 people. Since Section 111 standards apply only to newly constructed, modified, and reconstructed facilities, and no modified or reconstructed facilities are expected, nor are any of these small air oxidation companies likely to expand by adding new units, none of these small companies are expected to be subjected to the proposed standards. The economies of scale that exist in this industry hinder the entrance of small businesses. Furthermore, if a company has the capital available to enter the industry, the NSPS will require only a small percentage increase in the capital required for the project. No new, modified, or reconstructed small air oxidation facilities will be adversely

affected. This conclusion is based on the fact that, in doing the economic analysis for this proposal, the price increase and profitability impacts have been estimated from the perspective of the smaller air oxidation facilities in operation.

Therefore, the finding that producers of air oxidation chemicals, under a worst-case scenario, would be able to pass through NSPS compliance costs to their customers while keeping the price increase of their product under 5 percent accurately reflects the impacts for small air oxidation companies.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal, Copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel sulfuric acid plants, Waste treatment and disposal, Zinc, Tires, Incorporation by reference, Can surface coating, Sulfuric acid plants, Industrial organic chemicals, Organic solvent cleaners.

Dated: October 11, 1983.

William D. Ruckelshaus,

Administrator.

PART 60—[AMENDED]

It is proposed that 40 CFR Part 60 be amended as follows:

1. A new Subpart III is added as follows:

Subpart III—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

Sec.

60.610 Applicability and designation of affected facility.
60.611 Definitions.
60.612 Standards.
60.613 Monitoring of emissions and operations.
60.614 Test methods and procedures.
60.615 Reporting and recordkeeping requirements.
60.616 Reconstruction.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, 42 U.S.C. 7411, 7601(a), and additional authority as noted below.

Subpart III—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

§ 60.610 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to affected air oxidation facilities. An affected facility is any individual reactor-product recovery train consisting of an individual product recovery system receiving offgas from at least one air oxidation reactor, along with all air oxidation reactors feeding offgas into this system. Each air oxidation reactor not feeding offgas into a product recovery system would constitute a separate affected facility.

(b) Any facility under paragraph (a) of this section that commences construction, modification, or reconstruction after October 21, 1983, would be subject to the requirements of this subpart.

Note.—The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of total organic compounds, measured as total organic compounds less methane and ethane. This emission limit reflects the performance of BDT.

§60.611 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in Subpart A of Part 60, and the following terms shall have the specific meanings given them.

Air Oxidation Process means a unit process, including ammoxidation and oxychlorination unit process, that uses air, or a combination of air and oxygen, as an oxygen source in combination with one or more organic reactants to produce one or more organic compounds.

Air Oxidation Reactor-Product Recovery Train means an individual product recovery system receiving offgas from at least one air oxidation reactor, along with all air oxidation reactors feeding offgas into this system.

Air Oxidation Reactor means any device or process vessel in which one or more organic reactants are combined with air, or a combination of air and oxygen, to produce one or more organic compounds. Ammoxidation and oxychlorination reactions are included in this definition.

By Compound means by individual stream components, not carbon equivalents.

Chlorinated Process Vent Stream means any process vent stream determined to have a total concentration (by volume) of compounds containing chlorine of 20 ppmv (by compound) or greater.

Process Vent Stream means any gas stream, containing nitrogen which was introduced as air to the air oxidation reactor, released to the atmosphere directly from any air oxidation reactor-product recovery train or indirectly, after diversion through other process equipment.

Product Recovery System means an individual unit or series of material recovery units, such as absorbers, condensers, and carbon adsorbers, which recovers total organic compounds (less methane and ethane) from a process vent stream for commercial or industrial use or reuse.

Steam Generating Unit means any furnace, boiler, process heater, or other device used for combusting fuel for the purpose of producing steam or process heat (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; waste-heat boilers are not included).

Total Organic Compounds means those compounds measured according to the procedures in § 60.614.

Total Resource-Effectiveness (TRE) Index Value means a measure of the supplemental total resource requirement per unit reduction of total organic compounds (excluding methane and ethane) associated with an individual air oxidation process vent stream, based on offgas flowrate, emission rate and total organic compounds (excluding ethane and methane), net heating value, and corrosion properties (whether or not the vent stream is halogenated), as quantified by the equation given under § 60.614(b)(5).

§ 60.612 Standards.

On or after the date on which the performance test is required by § 60.8, each owner or operator subject to the provisions of this subpart shall comply with one or the other of the following for each process vent stream:

(a) Reduce emissions of total organic compounds (less methan and ethane) by 98 weight percent, or to a total organic compound (less methane and ethane) concentration of 20 ppmv (by compound) on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(b) Maintain a total resource-effectiveness (TRE) index value greater than 2.2 without use of combustion devices.

§ 60.613 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses a combustion device [except for a steam generating unit with a design heat input capacity of 44 MW (150 Btu/hr) or greater] to seek to comply with the total organic compound emission limit specified under § 60.612(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications a temperature measurement device equipped with a continuous recorder and having an accuracy of 1 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C, whichever is greater.

(1) Where a combustion device other than a catalytic oxidizer is used, a temperature measurement device shall be installed in the firebox.

(2) Where a catalytic oxidizer is used, temperature measurement devices shall be installed in the gas stream immediately before and after the catalyst bed.

(b) The owner or operator of an affected facility that seeks to demonstrate compliance with the TRE index value limit specified under § 60.612(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final unit in a system, a scrubbing liquid temperature monitor having an accuracy of 1 percent of the termperature being measured expressed in degrees Celsius or ±2.5°C, whichever is greater, and a specific gravity measurement device having an accuracy of ±0.02 specific gravity unit, each equipped with a continuous recorder.

(2) Where a condenser is the final unit in a system, a condenser exit (product side) temperature monitor equipped with a continuous recorder and having an accuracy of 1 percent of the temperature being measured expressd in degrees Celsius or ±2.5°C, whichever is greater.

(3) Where a carbon adsorber is the final unit in a system, an integrating steam flow meter having an accuracy of ±10 percent, and a carbon bed temperature monitor having an accuracy of 1 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C, whichever is greater, both equipped with a continuous recorder.

(c) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under § 60.612 other than an incinerator, boiler, process heater, absorber, condensor or carbon adsorber shall provide to the Administrator information describing the operation of the control device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9))

§ 60.614 Test methods and procedures.

(a) The following test methods and procedures, except as provided under § 60.8(b), shall be used to determine compliance with the emission limit specified under § 60.612(a).

(1) Reference Method 1 or 1A, as appropriate, for selection of the sampling site. The control device inlet sampling site for determination of offgas molar composition or total organic compound reduction efficiency shall be prior to the inlet of any combustion device and after all product recovery units.

(2) Reference Method 2, 2A, 2C, or 2D as appropriate, for determination of the volumetric flowrate.

(3) Reference Method 3 for air dilution correction, based on 3 percent oxygen in the emission sample.

(4) Reference Method 18 and ASTM D2504-67 (reapproved 1977) to determine hourly emission rate of total organic compounds (minus methane and ethane) in the combustion device outlet and total organic compound reduction efficiency of the combustion device.

(5) Where a steam generating unit with a design heat unput capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with § 60.612(a), the requirement for an initial performance test is waived, in accordance with § 60.8(b). However, the Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(b) The following test methods and precedures, except as provided under § 60.8(b), shall be used for determining the process vent stream TRE index value to determine compliance under § 60.612(b).

(1) Reference Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flowrate and molar composition determination prescribed in § 60.614(b)(2) and (3) shall be prior to the inlet of any combustion device, prior to any post-reactor dilution of the stream with air, and prior to any post-reactor introduction of chlorinated compounds into the process vent stream. Subject to the preceding restrictions on the sampling site, it shall be after the final products recovery unit. If any gas stream other than the air oxidation process vent stream is normally conducted through the product recovery system of the affected facility, such stream shall be rerouted or turned off while the vent stream is sampled, but shall be routed normally prior to the measuring of the initial value of the parameter(s) to be monitored as specified in § 60.613(b). If the air oxidation process vent stream is normally routed through any equipment which is not a part of the affected facility as defined under § 60.610 and § 60.611, such equipment shall be bypassed by the process vent stream while the vent stream is sampled, but shall not be bypassed during the measurement of the initial value of the parameter(s) to be monitored as specified in § 60.613(b).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Reference Method 18 and ASTM D2504-67 (reapproved 1977) to measure VOC concentration, concentration of each compound containing chlorine, and concentration of all other compounds present except water vapor and carbon monoxide.

(ii) Reference Method 4 to measure the content of water vapor.

(iii) Reference Method 10 to measure carbon monoxide concentration. The process vent stream carbon monoxide concentration shall be calculated on a wet basis using the following equation:

$$C_{wco} = C_{co}(1 - B_w)$$

where:

C_{wco} = Concentration of carbon monoxide, wet basis, ppm.

C_{co} = Cencentration of carbon monoxide as determined using the recommended test method, ppm, dry.

B_w = Water vapor in the gas sample, proportion by volume.

(3) The volumetric flowrate shall be detemined using Reference Methods 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the process vent stream shall be calculated using the following equation:

$$H_T = K \left(\sum_{i=1}^{n} \right) C_i H_i + C_{wco} H_{co}$$

Where:

H_T = Net heating value of the sample, MJ/scm, where the net enthalpy per mole of offgas is based of combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C, as in the definition of Q_s (offgas flowrate).

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}} \right) \left(\frac{\text{g mole}}{\text{scm}} \right) \left(\frac{\text{MJ}}{\text{kcal}} \right),$$

where standard temperature for $\left(\frac{\text{g-mole}}{\text{scm}} \right)$ is 20°C.

C_i = Concentration of sample component i, ppm.

H_i = Net heat of combustion of sample component i, kcal/g-mole. The heats of combustion of process vent stream components would be required to be determined using ASTM D2382-76 if published values are not available or cannot be calculated.

C_{wco} = Concentration of carbon monoxide, wet basis, ppm.

H_{co} = Net heat of combustion of carbon monoxide, kcal/g-mole.

(5) The emission rate of total organic compounds (minus ethane and methane) in the process vent stream shall be calculated using the following equation:

$$E_{TOC} = K \left(\sum_{i=1}^{n} \right) C_i M_i \quad Q_s$$

where: emission rate of total organic compounds (minus methane and ethane) in the sample, kg/hr.

K = Constant, 2.494×10^{-6} (1/ppm)(g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20°C.

M_i = Molecular weight of sample component i, g/g-mole.

Q_s = Vent stream flowrate (scm/min), at a standard temperature of 20°C.

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Reference Method 18.

(7) The TRE index value of the process vent stream shall be calculated using the following equation:

$$TRE = \frac{1}{E_{TOC}} \left[a + b (Q_s)^{0.88} + c (Q_s) + d (Q_s)(H_T) + e (Q_s)^{0.78} (H_T)^{0.88} + f (H_T)^{0.88} \right]$$

where:

TRE = Total resource-effectiveness index value.

Q_s = Vent stream flowrate (scm/min), at a standard temperature of 20°C.

H_T = Vent stream net heating value (MJ/scm), as calculated in § 60.614(b)(4), where the net enthalpy of combustion per mole of offgas is based on combustion at 25°C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20°C, as in the definition of Q_s.

E_{TOC} = Hourly emissions of total organic compounds (minus methane and ethane) reported in kg/hr measured at full operating flowrate.

a,b,c,d,e, and f are coefficients.

The set of coefficients which apply to a process vent stream shall be obtained from Table 1.

(c) Each owner or operator of an affected facility shall recalculate the TRE index value for that affected facility whenever changes are made in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of product recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change to the product recovery system. In any instance where the recalculated TRE index value is less than 2.2, the owner or operator shall conduct a performance tests as required by § 60.614(a) in order to determine compliance with § 60.612(a).

TABLE 1. COEFFICIENTS OF THE TOTAL RESOURCE EFFECTIVENESS (TRE) INDEX EQUATION

A1. FOR CHLORINATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤3.3:

Q = Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q_s < 15$	46.21	0	0.763	-0.325	0	0
$15 < Q_s \leq 790$	38.98	0.754	0.763	-0.325	0	0
$790 < Q_s \leq 1590$	77.96	0.819	0.763	-0.325	0	0
$1590 < Q_s \leq 2380$	116.9	0.860	0.763	-0.325	0	0
$2380 < Q_s \leq 3160$	155.9	0.890	0.763	-0.325	0	0
$3160 < Q_s \leq 3960$	194.9	0.915	0.763	-0.325	0	0

A2. FOR CHLORINATED PROCESS VENT STREAMS, IF 3.3<NET HEATING VALUE (MJ/scm):

Q = Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q_s < 15$	46.21	0	-0.822	0	0	0
$15 < Q_s \leq 790$	38.98	0.754	-0.822	0	0	0
$790 < Q_s \leq 1590$	77.96	0.819	-0.822	0	0	0
$1590 < Q_s \leq 2380$	116.9	0.860	-0.822	0	0	0
$2380 < Q_s \leq 3160$	155.9	0.890	-0.822	0	0	0
$3160 < Q_s \leq 3960$	194.9	0.915	-0.822	0	0	0

B. FOR NONCHLORINATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm) ≤0.45:

Q = Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q_s < 15$	18.03	0	0.257	-0.426	0	0
$15 < Q_s \leq 1520$	15.83	0.229	0.257	-0.426	0	0
$1520 < Q_s \leq 3050$	31.66	0.248	0.257	-0.426	0	0
$3050 < Q_s \leq 4570$	47.49	0.262	0.257	-0.426	0	0

C. FOR NONCHLORINATED PROCESS VENT STREAMS, IF 0.45<NET HEATING VALUE (MJ/scm)≤1.8:

Q = Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q_s < 15$	18.05	0	0.912	-0.403	0	0
$15 < Q_s \leq 1520$	16.86	0.123	0.912	-0.403	0	0
$1520 < Q_s \leq 3050$	33.72	0.134	0.912	-0.403	0	0
$3050 < Q_s \leq 4570$	50.58	0.279	0.912	-0.403	0	0

D. FOR NONCHLORINATED PROCESS VENT STREAMS, IF 1.8 < NET HEATING VALUE (MJ/scm)≤3.4:

Q Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q_s < 15$	14.31	0	0.073	0	0	0
$15 < Q_s \leq 1340$	12.83	0.154	0.073	0	0	0
$1340 < Q_s \leq 2680$	25.66	0.167	0.073	0	0	0
$2680 < Q_s \leq 4020$	38.49	0.176	0.073	0	0	0

E. FOR NONCHLORINATED PROCESS VENT STREAMS, IF 3.4<NET HEATING VALUE (MJ/scm):

Q = Standard Flowrate (scm/min)	a	b	c	d	e	f
$Q < 15$	14.31	0	0	0.0019	0	0.450
$15 < Q_s \leq 1340$	12.83	0	0	0.0019	0.047	0
$1340 < Q_s \leq 2680$	25.66	0	0	0.0019	0.051	0
$2680 < Q_s \leq 4020$	38.49	0	0	0.0019	0.054	0

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(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9))

§ 60.615 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.612 shall notify the Administrator of the specific provisions of § 60.612 [§ 60.612 (a) or (b)] with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of § 60.612 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by § 60.614.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily-accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under § 60.8, except when a steam generating unit with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with § 60.612(a), in which case an initial report containing the data specified in (b)(2) of this section shall be submitted at the startup of the facility. The same data specified in paragraph (b) (1) or (3) of this section, as appropriate, shall be submitted in the reports of all subsequently required performance tests where either the total organic compound emission control efficiency of a combustion device or the TRE index value of a process vent stream from a product recovery system is determined.

(1) Where an owner or operator subject to this subpart seeks to demonstrate compliance with § 60.612(a) through use of a combustion device (except for a steam generating unit with a design heat input capacity of 44 MW or greater):

(i) The average firebox temperature of the thermal oxidizer or steam generation unit with a design heat input capacity of less than 44 MW (or the average temperature upstream and downstream of the catalyst bed), every 15 minutes and averaged over a 3-hour period, and

(ii) The percent reduction of total organic compounds (minus methane and ethane) achieved by the combustion device, or the concentration (ppmv, by compound) of total organic compounds (less methane and ethane) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to this subpart seeks to demonstrate compliance with § 60.612(a) through use of a steam generating unit with a design heat input capacity of 44 MW or greater, the initial report will contain a statement of the design heat input capacity of the steam generating unit to be used.

(3) Where an owner or operator seeks to demonstrate compliance with § 60.612(b):

(i) The specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average temperature, measured every 15 minutes and averaged over a 3-hour period, of the absorbing liquid (both measured while the vent stream is normally routed and constituted), where an absorber is the final unit in a system, or

(ii) The average exit (product side) temperature, measured every 15 minutes and averaged over a 3-hour period while the vent stream is normally routed and constituted, where a condenser is the final unit in a system, or

(iii) The manifold steam pressure measured every 15 minutes and averaged over the period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration [and within 15 minutes of completion of any cooling cycle(s)], and duration of the carbon bed steaming cycle where a carbon adsorber is the final unit in a system (all measured while the vent stream is normally routed and constituted), and

(iv) All measurements and calculations performed to determine the TRE index value of the process vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily-accessible continuous records of the equipment operating parameters specified to be monitored under § 60.613(a), as well as up-to-date, readily-accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report ot these data. Where a combustion device is used by an owner or operator seeking to demonstrate compliance with § 60.612(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incineration or combustion in a steam generating unit with a design heat input capacity of less than 44 MW (150 million Btu/hour), all 3-hour periods of operation during which the average combustion the, temperature was more than 28°C (50°F) below the average combustion temperature during the most recent performance test at which compliance with § 60.612(a) was determined.

(2) For catalytic incineration, all 3-hour periods of operation during which the average temperature of the device immediately before the catalyst bed is more than 28°C (50°F) below the average temperature of the device during the most recent performance test at which compliance with § 60.612(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the device during the most recent performance test at which compliance with § 60.612(a) was determined.

(d) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily-accessible continuous records of the equipment operating parameters specified to be monitored under § 60.613(b) as well as up-to-date, readily-accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where the owner or operator seeks to demonstrate compliance with § 60.612(b), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final unit in a system,

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11°C (20°F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he or she will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final unit in a system, all 3-hour periods of operation during which the average

condenser operating temperature was more than 6°C (10°F) above the average operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final unit in a system,

(i) All carbon bed regeneration cycles during which the total mass steam flow was below the total mass steam flow pressure during the most recent performance test, and

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration [and after completion of any cooling cycle(s)] was more than 10 percent greater than the carbon bed temperature (in degrees centigrade) during the most recent performance test.

(4) Where a carbon adsorber is the final unit in the recovery system and a total organic compound monitor approved by the Administrator is used, all 3-hour periods of operation during which the average concentration of total organic compounds (less methane and ethane) in the carbon adsorber gases is more than 50 parts per million by volume and more than 20 percent greater than the exhaust gas concentration measured by the monitoring system during the most recent performance test.

(e) Each owner or operator subject to the provisons of this subpart who uses a steam generating unit with a design heat input capacity of 44 MW (150 million Btu/hour) or greater and seeking to demonstrate compliance with § 60.612(a) shall keep an up-to-date, readily accessible record of all periods of operation of the steam generating unit. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) Each owner or operator subject to the provisions of this subpart and seeking to demonstrate compliance with § 60.612(b) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of product recovery equipment;

(2) Any recalculation of the TRE index value performed pursuant to § 60.614(c);

(3) The results of any performance test performed pursuant to § 60.614(c).

(g) Each owner and operator subject to the provisions of this subpart is exempt from § 60.7(c) of the General Provisions.

(h) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of § 60.612 shall submit to the Administrator semi-annual reports of the information recorded under §§ 60.615 (c), (d), and (f). In addition, when a steam generating unit with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with § 60.612(a), the owner or operator of the affected facility shall submit to the Administrator semi-annual reports of all periods during which the steam generating unit is not operating, as recorded under § 60.615(e). The initial report shall be submitted within 6 months after the initial start-up date.

(i) The requirements of § 60.615(h) remain in force until and unless EPA, in delegating enforcement authority to a State under Section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with § 60.615(h), provided that they comply with the requirements established by the State.

(j) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility seeks to demonstrate compliance with the standards specified under § 60.612 other than as provided under § 60.613 (a) and (b).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9))

§ 60.615 Reconstruction.

(a) For purposes of this subpart "fixed capital cost of the new components", as used in § 60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following (date of proposal). For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

It is proposed that Appendix A of 40 CFR Part 60 be amended as follows:

2. Reference Method 1A is added to Appendix A as follows:

Appendix A—Reference Methods

* * * * *

Method 1A—Sample and Velocity Traverses for Stationary Sources with Small Stacks or Ducts

1. *Applicability and Principle*

The applicability and principle of this method are identical to Method 1, except its applicability is limited to stacks or ducts less than about 0.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) in cross-sectional area, but equal to or greater than about 0.10 meter (4 in.) in diameter, or 0.0081 m^2 (12.57 $in.^2$) in cross-sectional area.

In these small diameter stacks or ducts the conventional pitot assembly (consisting of a Type S pitot tube attached to a sampling probe, equipped with a nozzle and thermocouple) blocks a significant cross-section of the duct and prevents a true traverse. Therefore, for particulate sampling in small stacks or ducts, the gas velocity is measured using a standard pitot tube downstream of the actual emission testing site. The straight run of duct between the sampling and velocity measurement sites allows the flow profile, temporarily disturbed by the presence of the sampling probe, to redevelop and stabilize.

The cross-sectional layout and location of traverse points and the verification of the absence of cyclonic flow are the same as in Method 1, Sections 2.3 and 2.4, respectively. Differences from Method 1, except as noted, are given below.

2. *Procedure*

2.1 Selection of Measurement Site.

2.1.1 Particulate Measurements—Steady or Unsteady Flow. Select a particulate measurement site located preferably at least eight equivalent stack or duct diameters downstream and 10 equivalent diameters upstream from any flow disturbances such as a bends, expansions, or contractions in the stack, or from a visible flame. Next, locate the velocity measurement site eight equivalent diameters downstream of the particulate measurement site. See Figure 1A-1. If such locations are not available, select an alternative particulate measurement location at least two equivalent stack or duct diameters downstream and two and one-half diameters upstream from any flow disturbance. Then, locate the velocity measurement site two equivalent diameters downstream from the particulate measurement site. (See Section 2.1 of Method 1 for calculating equivalent diameters for a rectangular cross-section.)

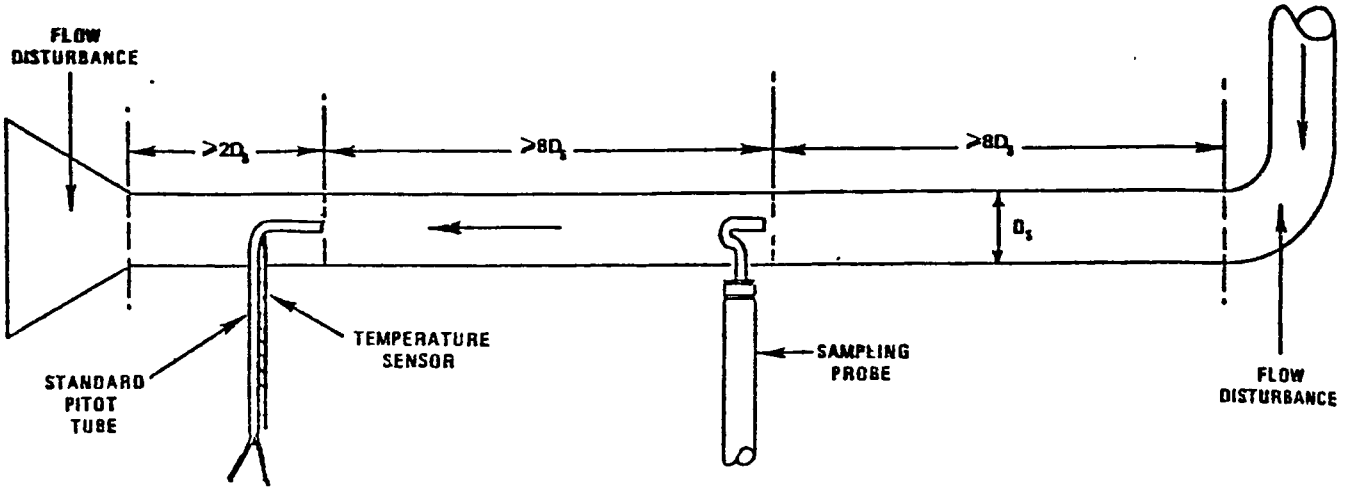

Figure 1A-1. Recommended sampling arrangement for small ducts.

2.1.2 Particulate (Steady Flow) or Velocity (Steady or Unsteady Flow) Measurements. If the average total volumetric flow rate in a duct is constant with respect to time or if only velocity measurements are required use the same criterion as in Section 2.1 of Method 1.

2.2 Determining the Number of Traverse Points.

2.2.1 Particulate Measurements (Steady or Unsteady Flow). Use Figure 1-1 of Method 1 to determine the number of traverse points. Before referring to the figure, however, determine the distance between the velocity and sampling sites and the distances to the nearest upstream and downstream disturbances and divide each distance by the stack diameter or equivalent diameter to determine the distances in terms of the number of duct diameters. Then, determine the number of traverse points from Figure 1-1 of Method 1 corresponding to each of these three distances. Choose the highest of the three numbers of traverse points (or a greater number) so that for circular ducts the number is a multiple of four; for rectangular ducts use one of those numbers shown in Table 1.1 of Method 1.

2.2.2 Particulate (Steady Flow) and Velocity (Non-Particulate) Measurements. Use Figure 1A-3 to determine number of traverse points, following the same procedure used for particulate traverses as described in Section 2.2.1 of Method 1.

3. *Bibliography*

1. Same as Method 1, Section 3, Citations 1 through 6.

2. Vollaro, Robert F. Recommended Procedure for Sample Traverses in Ducts Smaller Than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, North Carolina. January 1977.

3. Reference Method 2C is added to Appendix A as follows:

Appendix A—Reference Methods

* * * * *

Method 2C—Determination of Stack Gas Velocity and Volumetric Flow Rate From Small Stacks or Ducts (Standard Pitot Tube)

1. *Aplicability and Principle*

1.1 Applicability. The applicability of this method is identical to Method 2, except it is limited to stationary source stacks or ducts less than about 0.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) in cross-sectional area, but equal to or greater than about 0.10 meter (4 in.) in diameter or 0.0081 m^2 (12.57 $in.^2$) in cross-sectional area.

The apparatus, procedure, calibration, calculations, and bibliography are the same as in Method 2, Sections 2, 3, 4, 5, and 6, except as noted in the following sections.

1.2 Principle. The average gas velocity in a stack or duct is determined from the gas density and from measurement of velocity heads with a standard pitot tube.

2. *Apparatus*

2.1 Standard Pitot Tube (instead of Type S). A standard pitot tube which meets the specifications of Section 2.7 of Method 2. Use a coefficient of 0.99 unless it is calibrated against another standard pitot tube with an NBS-traceable coefficient.

2.2 Alternative Pitot Tube. A modified hemispherical-nosed pitot tube (see Figure 2C-1), which features a shortened stem and enlarged impact and static pressure holes. Use a coefficient of 0.99 unless it is calibrated as mentioned in Section 2.1 above. This pitot tube is useful in particulate liquid droplet laden gas streams when a "back purge" is ineffective.

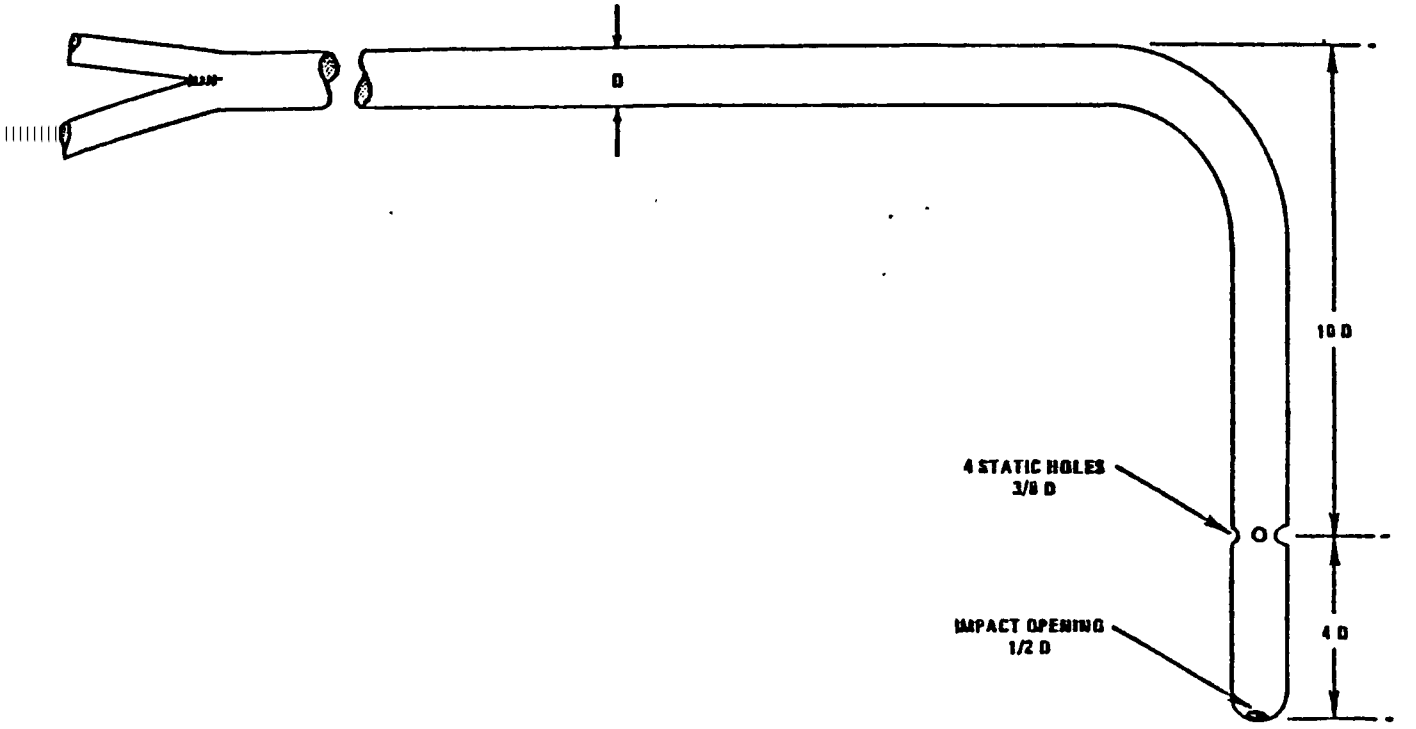

Figure 2C-1. Modified hemispherical-nosed pitot tube.

3. *Procedure*

Follow the general procedures in Section 3 of Method 2, except conduct the measurements at thetraverse points specified in Method 1A. The static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, the tester must furnish adequate proof that the openings of the pitot tube have not plugged during the traverse period; this can be done by taking the velocity head (Δp) heading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another Δp reading. If the Δ readings made before and after the air purge are the same (± 5 percent) the traverse is acceptable. Otherwise, reject the run. Note that if the ΔP at the final traverse point is unsuitably low, another point may be selected. If "back purging" at regular intervals is part of the procedure, then take comparative Δp readings, as above, for the last two back purges at which suitably high Δp readings are observed.

4. Reference Method 2D is added to Appendix A as follows:

Appendix A—Reference Methods

* * * * *

Method 2D—Measurement of Gas Volume Flow Rates in Small Pipes and Ducts

1. *Applicability and Principle*

1.1 Applicability. This method applies to the measurement of gas flow rates in small pipes and ducts. It can only be applied to intermittent or variable gas flows with particular caution.

1.2 Principle. All the gas flow in the pipe or duct is directed through a rotameter, orifice plate or similar device to measure flow rate or pressure drop. The device has been previously calibrated in a manner that insures its proper calibration for the gas being measured. Absolute temperature and pressure measurements are made to adjust volume flow rates to standard conditions.

2. *Apparatus.*

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

2.1 Gas Metering Rate or Flow Element Device. A rotameter, orifice plate, or other volume rate or pressure drop measuring device capable of measuring the stack flow rate to within 5 percent. The metering device shall be equipped with a temperature gauge accurate to within 2 percent of the minimum absolute stack temperature and a pressure gauge (accurate to within 5 mm Hg). The capacity of the metering device shall be sufficient for the expected maximum and minimum flow rates at the stack gas conditions. The magnitude and variability of stack gas flow rate, molecular weight, temperature, pressure, dewpoint, and corrosive characteristics, and pipe or duct size are factors to consider in choosing a suitable metering device.

2.2 Barometer. Same as Method 2, Section 2.5.

2.3 Stopwatch. Capable of measurement to within 1 second.

3. *Procedure*

3.1 Installation. Use the procedure in Method 2A, Section 3.1.

3.2 Leak Check. Use the procedure in Method 2A, Section 3.2.

3.3 Volume Rate Measurement.

3.3.1 Continuous, Steady Flow. At least once an hour, record the metering device flow rate or pressure drop reading, and the metering device temperature and pressure Make a minimum of 12 equally spaced readings of each parameter during the test period. Record the barometric pressure at the

beginning and end of the test period. Record the data on a table similar to Figure 2D–1.

3.3.2 Noncontinuous and Nonsteady Flow. Use volume rate devices with particular caution. Calibration will be affected by variation in stack gas temperature, pressure and molecular weight. Use the procedure in Section 3.3.1 with the addition of the following: Record all the metering device parameters on a time interval frequency sufficient to adequately profile each process cyclical or noncontinuous event. A multichannel continous recorder may be used.

Plant _____
Flow meter location _____
Calibration date _____ Calibration run number _____
Operators _____
Metering device type _____
Metering device number _____
Calibration coefficient _____
Calibration gas _____ Date to recalibrate _____
Barometric pressure (mm Hg) Start _____ Finish _____

Time run/clock	Volume rate or pressure drop reading	Static pressure (mm Hg)	Temperature	
			°C	°K
Average				

Figure 2D–1. Volume flow rate measurement data.

4. *Calibration*

4.1 Gas Metering Device. Use the procedure in Method 2A, Section 4, and apply the same performance standards. Calibrate the metering device with the principle stack gas to be measured (examples: air, nitrogen) against a standard reference meter. A calibrated dry gas meter is an acceptable reference meter. Ideally, calibrate the metering device in the field with the actual gas to be metered. For metering devices that have a volume rate readout, calculate the test metering device calibration coefficient, Y_m, for each run as follows:

$$Y_m = \frac{(V_r)(T_r)}{(V_m)(T_m)} \frac{P_{bar}}{(P_{bar}+P_g)} \quad \text{Eq. 2D–1}$$

Where:

V_r = Reference meter volume rate reading, m^3/min.
V_m = Test meter volume rate reading, m^3/min.
T_r = Absolute reference meter average temperature, °K.
T_m = Absolute test meter average temperature, °K.
P_{bar} = Barometric pressure, mm Hg.
P_g = Test meter average static pressure, mm Hg.

For metering devices that do not have a volume rate readout, refer to the manufacturer's instructions to calculate the V_m corresponding to each V_r.

4.2 Temperature Gauge. Use the procedure and specifications in Method 2A, Section 4.2. Perform the calibration at a temperature that approximates field test conditions.

4.3 Barometer. Calibrate the barometer to be used in the field test with a mercury barometer prior to the field test.

5. *Gas Flow Rate Calculation*

Use the equations in Method 2A, Section 5, except time is already factored in.

6. *Bibliography*

1. United States Environmental Protection Agency. Standards of Performance for New Stationary Sources, Revisions to Methods 1–8. Title 40, Part 60. Washington, D.C. Federal Register Vol. 42, No. 160. August 18, 1977.

2. United States Environmental Protection Agency. Standards of Performance for New Stationary Sources. Proposed Method 2A. Title 40, Part 60. Washington, D.C. Federal Register Vol. 45, No. 244. December 17, 1980.

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16. ABSTRACT

The Regulatory Documents Handbook is to be used for the Air Pollution Training Institute Course 482 "Sources and Control of Volatile Organic Air Pollutants." This publication contains selected Federal Register Notices, Federal Register SIP notices, EPA policy statements, and proposed and final New Source Performance Standards for new sources of volatile organic compounds.

This publication is intended for use in conjunction with the Student Workbook (EPA 450/2-81-011) and the Instructor's Guide (EPA 450/2-81-010) for APTI Course 482.

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