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WHITE HOUSE
CORRESPONDENCE TRACKING WORKSHEET

Acid Rain

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☐ O - OUTGOING
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Name of Correspondent: JOHN HENRY

☐ **MI Mail Report** **User Codes: (A)** _____ **(B)** _____ **(C)** _____

Subject: Forwards copy of letter from Mario Cuomo to Administrator Reilly, re: SO_2 allowance system

ROUTE TO:		ACTION		DISPOSITION		
Office/Agency	(Staff Name)	Action Code	Tracking Date YY/MM/DD	Type of Response	Code	Completion Date YY/MM/DD
CUOFC		ORIGINATOR	91/11/22		C	91/11/25
CUAT		Referral Note:	Attn: FY			
17		I	91/11/25	DJ	C	91/11/25
		Referral Note:		See Comments		
CUGray		I	/ /			/ /
		Referral Note:				
			/ /			/ /
		Referral Note:				
			/ /			/ /
		Referral Note:				

ACTION CODES:
A - Appropriate Action
C - Comment/Recommendation
D - Draft Response
F - Furnish Fact Sheet to be used as Enclosure
I - Info Copy Only/No Action Necessary
R - Direct Reply w/Copy
S - For Signature
X - Interim Reply

DISPOSITION CODES:
A - Answered
B - Non-Special Referral
C - Completed
S - Suspended

FOR OUTGOING CORRESPONDENCE:
Type of Response = Initials of Signer
Code = "A"
Completion Date = Date of Outgoing

Comments: NO action required. JRH/KRM 11/25/91

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FAX COVER SHEET

To: C.B. Gray

Company : White House

Fax Number : 456-6279

From : John B. Henry

Company : CACM

Fax Number : (202) 466-2888

If you have any problem sending a fax please call (202) 466-0500

Date :

Message : In case you missed this, Mario Cuomo is threatening to undermine the SO_2 allowance system President Bush and you created. This position is preventing New York utilities from selling their allowances.

ENCLOSURE 9 FM

STATE OF NEW YORK
EXECUTIVE CHAMBER
ALBANY 12224

MARIO M. CUOMO
GOVERNOR

August 29, 1991

Dear Administrater Reilly:

New York and the other Northeast states campaigned for years in support of a strong national program of acid rain controls. As the region most adversely affected by the long range transport and subsequent deposition of acid compounds, we applauded last November when the Clean Air Act Amendments of 1990 was enacted mandating for the first time a national acid deposition control program.

New York had long advocated a minimum ten million ton reduction program. We were therefore pleased when the Clean Air Act Amendments adopted a two-phase program of control designed to achieve a ten million ton reduction in the emissions of sulfur dioxide from a 1988 base. The ten million ton reduction was supported analytically by evidence that showed it would result in approximately a 50% percent reduction in acid deposition at sensitive receptors throughout the Northeast. That is the objective, and it is a good one.

With that objective in mind, I write to express my concern over implementation of the acid rain provisions, specifically the allowance trading program. The Clean Air Act Amendments adopted some new provisions that, in theory, are designed to achieve the most cost-effective application of controls to meet the acid rain reduction targets. The allowance program purports to allow those utilities which reduce emissions below the required levels to sell their "excess" emission reductions to other utilities which have not met required reduction levels.

We support this type of innovation. However, we must be vigilant in assuring that implementation of this program does not undermine the Act's goal. Unless those means are directed to the end of reducing adverse environmental impacts, we will not have produced the environmental benefit of deposition reduction in the Northeast that was clearly contemplated by the Congress.

More specifically, we are concerned that if the allowance trading program is not governed by regulations connecting the emission reduction program to deposition reductions, the Clean Air Act's promise will not be met. That would be a tragic irony.

Unless the trading policy connects the deposition reduction targets to the emission reduction program in the allowance trading program, the dynamics of energy and economic policy could produce emission reductions in a way that does not materially contribute to deposition reduction at sensitive areas in New York and the Northeast.

For example, it is conceivable that enough power plants in the Gulf Coast region and even in the Northeastern states could switch to natural gas and sell their emission reduction credits to large, tall stack heavy sulfuric oxide coal emitters in the Ohio Valley. By purchasing these credits, these plants could avoid application of emission controls, thus severely reducing potential environmental benefits in the Northeast.

Since these plants are the source of most of the acid compounds deposited in the Northeast, an undisciplined trading program could result in continuing deterioration of our sensitive lakes and forests --- the very lands which Congress intended to protect.

I'm sure you appreciate the seriousness of our concern. Without disciplinary guidance from EPA, the trading program could result in inadequate environmental protection for vulnerable water bodies and woodlands, especially in New York and the Northeast.

I respectfully request that EPA develop regulations which provide for some connection between emission reductions and deposition results. Otherwise, I suggest, the great promise of the Act could be frustrated.

New York is prepared to work with you in developing the necessary regulations to implement the Clean Air Act so as to achieve the Act's intended environmental benefits with cost effective programs.

Sincerely,

Mario M. Cuomo

Mr. William K. Reilly
Administrator
U.S. Environmental Protection Agency
401 M Street, S.W.
Room 1200, West Tower
Washington, D.C. 20460

cc: Hon. Thomas C. Jorling, Commissioner
NYS Dep. of Environmental Conservation
Drew Zar M.A. Crotty Frank Murray Joe Marrens Files

would apply to the Acid Rain Program. Today's proposal specifies that, within the 40 CFR Part 70 structure, the Acid Rain Program would apply permit modification procedures to changes such as the addition of a new compliance option that involves a unit at a source not previously subject to the Acid Rain permit's requirements. In addition, sections 72.300(e) and 72.301 provide that a State decision interpreting an Acid Rain Program permit provision in a manner that effectively modifies or voids a Program requirement would be deemed a proposed permit modification by operation of law.

As with any proposed permit modification by the State during Phase II, such an interpretation would be subject to Agency review pursuant to section 70.8 of the Title V rules. Under 40 CFR Part 70 public comment and Federal oversight, as required for original permit issuance, would be required for modifications except that such comment and oversight would cover only the proposed permit changes, rather than the unchanged activities at a source.

Fast-Track Modifications. The Agency believes that an expedited permit modification procedure is necessary to provide sources with the flexibility to make needed changes in a timely manner. The proposal, therefore, includes a separate procedure, or "fast-track modification", which would be used, for example, (1) where an affected source wishes to change its method of compliance with the Acid Rain Program requirements to an Acid Rain compliance option under Subpart D which it did not submit for approval and comment during the permit issuance or reissuance process; (2) for a compliance option termination that was not contemplated by the permit; or (3) for a change in an approved compliance option which is significant enough to consider it as a new option (e.g. adding a unit to a multi-unit plan). The Acid Rain compliance option is a fundamental component of the permit. Changes in the compliance option have significant implications for allowance allocations, on emissions levels, and sometimes, on unit coverage under the Program.

Thus, the Agency believes that significant changes to compliance options must not occur without adequate opportunity for public involvement. This approach is consistent with the NPDES, RCRA, and UIC programs, all of which mandate an opportunity for public comment before incorporating any significant changes into the operating permit. The time and resources involved in the permit modification process set forth in 40 CFR Part 70 would, however, take away much of the source flexibility which the Acid Rain Program was designed to ensure. Congress intended the Acid Rain Program to promote least-cost planning through optional methods of compliance and an active allowance market. Requiring the affected source to go through a time- and resource-intensive process each time it wished to change its method of compliance would restrict much of the

flexibility of the Acid Rain Program. Sources should be able to revise their methods of compliance where the method originally chosen does not turn out to be cost-effective.

Balanced against this interest is the need to have public involvement in major permitting decisions, and the need to ensure that the source is held accountable for the requirements in its permit. The Agency is, therefore, proposing a fast-track modification procedure to avoid the excessive delays associated with the permit modification procedure proposed in 40 CFR Part 70, while not sacrificing the need for public notice and comment on a substantial change to the permit. The proposal includes two options for the fast-track modification procedure. The Agency requests comment on both.

In most cases a prudent source, uncertain of the most cost-effective method of compliance, will include several compliance options in its permit application and compliance plan, with a schedule by which it will decide which method(s) it will use. The Agency encourages sources to do this. In this way, when the source notifies EPA of the method it wishes to use, or that it wishes to switch methods, the permit could be revised through the administrative amendment procedure. (See, section 70.7(e) and discussion below.) The Agency believes this approach is appropriate because the compliance option will have undergone public notice and comment during the permit issuance procedure.

Sources may not always be able to predict all possible methods of compliance that they might need during the permit issuance process. A source may wish to change its method of compliance in the middle of the permit term.

The Agency believes that sources should not, however, be allowed to change in the middle of the permit term to a compliance option that was not previously reviewed, without some opportunity for public comment. To do so would undermine the benefits derived from the public notice and comment provisions in the permit issuance and reissuance process. If changes were allowed without notice and comment, a source could initially propose a compliance plan which it knew would meet with public acceptance, wait until the permit was issued, then submit a compliance plan more to its liking which would go into effect without an opportunity for public review. While the Agency believes that this would rarely happen intentionally, the proposed regulations would guard against such "gaming" of the permit process. In addition, while compliance plan changes probably would be submitted in good faith, the public has an interest in, and a right to know and comment on, what sources plan to do to comply with Acid Rain requirements. This subpart therefore proposes a "fast-track modification" process which includes expeditious notification to interested members of the public, yet avoids some of the delays necessitated by the permit modification process proposed in 40 CFR Part 70.

Three approaches to fast-track modifications are offered. Under the first approach, the applicant would submit the proposed revision to EPA. The Agency would then have 30 days to approve or disapprove it. If the Agency proposed to approve the revision, actual notice would be sent to interested persons, i.e. all persons who (1) commented on the proposed permit, or (2) requested during the public comment period to be informed of any subsequent permit actions proposed to be taken concerning the source. (The second category of interested persons could get their names on a mailing list for notice of any subsequent permit actions, whether or not they had comments on the initial proposed permit.) Interested persons would have 15 days in which to raise substantive objections to the proposed fast-track modification. If no substantive objections were received, the modification would take effect. If substantive objections were received, the proposal would have to go through the permit modification procedure, including general public notice, of 40 CFR Part 70. Objections would be evaluated by the permitting authority, using the criteria in section 72.77, to determine whether they were substantive.

Under the second approach to the fast-track modifications, the permittee would give public notice of its proposed new compliance option through publication in a journal (or newspaper) of national and general circulation. The permittee would also give actual notice to each interested person. The public would have 30 days to comment, after which the permittee would submit the proposed fast-track modification and all public comments received to the Agency. The Agency would approve or disapprove the fast-track modification within 30 days of receipt.

The Agency believes that either of these approaches would prove to be more expeditious than the permit modification procedures of 40 CFR Part 70, without sacrificing the need for public notice and comment. The first approach is more streamlined than the second, so long as no substantive objections are raised. The second approach would be quicker if the public were to raise objections. In its final rulemaking, the Agency could: (1) promulgate the permit modification procedure of 40 CFR Part 70 only for new compliance options, (2) choose one of the options for fast-track modifications, or (3) promulgate both fast-track modification options into regulation and allow the permittee discretion to choose which option to use. The Agency requests comment on these approaches.

Administrative Permit Amendments. The Agency also proposes to adopt, for purposes of the Acid Rain Program, the administrative amendment procedures set forth at 40 CFR Part 70. An administrative permit amendment under 40 CFR Part 70 would be made by the permitting authority, with no advance public notice or comment required. Changes to a permit, such as corrections of typographical errors, changes in names, addresses, and phone numbers, a change which requires more frequent monitoring at a source, and in most cases a change in ownership or operational control at a source are included under the administrative amendments procedures of 40 CFR Part 70. Today's proposal would include changes such as the granting of an alternative emissions limitation for NO_x where such limitation is the same as that previously approved for the demonstration period plan under section 72.47; the activation of a compliance option which was conditionally approved in the original permit application provided that the option is activated within the time frame specified in the permit; and changes to the designated representative so long as a new certificate of representation has been submitted. In addition, the administrative amendments procedures would apply to alternative monitoring systems approved under 40 CFR Part 75 of today's proposal, and excess emissions offset plans pursuant to section 411 of the Act approved by the Administrator according to procedures specified in 40 CFR Part 77 of today's proposal. The procedures for these two categories of actions by the Administrator include public comment. Further public comment would, therefore, be redundant.

Minor Permit Amendments. Under 40 CFR Part 70 a minor permit amendment procedure is also authorized, to cover any proposed revision to a permit that is not a modification under Title I.[10] This procedure is primarily intended to provide sources with operating flexibility in their day-to-day operations. Because the Acid Rain Program is an annual program which, by definition, provides ample flexibility with regard to variation in operating conditions throughout the year, the Agency

[10] The source would be required to notify the permitting authority 7 calendar days before the change is to occur. The rule would require the change to comply with all applicable elements of the Act relevant to the source. Under this procedure, the permitting authority has 7 days to notify the source if the change is not acceptable as a minor amendment, and it is then treated as a modification.

does not believe that this procedure would be necessary or applicable to the types of revisions that will be seen in Acid Rain Program. In addition, since State procedures for minor permit amendments may vary, this form of revision could undermine the overriding goal of the Acid Rain Program of national consistency. Thus, it is important that all States follow the same procedures for Acid Rain permit revisions to ensure this consistency. The Agency wishes to avoid situations where a change to an Acid Rain permit is treated as a minor permit amendment in one State, but not another. The Acid Rain Program needs to ensure that sources are not penalized or benefitted based on the State in which they are located. Since States can develop their own procedures, the resource burden associated with minor permit amendments may vary from State to State. Thus, the Agency is proposing that no revisions to the Acid Rain portion of a permit would be processed under the minor permit amendment procedure.

Automatic Permit Amendments. The proposal also provides that properly registered allowance transactions would automatically amend the permit. Title IV of the Act specifies that allowance transactions be treated differently from most permit revisions. The proposal reflects this statutory requirement. Allowance transactions are incorporated into permits as automatic amendments upon recordation by the Administrator. A detailed discussion of allowance transaction recordation can be found in the 40 CFR Part 73 preamble.

Subpart K - Compliance Certification

Compliance certifications are a fundamental element of the Acid Rain Program's implementation strategy. The statutory authority for this strategy can be found in section 114(a) of the Act (as amended by section 702 of Act Amendments of 1990), which requires that the Administrator promulgate compliance certification regulations, and in section 504(c) in Title V of the Act, which requires that compliance certification requirements be included in each source's operating permit.

The Agency believes that heavy reliance on compliance certifications in the Acid Rain Program will greatly reduce the burden on sources of demonstrating compliance while maintaining the Agency's ability to ensure program accountability. They will also provide a helpful vehicle for resolving misunderstandings concerning applicable requirements before there has been a violation, which should greatly increase Program certainty for sources.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
GENERAL COUNSEL

MEMORANDUM

SUBJECT: Draft General Counsel Opinions - - Acid Rain Issues
(1) Applicability of Phase I NOx Requirements to Compensating Units (Reduced Utilization)
(2) Definition of Repowering

FROM: Alan W. Eckert
Associate General Counsel
Air and Radiation Division, LE-132A

TO: See Below

Attached are copies, in draft form, of EPA General Counsel legal opinions regarding the two acid rain issues noted above. In accordance with our standard procedure, we would be pleased to consider any comments you might have before issuing these opinions in final form. As you know, a policy closure meeting on the acid rain proposed rulemaking package is scheduled for September 12. In order to keep to this schedule, we request that you provide any comments you may have by September 6.

Attachments

cc: Gerald Yamada, LE-130
Bill Rosenberg, ANR-443
Eileen Claussen, ANR-445

Addressees:
Jeff Holmstead, Associate Counsel to the President
Barry Hartman, Acting Assistant Attorney General, Dept. of Justice
David Rivkin, Associate General Counsel, Dept. of Energy
Art Fraas, Office of Management and Budget

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

Draft: August 30, 1991

OFFICE OF
GENERAL COUNSEL

MEMORANDUM

SUBJECT: Definition of "Repowering" as used in Title IV of the Clean Air Act as amended November 15, 1990

FROM: Gerald H. Yamada
Principal Deputy General Counsel, LE-130

TO: William G. Rosenberg
Assistant Administrator
for Air and Radiation, ANR-443

Section 409 of the Clean Air Act (CAA) authorizes the permitting authority to grant four year extensions of the Phase II compliance deadline to units that will be "repowered" with a qualifying clean coal technology. Section 402(12) of the statute defines "repowering" as follows:

> replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990. * * *[1]

In order to qualify for a four year Phase II compliance extension a unit must fall within the definition of repowering contained in section 402(12) of the statute. EPA's draft acid rain permits rule directly tracks the legislative language cited above. Specifically, the preamble language provides that in

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[1] Clean Air Act, Section 402(12), 42 U.S.C. 7651a.

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order to qualify for the extension, an affected unit must undergo replacement or substantial modification of the boiler.

QUESTION

Does the repowering definition used in Title IV require boiler replacement or substantial modification to qualify for a section 409 repowering extension?

ANSWER

The plain statutory language of Title IV clearly requires replacement or substantial modification of a boiler to qualify for a section 409 repowering extension. Furthermore, this interpretation of the statutory language is supported by the legislative history, statutory scheme, and overall legislative intent.

DISCUSSION

By way of background, it is useful first to discuss the legislative purpose of Title IV of the Clean Air Act in general, and, more specifically, the context in which the repowering extension issue arises.

The primary purpose of Title IV "is to reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide . . . " Section 401(b). Congress was equally clear that it "is the intent of this title to effectuate such reductions by requiring compliance by affected sources with prescribed emission limitations by specified deadlines . . . " Id. Compliance may be achieved either directly or through trading of sulfur dioxide allowances. Id. Congress provided a number of limited emission reduction deadline extensions in pursuit of various secondary goals of Title IV, which are also spelled out in the Purposes section of the title. See Id. Of relevance here is the Phase II emissions reduction deadline extension in section 409 for sources that undertake boiler replacement with qualifying clean coal technologies. This provision comports with the secondary statutory purpose "to encourage . . . clean alternative technologies." Section 401(b).

The section 409 extension provision is one of several provisions in Title IV intended to accommodate Clean Coal Technologies. See, e.g., section 409(d), section 409(e), section 415(b), providing regulatory incentives and exemptions for Clean Coal Technology projects under new source requirements of Title I of the Act. All of these provisions must be read in light of the explicit congressional directive that they be carried out

"consistent with the provisions of this title." See section 401(b). In the context of Title IV, this directive instructs EPA to implement the section 409 repowering extension in a manner consistent with the overall statutory purpose of reducing sulfur dioxide emissions to the levels specified in the Title. Of course, EPA must also be mindful of the central tenet of statutory construction that exceptions from regulatory statutes be read narrowly and in keeping with the legislative intent of the program in question.

Turning to the statutory terms themselves, the first question EPA must address is

> whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the . . . agency must give effect to the unambiguously expressed intent of Congress.

Chevron, U.S.A., Inc. v. NRDC, 467 U.S. 837, 842-43 (1984). In ascertaining congressional intent, both EPA and a reviewing court must employ "traditional tools of statutory construction." Id. at 843 n.9.

The determination of which clean coal technologies qualify as repowering justifying an extension under section 409 depends on the definition of "repowering" in section 402(12). That definition, quoted above, provides that "repowering" means "replacement of an existing coal-fired boiler with one of the following clean coal technologies: . . ." The colon is followed by three categories of technologies: (1) seven technologies specifically listed in the statute, or (2) derivatives of the seven listed technologies, and (3) technologies that control multiple combustion emissions, with improved boiler or generation efficiency, and significantly reduced solid waste. Consequently, from the plain language of the statute, it is clear that all three categories, as they follow the colon in the sentence, must involve boiler replacement.[2] This is the reading given in EPA's draft acid rain rules which were circulated for ARAC and interagency review.

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[2] While some of the listed technologies arguably may not require total boiler replacement they all require such extensive modifications of the boiler that they are tantamount to boiler replacement. As discussed below, on page 4, the legislative history bears out this interpretation.

This reading is further supported by an examination of the context of the repowering extension within the statutory scheme, the legislative history, and the overall purpose of Title IV. From the very existence of the repowering extension, one may infer that Congress intended to provide a degree of incentive to use certain Clean Coal Technologies as a compliance strategy under Phase II. There are explicit indications, however, that Congress intended this four-year extension to be limited in scope. Each repowering extension causes substantial emissions increases in excess of the 8.95 million ton statutory cap on SO2 emissions that is the overriding legislative purpose of Title IV. Congress ameliorated this potential emissions impact somewhat by requiring that a percentage of the extension allowances be offset by a pro rata reduction in the overall Phase II allocation. See section 405(a)(2).

In addition, the legislative history is clear that Congress intended the extension to serve only as a necessary accommodation for repowering technologies, not as an open-ended mechanism for exceeding the ceiling on emissions. The Senate Report is explicit that the repowering extension:

> is intended to accommodate the full development and commercialization of certain new or still-developing clean coal technologies as well as any additional time that may be required for their installation.

S. Rep. No. 101-228, 101st Cong., 1st Sess. 312-13 (1989). Elsewhere, the Senate Report emphasizes in even stronger terms that the purpose of the extension is to accommodate the substantial modification or replacement of a boiler that is the hallmark of repowering. The Senate Report also takes pain to distinguish repowering technologies from retrofit technologies that do not require, and were not granted, extensions.

> This extension is provided only for repowering technologies because these technologies require substantial modification or replacement of the boiler and other essential components. In order to utilize these technologies, the unit must be largely rebuilt. In contrast, other clean coal technologies involve retrofits of existing units which do not entail such substantial modifications and attendant protracted shutdowns. No extension with a commensurate temporary loss of emissions reductions, is warranted for these latter technologies.

Id. at 335. Senator Baucus, one of the managers of the bill in conference, reiterated the above-quoted passage almost verbatim

just prior to passage of the final legislation. See Statement of Senator Max Baucus, Cong. Rec. S.16981 (October 27, 1990).

EPA is constrained to interpret the statutory terms in a manner consistent with the paramount legislative objective of limiting utility SO2 emissions to the levels specified by statute. The Agency has done so in its draft acid rain rules by limiting the repowering extension to replacement or substantial modification of a boiler. Conversely, an interpretation of section 402(12) that allowed retrofit technologies not requiring boiler replacement or substantial modification, and hence, not requiring long lead times for implementation, to qualify for the repowering extension would be contrary to express congressional intent.

DOE POSITION

DOE contends that repowering extensions should be allowed for all forms of clean coal technology, regardless of whether there is boiler replacement, so long as the technology is capable of controlling multiple emissions simultaneously, improving boiler efficiency, and significantly reducing waste. In other words, DOE contends that the third category of technologies in the statute[3] does not necessitate boiler replacement or substantial boiler modification.

As stated above, the fact that all three categories of technologies follow the colon in the definition of repowering strongly indicates that boiler replacement or the like is required in all three cases. The statutory scheme and the overall legislative purpose, as well as the Senate Report, are all in alignment with this plain meaning. In contrast, none of these tools of statutory construction support a definition of repowering that would extend to retrofit technologies.

DOE further cites a July 2, 1990 letter from Secretary of Energy Admiral James Watkins to Congressman Regula for the proposition that boiler replacement is not required. Firstly, a letter from the head of an executive agency to a Congressman does not in itself constitute direct evidence of congressional intent.

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[3] "Any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990."

Although the Watkins letter was subsequently endorsed by individual legislators,[4] it could not be relied upon to override the plain meaning of the specific language of the statute when, as discussed above, that plain meaning is also consistent with the statutory context, legislative purpose, and authoritative legislative history. Secondly, the Watkins letter addressed the House bill whereas the final legislation was based on the Senate bill.

It should be noted that DOE's own prior statements on the definition of repowering support an interpretation that would require boiler replacement. See e.g. (1) Memorandum from Doug Carter, DOE, to Rob Fairweather, OMB, "Repowering Benefits," October 16, 1987: "You will recall that 'repowering' is the replacement of a powerplant's basic combustion process with an alternative process," (2) Clean Coal Technology, The New Coal Era, Office of Fossil Fuel, DOE, November 1987: "Repowering technologies, in general, replace a major portion of an existing plant (such as the boiler) with new power generating equipment while retaining other portions of the plant (such as the steam generating equipment)."[5] Thus, while the Watkins letter may represent a clear statement of desired legislative outcome, it is not consistent with the plain language of the statute as passed, and represents a significant departure from DOE's own consistent technical usage of the term "repowering." For this reason also, the Watkins letter should not be relied upon to settle this question of statutory interpretation.

CONCLUSION

The statutory language, statutory scheme, overall legislative purpose, and an unequivocal statement of Senator Baucus, one of the managers of the bill, all support the view that in order to qualify for a repowering extension under section 409 a unit must substantially or totally replace a boiler with a qualifying clean coal technology. In addition, it appears quite clear that the four year extension is intended to provide adequate compliance time for units undertaking substantial boiler replacement projects, and is not intended as an open-ended incentive program for technologies not needing such modifications.

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[4] See 136 Cong. Rec. S 16901 (daily ed. October 27, 1990) (statement of Senator Burdick).

[5] These documents are in the public domain.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

Draft: August 30, 1991

OFFICE OF
GENERAL COUNSEL

MEMORANDUM

SUBJECT: Legal Opinion Regarding: Whether Title IV NOx Requirements Apply to Compensating Units under Section 408 of the Clean Air Act, as Amended

FROM: Gerald H. Yamada
Principal Deputy General Counsel, LE-130

TO: William G. Rosenberg
Assistant Administrator
for Air and Radiation, ANR-443

QUESTION

Do the NOx emission limitation requirements in section 407 of the Clean Air Act as amended apply during Phase I to compensating units under Section 408(c)(1)(B) of the Clean Air Act?

ANSWER

Based on the plain language, statutory scheme, and overall legislative intent of the Act, I conclude that Congress expressly provided in the statute that NOx requirements apply to compensating units. Consequently, EPA lacks discretion to promulgate regulations that would exclude such units from coverage.

BACKGROUND

Section 408(c)(1)(B) of the Clean Air Act provides that if an owner or operator proposes to meet the emissions limitation requirements of Title IV by reducing utilization at or shutting down a unit, the owner or operator must designate in the unit's compliance plan the specific unit(s) that will provide electricity to compensate for the reduced utilization ("the compensating unit"). Section 408(c)(1)(B) then provides that:

> The unit to be used for such compensating generation, which is not otherwise an affected unit under sections 404 and 407, shall be deemed an affected unit under

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> section 404, subject to all of the requirements for such units under this title.

Section 407(a), which contains the applicability provisions for the NOx emission limitations, provides in turn:

> On the date that a coal-fired utility unit becomes an affected unit pursuant to section 404, 405, 409, or on the date a unit subject to the provisions of section 404(d) or 409(b), must meet the SO2 reduction requirements, each such unit shall become an affected unit for purposes of this section and shall be subject to the emission limitations for nitrogen oxides set forth herein.

DISCUSSION

When confronted with a question of statutory interpretation, EPA must inquire

> whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the . . . agency must give effect to the unambiguously expressed intent of Congress. Chevron, U.S.A., Inc. v. Natural Resources Defense Council, Inc., 467 U.S. 837, 842-43 (1984).[1]

Based on the plain language of the statute, it is axiomatic that Section 407 NOx requirements apply to compensating units during Phase I. As set forth above, section 408(c)(1)(B) provides that a compensating unit "shall be deemed an affected unit under section 404, subject to all of the requirements for such units" (emphasis added). Section 407(a) is just as explicit, providing that each "affected unit under section 404 . . . shall become an affected unit for purposes of this section and shall be subject to the emission limitations for nitrogen oxides." This is the reading of the statute that is reflected in the draft acid rain rules that were circulated for ARAC and interagency review.[2]

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[1]In ascertaining congressional intent, EPA must rely on "traditional tools of statutory construction." Id. at 843 n. 9.

[2]Of course, only two types of coal-fired boilers are actually regulated for NOx in Phase I under any circumstances. See section 407(b)(1).

The plain meaning is also consistent with the legislative purpose and statutory scheme. Title IV has a stated goal (in combination with other provisions of the Act) of reducing NOx emissions by two million tons from 1980 levels. Section 401(b). It requires the establishment, in section 407(b)(1), of NOx emissions limits for Phase I affected units. Absent a shift in load to units not subject to NOx limits, the acid rain law would reduce total NOx emissions from each Phase I affected unit by an amount equal to the product of its heat input (expressed in mmBtu) times the reduction in its emissions rate (expressed in lb/mmBtu). Conversely, to the extent that Phase I affected units comply with Title IV by shutting down or reducing utilization and shifting load to compensating units within the meaning of section 408(c)(1)(B), these emissions decreases would not be realized unless the compensating units were also subject to NOx limitations. Congress' concern with total NOx emissions from the universe of Phase I affected units is also reflected in the excess emissions provisions of section 411, which impose stringent penalties for every ton of excess emissions.[3] In light of these factors, it would be anomalous to conclude that Congress did not intend compensating units to comply with NOx requirements.

It may be argued that since Section 408(c)(1)(B) refers to Section 407 in two places, but refers only to Section 404 when it speaks of a compensating unit being deemed "affected" under the Act, Congress did not intend the NOx requirements to apply. This argument is not persuasive, however, since the alleged omission in Section 408 can not overcome the explicit language in Section 407 stating that "on the date that a . . . unit becomes an affected unit pursuant to section[s] 404 . . . [it] shall become an affected unit for purposes of this section (emphasis supplied)."

It also may be argued that since Section 407(a) makes specific reference to Sections 404(d) and 409(b) and not to Section 408(c), Congress did not intend the NOx requirements to apply. This argument too is untenable. The specific reference

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[3]Penalties measured in tons cannot be derived from a simple hourly emissions rate. A utilization rate must also be factored in to the equation. Since the excess emissions penalty is calculated on an annual tonnage basis, it seems clear that Congress intended this calculus to consider the total heat input during the year and the weighted average emissions rate over the course of that year. Such a calculus could be done in several ways, but all of them would need to consider the utilization of the unit.

to Sections 404(d) and 409(b), quoted above, is necessary to clarify that units receiving extensions for SO2 requirements under those sections become subject to NOx emission limitations at the time that the relevant extension expires, and not on the date that the unit becomes an affected unit under Sections 404, 405 or 409. There is no similar ambiguity under Section 408(c)(1)(B), since it is clear from that paragraph that a compensating unit becomes an affected unit on the date that it is (or is required to be) designated under the applicable compliance plan. Furthermore, Section 408(c)(1)(B) already references Section 407, whereas Sections 404(d) and 409(b) do not.

Finally, it is worth noting that if a compensating unit is required to comply with the NOx requirements of Section 407(b)(1), as I believe it should be if it falls within one of the two boiler categories listed under Section 407(b)(1), it will be exempt from any more stringent standards that EPA may promulgate under the update provision of Section 407(b)(2).

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August 6, 1991

BY HAND

Mr. Larry Kertcher
U.S. Environmental Protection Agency
Acid Rain Division, ANR - 445
401 M Street, S.W.
Washington, DC 20460

Initial UARG Comments on June 21
Draft Proposed § 412 Regulations

Dear Mr. Kertcher:

On behalf of the members of the Utility Air Regulatory Group (UARG), we are writing to express our concerns with the June 21 draft § 412 regulations released to the Acid Rain Advisory Committee (ARAC). While a number of these concerns were expressed orally at the July 15 ARAC subcommittee meeting, this letter highlights UARG's concerns in writing.

UARG is concerned that EPA has not taken most of the utility industry's comments into account, has not even noted in the preamble the existence of opposing views on most of the issues, and has not solicited comments on these issues. Even if EPA does nothing else in response to this letter, the Agency at a minimum should expand the preamble to the proposed rules by raising in a balanced fashion the issues discussed repeatedly by industry representatives during the ARAC subcommittee meetings and summarized in this letter, and should request comments on these issues and on alternatives to implementing § 412.

I. Certification and Quality Control Standards for Emission Monitors

In January of this year, EPA agreed at the ARAC meeting that it would use the performance specifications and quality control (QC) provisions applicable to monitors at electric utility units subject to 40 C.F.R. Part 60, Subpart Da ("Subpart Da") as a starting point for the QC provisions required by § 412(a). UARG understood this agreement to mean that any tightening of these provisions, many of which have been in use only since 1988,[1/] would be carefully considered by EPA and would be adequately justified by the performance data from monitors at Subpart Da units.

Instead of taking this reasonable approach, EPA has developed an approach that asks if some individual Subpart Da monitors have at any time achieved a level of performance exceeding Da (Appendix F) requirements. If so, EPA has apparently concluded that such higher level of performance should be mandated for all monitors at all times without exception. EPA's rationale for this approach appears to be that monitor performance will improve so significantly over the next months, as companies procure monitors to meet the statutory deadlines,[2/] that the levels of performance that have been achieved from time to time at individual Subpart Da monitors in the past will from now on be achievable by all monitors under all conditions.

This rationale fails to take into account two important points. First, the fact that individual monitors have met more

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1/ 52 Fed. Reg. 21003, 21007 (1987) (adding Appendix F to 40 C.F.R. Part 60).

2/ Phase I units must have monitors installed in time to ensure operation and certification under EPA's regulations by November 15, 1993.

minimum, the Agency should explain the issue in the preamble, and solicit comments on whether a quarterly bias test is needed.[5/]

B. The Quarterly Bias Test

If EPA does not delete the bias test from the proposal, the Agency should at least (in addition to requesting comments on whether to delete the test) explain better the test and the potential problems that exist in passing the test. As UARG presented at the ARAC subcommittee meeting, existing RATA data from monitors at Subpart Da units show that a high percentage of the RATAs (about 70 percent) would not have passed the bias test.[6/] Again, UARG believes that EPA's "bias" test does not provide a true indication of bias, but rather reflects random errors and variability in the emission monitor and Reference Methods.

Moreover, other problems exist with the bias test. For example, even a monitor that (by chance) has a very good relative accuracy (e.g., below 5 percent) in a given test could still fail

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5/ EPA noted at the ARAC meeting that its primary reason for a quarterly relative accuracy test audit (RATA) is to provide data to calculate "bias." The need for a quarterly RATA goes away if the bias test is deleted. Thus, EPA should also request comments on whether an annual RATA (along with quarterly and daily calibration error tests) is sufficient to implement the QC mandate of § 412(a). In conjunction with this issue, EPA in the preamble should note the significant manpower burdens that would be associated with quarterly RATAs. For a medium-sized utility system, a requirement for quarterly RATAs would dictate conducting RATAs almost constantly for 4-6 weeks every quarter.

6/ As explained above, UARG believes that the fact that no bias test existed when these RATAs were performed is irrelevant. Knowing that fact would not have enabled operators to conduct the RATA differently or to have done anything different with their monitors, which were in the best working order possible at the time of the RATAs. Moreover, increased maintenance of the monitors during the previous quarter would not have enhanced the level of monitor performance during the RATAs.

the draft bias test, if the mean difference is greater than the confidence coefficient.[7/] It seems ridiculous to require failure of a QC test when relative accuracy is good.

In short, EPA should solicit comments on ways to improve the bias test, if it is proposed. Again, however, UARG urges EPA not to propose the bias test, but to rely on the daily calibration error test to minimize any possibility of significant bias.

C. Relative Accuracy

The current Subpart Da (Appendix F) relative accuracy standard is 20 percent. Based upon the fact that individual monitors have occasionally achieved 10 percent (or less) relative accuracy, EPA's draft requires 10 percent to be met by all monitors at all times in the future.

For reasons explained previously, UARG believes that such a stringent relative accuracy standard is unjustified. With such a low standard, the variability of the Reference Methods alone would dictate to a significant extent whether a given monitor would meet the standard in any given RATA.[8/] Again, the only way to meet the standard would be to keep conducting RATAs until the standard was satisfied (and the bias standard was also satisfied, if that test is retained). This is simply a game of chance, which would not improve the accuracy of emission measurements.

7/ See Draft rules, Appendix A, § 8.5.

8/ For example, collaborative testing by EPA has shown that the intralab standard deviation of Reference Method 6 (SO_2) is 4 percent. Assuming a normal distribution, that means that about 95 percent of intralab Reference Method 6 tests are within plus or minus 8 percent of the mean value. For Method 7 (NO_x), the intralab standard deviation is 6.6 percent, so that about 95 percent of the tests fall within 13.2 percent of the mean value.

exception, on deletion of the bias test, and on whether to consider now a future, more stringent relative accuracy standard.

III. Missing Data Estimation

Although Congress indicated a desire in § 412(a) for data to be collected by CEMS or an alternative, Congress also recognized that these techniques would not achieve 100 percent data capture. Thus, § 412(d) provides that a source owner/operator must be given an opportunity to supply emissions information satisfactory to the Administrator if data are not collected from a CEMS or an alternative. If such information is not provided, the source owner/operator must assume that the unit was operating in an uncontrolled manner.

To reduce the administration burdens associated with determining on a case-by-case basis whether information supplied to EPA is "satisfactory," EPA has attempted to develop a generic, pre-approved method of filling in missing data. While UARG generally agrees with the need to establish a generic procedure, UARG is concerned with various aspects of the procedures that EPA has developed.[15/]

15/ UARG also notes that EPA has failed to provide an acceptable procedure for calculating CEM availability during the first year of monitor or unit operation. See Draft rules § 75.12(d)(Equation 5). First, use of the rolling operating year to calculate availability for existing units during their first year of monitoring will lead to absurd results because those units will most likely have high operating hours during the 365 days before the monitor was installed, but no continuous monitoring data. Second, and of much greater concern, is application of the procedure to units that begin commercial operation after the start of the allowance trading program. Those new units would be penalized during their first months of commercial operation by daily calculation of availability because their total number of operating hours will be too low in the beginning to support even an acceptable amount of missing data.

(continued...)

relationship should be used. If availability drops below 90 percent, a more conservative procedure can be used, such as maximum flow ever recorded for a given load. (Load data, of course, will always be available.)

In the draft proposal, EPA applies the same type of estimation and overestimation techniques to missing flow data as to missing emissions data. The unbiased estimation techniques should be revised as explained in the June 20, 1991 letter from UARG to EPA, discussing the flow versus load correlation approach.[22/] This approach provides a better substitute flow value than does the "hour before/after" method or other estimation techniques. At a minimum, EPA's proposal should solicit comments on this approach.

Finally, to satisfy the § 412 requirement that flow be measured, EPA could consider a minimum annual flow monitor availability requirement (e.g., 75 percent, as used in Subpart Da for emission monitors). In short, UARG believes that there is no legal or technical basis for deliberately overestimating missing flow data as EPA has suggested in its draft rules.[23/]

22/ See Attachment 2.

23/ At a minimum, EPA should adopt an alternative flow monitor availability standard for use during Phase I. In a preliminary issue paper on missing data submitted to the ARAC subcommittee, EPA noted that "since there is considerably less industry experience with proper flow monitor operation and maintenance . . . . high-biased estimates may be used in Phase I only for filling in missing flow data substantially below the [90 percent] threshold, say, less than 80 percent." ARAC Meeting Materials, Document Number E-27, EPA "Issue Paper - Alternative Proposals for Missing Data Periods," p. 9.

IV. Alternatives

Under § 412, EPA may approve alternatives to CEMS that have the same precision, reliability, accessibility, and timeliness ("PRAT") as CEMS. UARG has made clear that it is most concerned about alternatives in two situations: for oil-fired units (SO_2 and flow, and NO_x), and for flow at units that cannot properly locate a flow monitor (these tend to be older, smaller Phase II units).[24/]

EPA has ignored all of the discussion that took place at the ARAC subcommittee regarding the appropriateness of pre-approved alternatives in these situations.[25/] Instead, the Agency has developed a stringent, burdensome certification procedure for alternatives and articulated an extremely narrow interpretation of PRAT. While an oil sampling and analysis program for SO_2 could potentially be developed that would meet EPA's interpretation of PRAT,[26/] UARG doubts that any oil sampling and analysis program could pass the draft certification procedure (especially the t-test), which is so stringent that, in all likelihood, not even two side-by-side certified CEMs could pass.

With regard to flow, UARG doubts that any available, economical alternatives could satisfy the draft PRAT

24/ UARG was concerned about SO_2 alternatives for coal-fired units at the beginning of the ARAC process. In order to strike a compromise with EPA, however, UARG decided (with some member dissents) not to argue for any SO_2 alternatives in lieu of CEMs. UARG's compromise has apparently not achieved anything -- EPA has continued to push for a completely unreasonable implementation of § 412's "alternatives" provision.

25/ The only response of EPA has been to include a de minimis exception for gas-fired units. This exception is addressed in the next section of these comments.

26/ While it might meet PRAT, such a program would be much more stringent than would be needed to obtain accurate SO_2 values.

ATTACHMENT 1

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June 4, 1991

VIA OVERNIGHT DELIVERY

Mr. Larry Kertcher
U.S. Environmental Protection Agency
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401 M Street, S.W.
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Results of Different Methods of
Estimating Missing Data

Dear Mr. Kertcher:

As you requested, the Utility Air Regulatory Group (UARG) has performed additional analyses of the missing data estimation procedures.[1/] This letter describes the analyses, the results, and the implications of the results for the § 412 regulations.

The Analyses

Based upon our discussions, UARG examined four new methods of estimating missing data, in addition to the "2N" method and the "BIN" method. These are (1) the "1N" method; (2) the "N/2" (i.e., one-half N) method; (3) the "N Before" method (which uses only the N hours before the missing data gap); and (4) the "Hour Before/After" method (which uses only the hour before and the hour after the missing data gap).

[1/] These analyses were performed by W.S. Pitts Consulting, Inc. in the manner described in previous reports submitted to the Agency.

Each method was run using the standard missing data pattern developed by UARG (see Table 1). You may recall that the durations and relative number of periods per year for this standard pattern are based upon the results of UARG's survey of Subpart Da units. Thus, this pattern represents the best available approximation of the missing data patterns that affected units under Title IV will have.[2/]

The standard pattern assumes that approximately ten percent (900 hours) of CEM data is missing and must be estimated. UARG chose ten percent because UARG proposes that ten percent be the limit for the amount of missing data that may be filled in by the estimation procedure, assuming Subpart Da-type quality assurance/quality control (QA/QC) requirements. While the available data from Subpart Da units suggest that 90 percent data capture is a realistic goal for new units able to design the CEM system in the unit, achieving 90 percent or better data capture may be a challenge for retrofit CEM applications, based on the Pennsylvania experience.[3/]

In addition to running the normal estimation procedures, which apply no overestimation or bias techniques in conjunction with the standard pattern, UARG developed and evaluated for EPA seven overestimation or bias techniques.[4/] Table 2 summarizes

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[2/]The sensitivity analysis sent to you by Wallace Pitts on April 10, 1991 shows that varying the missing data patterns has little effect on the results of the estimation procedures.

[3/]Of course, if EPA proposes to make the § 412 QA/QC provisions much more stringent than the Subpart Da QA/QC provisions, UARG would need to reevaluate its current position that ten percent is a reasonable limit for use of the estimation procedure.

[4/]At the April ARAC meeting, David Hawkins objected to the use of the term "bias" in applying these techniques, because in his view the estimation procedures yield results that bear no relation to what happened during the data gap. UARG believes that "bias" is an appropriate term, and that Mr. Hawkins is incorrect. The estimation methods do bear a relation to the

(continued...)

"max-min" range than the other methods.[5/] Upon further reflection, this makes sense, because of the autocorrelation principle. The farther that the data used to estimate the data in the missing data gap are from the gap itself, the less autocorrelated the data are compared to what actually happened in the gap. Thus, in general, the "Hour Before/After" method is better than "N/2," which is better than "1N," which is better than "2N."

Not only is the "Hour Before/After" the best method, but use of that method would avoid the problem of closely spaced missing data gaps. Using any of the "N" methods, there is a chance of overlap of an "N" period and a subsequent (or preceding) data gap. By definition, this problem cannot occur with use of the "Hour Before/After" method. UARG therefore recommends the use of the "Hour Before/After" method in the draft rules for filling in missing data.

Second, the results from the application of the seven bias techniques show the harsh consequences that almost any bias technique will produce. For example, "Bias A," the technique suggested in the EPA Issue Paper presented at the last ARAC meeting, results in about 2% average overestimation of annual SO_2 tons for the compliance coal case (using the "Hour Before/After" procedure). The average overestimation of annual SO_2 tons for the scrubbed unit case is even higher, about 5%. See Tables 4 and 5. For a compliance coal unit with annual SO_2 emission allowances of 20,000 tons, these results mean that overestimation or bias technique "A" on average would add 400 tons to the annual SO_2 emissions determination compared to the no bias case, at a cost (assuming a $500/ton value for SO_2 allowances) of $200,000

[5/] The only exception is that the average percent difference of the "BIN" method in the scrubbed unit case is slightly lower than the average percent difference of the "Hour Before/After" method. However, since the range for the "BIN" method is significantly greater than the range for the "Hour Before/After" method, the "Hour Before/After" method appears to be the best choice even for the scrubbed unit case.

per year. The risk of such a large annual economic penalty for missing data would be high, because many units would likely have a number and duration of missing data periods similar to those in UARG's standard pattern, as explained above.

Because the risk of such a large annual economic penalty would be so great, requiring use of this type of overestimation technique would force, in effect, the installation and use of redundant CEMs. In fact, imposition of any overestimation technique for filling in missing data that would create a risk of an annual economic penalty on the order of $50,000 or more per unit would likely lead many utilities to consider seriously the installation of redundant CEMs. Most of the bias techniques examined would produce such a risk. UARG would, of course, object strenuously to any proposed rule that would have the practical effect of requiring redundant CEMs.

The results of bias techniques "C" and "D" reveal that even a bias attributed only to the one 48-hour missing data period in UARG's standard pattern would produce harsh results. Using the "Hour Before/After" estimation method, such a bias would overestimate annual SO_2 emissions on average about 0.4 percent for a compliance coal unit and about one percent for a scrubbed unit. For a compliance coal unit with 20,000 SO_2 allowances, this translates to an additional 80 tons of SO_2 emissions with an annual value of $40,000 (assuming $500/ton). While perhaps not a high enough annual economic risk to lead a utility to install redundant CEMs, UARG believes that such an economic penalty is unjustified.

UARG disagrees with those that argue that overestimation is justified in order to encourage high data capture and to discourage missing data periods, especially longer periods. First, the notion that utilities would devote less attention to CEM operation and maintenance if overestimation of missing data were not required is unsupported by the evidence. If that were the case, Subpart Da units, which are required to achieve only about 75% data capture, would not be regularly attaining over 90%

data capture. The fact is that utilities attempt to capture as much data as is reasonably possible. EPA need not penalize utilities to accomplish that result.[6/]

Second, imposing a requirement for use of an overestimation technique ignores the fact that at least some units each year will have no control over events that lead to some missing data periods that may last one or two days. In the ARAC process, we heard of a utility that had a monitor break during a winter storm, which prevented the repair of the monitor and use of a portable backup monitor because workers were not permitted up the stack for safety reasons. Another utility relayed a story that lightning set fire to one plant's stack. And what if a utility were to hire a testing company after discovering that a problem could not be fixed quickly, but the testing company had no crew available or the assigned crew had car trouble? Utilities should not be punished for events that are beyond their control.

EPA may be correct that many longer missing data periods (e.g., greater than 24 hours) can be avoided by the prompt action of the company to repair the installed monitor or to place a portable monitor in service. Yet, this will not always be the case.[7/] And rather than harshly penalize a utility for events

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[6/]EPA should recall that UARG is not proposing unlimited use of the missing data estimation procedure. The 90% threshold (again, assuming reasonable QA/QC requirements), coupled with a limit on the number of longer periods for which the procedure could be used even if the threshold had not been reached, place reasonable limits on using the procedure without introducing bias. Moreover, it encourages high data capture to avoid falling below the 90% level during the year.

[7/]That is, UARG disputes the suggestion (attributed to NRECA) in EPA's Issue Paper E27 that a company should always be able to place a portable backup monitor in service for any period lasting over 24 hours. A simple example shows why this is so. Suppose a company discovers a monitor problem that, after a few hours of diagnosis, it thinks it can fix relatively easily. Therefore the company does not call a testing company to bring in a portable monitor. Suppose that several attempts at repair fail, and a much more extensive problem is discovered that

(continued...)

beyond its control, EPA should allow use of an unbiased estimation method for at least a limited number of longer periods.

Finally, it is perhaps most important to recognize that overestimation techniques that would in effect force utilities to install redundant CEMs would have virtually no real world benefit. As the results of the "no bias" estimation procedures show, see Table 3, the annual SO_2 tonnages determined using UARG's suggested approach will be extremely close to the "true" annual SO_2 tonnages that would be determined if the CEM achieved 100% data capture. Purchase and use of a redundant CEM to increase data capture would therefore not produce more accurate annual SO_2 emissions values. In sum, EPA should not write rules that would cost the utility industry tens of millions of dollars but have no real world benefits.

Conclusion

The results of UARG's additional missing data analyses reveal that the "Hour Before/After" estimation method produces the best determination of annual SO_2 tonnages of all the estimation methods analyzed. Moreover, examination of various bias techniques shows the unreasonable impacts associated with those techniques. All but the most innocuous bias technique would likely lead utilities to install and use redundant CEMs, with virtually no benefit for the determination of annual SO_2 emissions. EPA should not draft rules that force costs with no commensurate benefits.

7/ (...continued)
requires ordering a new part not typically kept in stock. By the time a testing company is able to be hired and comes to the plant, it is likely that more than 24 hours would have passed. (One way to avoid this situation would be for every plant in the country to purchase, and have persons who could use, a portable monitor. UARG believes this would be as unreasonable as having to install redundant CEMs.)

If you have any questions or need additional analyses, please do not hesitate to call.

Sincerely,

Mel S. Schulze

MSS/nbt
cc: Doris Price

Table 1. Standard Pattern for Missing Data Periods		
Duration (hours)	Number per year	Hours
3	178	534
6	29	174
12	6	72
24	3	72
48	1	48
		900

Table 2. Missing Data Bias Techniques

Duration (hours)	Bias 1	Bias 2	Bias 3	Bias A	Bias B	Bias C	Bias D
3	none	none	none	none	none	none	none
6	none	none	none	MD30	none	none	none
12	est +5%	MHr30	MHr90	MD30	MD30	none	none
24	est +7%	MHr30	MHr90	MD30	MD30	none	none
48	est +9%	MHr30	MHr90	MHr90	MHr90	MHr90	MHr30

Bias Methods: "est + _%" is (result from unbiased estimation method) times (1 + (_% /100))

"MHr__" is maximum hourly SO_2 value recorded in the previous 30 or 90 days (calendar month or quarter)

"MD__" is maximum daily SO_2 average recorded in the previous 30 or 90 days (calendar month or quarter)

Table 3. Comparison of Unbiased Estimation methods. Percent difference between estimated and actual annual SO_2 tons emitted for load profile 1. Assumes 20% RSD and Standard Pattern for Missing Data (900 hours missing data per year). Values represent the averages of 3 500-year simulations.

	Compliance Coal			FGD System		
Method	MIN	AVG	MAX	MIN	AVG	MAX
2 N	-0.364	0.003	0.335	-1.403	-0.095	0.780
1 N	-0.294	0.003	0.295	-1.320	-0.067	0.760
N/2	-0.275	0.001	0.275	-1.181	-0.049	0.739
N Before	-0.500	-0.003	0.444	-1.513	-0.066	0.962
Hour Before/After	-0.214	0.001	0.204	-0.838	-0.041	0.696
BIN	-0.524	0.005	0.511	-1.424	-0.008	1.058

Table 4. Effect of Adding Bias on Methods for Estimating Missing Data. Percent Difference Between Estimated and Actual Annual Tons SO_2 emitted for load Profile 1. Compliance Coal 20 % RSD and Standard Pattern for Missing Data (900 hours Missing Data per Year). Values represent the averages of 3 500-year simulations.

	2 N			1 N			N/2			N Before			Hour Before/After		
Bias	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
NONE	-0.364	0.003	0.335	-0.294	0.003	0.295	-0.275	0.001	0.275	-0.500	-0.003	0.444	-0.214	0.001	0.204
1	-0.207	0.151	0.494	-0.149	0.150	0.452	-0.125	0.149	0.444	-0.364	0.144	0.613	-0.062	0.148	0.374
2	0.720	1.410	2.247	0.726	1.410	2.255	0.736	1.410	2.258	0.720	1.410	2.291	0.740	1.410	2.258
3	0.979	1.793	2.897	0.982	1.792	2.906	0.987	1.792	2.904	0.986	1.792	2.940	0.993	1.792	2.900
A	1.129	1.963	3.001	1.132	1.963	3.013	1.136	1.963	3.021	1.143	1.962	3.031	1.136	1.963	3.021
B	0.427	1.135	2.055	0.436	1.134	2.075	0.441	1.134	2.071	0.446	1.134	2.105	0.444	1.134	2.066
C	-0.045	0.449	1.034	-0.032	0.449	1.003	-0.035	0.448	1.025	-0.100	0.446	1.038	-0.056	0.450	1.038
D	-0.130	0.356	0.899	-0.131	0.356	0.907	-0.125	0.355	0.895	-0.221	0.353	0.919	-0.118	0.357	0.890

Table 5. Effect of Adding Bias on Methods for Estimating Missing Data. Percent Difference Between Estimated and Actual Annual Tons SO_2 emitted for load Profile 1 FGD System, Coal 20 % RSD and Standard Pattern for Missing Data (900 hours Missing Data per Year). Values represent the averages of 3 500-year simulations.

	2 N			1 N			N/2			N Before			Hour Before/After		
Bias	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
NONE	-1.403	-0.095	0.780	-1.320	-0.067	0.760	-1.181	-0.049	0.739	-1.513	-0.066	0.962	-0.838	-0.041	0.696
1	-1.236	0.050	0.938	-1.157	0.078	0.932	-1.015	0.097	0.977	-1.385	0.080	1.153	-0.648	0.105	0.887
2	2.302	4.159	7.348	2.293	4.178	7.363	2.313	4.189	7.306	2.188	4.176	7.294	2.304	4.192	7.302
3	3.572	5.469	10.897	3.576	5.487	10.897	3.528	5.498	10.870	3.545	5.486	10.872	3.515	5.502	10.851
A	2.889	4.864	9.394	2.937	4.878	9.416	2.945	4.886	9.427	2.945	4.874	9.379	2.945	4.886	9.427
B	1.490	2.922	6.544	1.530	2.941	6.566	1.522	2.952	6.540	1.457	2.940	6.522	1.513	2.956	6.535
C	-0.125	1.293	4.616	-0.006	1.317	4.630	0.054	1.333	4.567	-0.069	1.321	4.553	0.115	1.340	4.544
D	-0.502	0.960	3.324	-0.387	0.984	3.259	-0.317	1.000	3.154	-0.494	0.988	3.325	-0.354	1.008	3.104

ATTACHMENT 2

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June 20, 1991

VIA OVERNIGHT DELIVERY

Mr. Larry Kertcher
U.S. Environmental Protection Agency
Acid Rain Division, ANR - 445
401 M Street, S.W.
Washington, DC 20460

Filling in Missing Flow Data For Units With A Flow Monitor

Dear Mr. Kertcher:

In the recent past, we recommended, based upon an analysis by W.S. Pitts Consulting, Inc., that EPA specify the "Hour Before/After" estimation method for filling in missing SO_2 emissions data. To date, however, neither we nor the ARAC Emissions Monitoring Subcommittee has made any suggestion regarding how to fill in missing volumetric flow data. This letter recommends a method for filling in missing flow data, for those units that must install a flow monitor.

As we have previously indicated, not all units should be required under the § 412 regulations to install a flow monitor. For example, for oil- and oil/gas-fired units burning greater than 10 percent oil, obtaining SO_2 tons using a fuel flow meter coupled with oil sampling and analysis should be deemed acceptable by EPA. Moreoever, coal-fired units that cannot properly locate a flow monitor should be allowed to use measured coal weights coupled with coal sampling and analysis to determine SO_2 tons.

For those units that must install a flow monitor, however, it is inevitable that there will be some periods during the year when that monitor is inoperative or provides invalid data. During those periods, another method must be used to supply flow information in order to calculate SO_2 tons. An "Hour Before/After" estimation method is inadequate for addressing missing flow data, because flow (unlike SO_2 ppm emissions) is a direct function of unit load. The enclosed Memorandum prepared by Systems Applications International (SAI) presents and analyzes a method for estimating missing flow data.

The SAI Memorandum recommends the use of a regression equation based upon volumetric flow, load, and diluent (CO_2 or O_2) concentrations. The equation would be developed and periodically updated using the measured parameters, and then used as needed to fill in missing flow data.

SAI tested the regression equation method with a data set provided by Central Illinois Public Service. After developing the regression equation, SAI applied the simulation technique used by W.S. Pitts Consulting for evaluating various methods for estimating missing data. The results show that the regression equation method for estimating missing flow data is extremely accurate.[1/] Accordingly, we recommend that such a method be included in the proposed § 412 rules under development at EPA.

1/ SAI assumed 10 percent missing data and UARG's standard missing data pattern in doing the evaluation. While these appear to be reasonable assumptions given the limited data base developed by EPA on data capture by flow monitors, we cannot endorse any specific threshold for using the regression estimation procedure until additional data are obtained on flow monitor availability. We are particularly concerned that a reasonable threshold be established for the use of the procedure, because obtaining and using a backup measurement method will be much more difficult for flow than for SO_2.

If you have any questions, please do not hesitate to call.

Sincerely,

Mel S. Schulze

MSS/nbt
Enclosure
cc: Doris Price

Systems Applications International

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919-782-1033 Facsimile 919-782-1716
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MEMORANDUM

TO: Pat DalPorto, Chairman
UARG Measurement Techniques Committee

FROM: Ralph L. Roberson
John Langstaff
Katherine McAuliffe

DATE: June 19, 1991

SUBJECT: Alternative Procedure for Estimating Volumetric Flow Rates

INTRODUCTION

The Utility Air Regulatory Group (UARG) is investigating several procedures for estimating pollutant concentrations when continuous emission monitoring (CEM) data are not available. In this memorandum, Systems Applications International (SAI) examines a procedure for estimating volumetric flow rates from other routinely monitored parameters. The procedure is based on conducting a regression analysis using previously obtained volumetric flow rates, generating load, and excess air data. To implement this approach, an owner/operator would develop a regression relationship from historical data and use the results to estimate volumetric flow rates during periods when a flow monitor is inoperative.

DESCRIPTION OF DATA SET

Central Illinois Public Service (CIPS) provided SAI with a data set covering approximately one year of operation of its Coffeen Generating Station. The Coffeen Station consists of two cyclone-fired boilers with a combined generating capacity of approximately 915 MWe. The two boilers exhaust through a common stack. All monitoring (pollutant and flow) of

the two units is conducted in a common stack. The data set provided by CIPS consists of over 6,000 hourly observations of several parameters including generating load for each unit (MWe), volumetric flow rate (10^3 acfm), and CO_2 concentration (%). Figure 1 is a plot of boiler load versus measured volumetric flow rate.

REGRESSION ANALYSIS

Based on our knowledge of the relationship among volumetric flow and other operating parameters, SAI set up the following equation.

$$Q = \alpha\ (L_1) + \beta\ (L_2) + \gamma\ (CO_2) + \delta$$

Where:

Q = volumetric flow rate (10^3 acfm)
α, β, γ, δ = regression coefficients and intercept
L_1, L_2 = generation load for Boilers 1 and 2 (MWe)
CO_2 = stack CO_2 concentration (%)

SAI used a SAS® computer procedure to conduct the regression analysis. The regression analysis yielded the following:

$$Q = 3.82(L_1) + 3.82(L_2) - 77.9(CO_2) + 992$$

This equation can be rewritten as:

$$Q = 3.82(L_1 + L_2) - 77.9(CO_2) + 992$$

The SAS® computer procedure also provides diagnostic information regarding the "goodness" of fit. The R^2 for the regression equation is 0.97, and the root mean square error (RMSE) is 116. Since R^2 = 0.97, we know that 97 percent of the variance in volumetric flow is predictable from the regression variables (i.e., generating load and stack CO_2 concentration). The root mean square error is an estimate of the standard deviation of the error term. The error term is the difference between the predicted value and the measured value.

EXAMPLE CALCULATION

Suppose that the flow monitor is inoperative for an hour during which the following data are obtained:

L_1 = 300 MWe
L_2 = 550 MWe
CO_2 = 12%

The estimated volumetric flow rate would be given by:

$$Q = 3.82(300 + 550) - 77.9(12) + 992$$
$$= 3{,}330 \times 10^3 \text{ acfm.}$$

ADDITIONAL ANALYSIS

In addition to the R^2 and root mean square error, it is instructive to examine how well the regression technique would work in practice. We have used an approach developed by W. S. Pitts Consulting for evaluating various techniques for estimating missing data. That is, we eliminate 10 percent of the hourly flow values and replace the eliminated values with regression estimates. In the absence of information regarding the frequency and duration of flow monitoring outages, we have used the same

missing data pattern as determined from the Utility Air Regulatory Group's survey of CEM systems at Subpart Da plants.

We calculate SO_2 mass emissions by multiplying hourly flow values times hourly SO_2 concentrations, as determined by the stack CEM system. SO_2 mass emissions are then summed over the approximate 12 month operating period. We compare "true" emissions to estimated emissions, where "true" emissions are based on the complete data set and estimated emissions are based on actual data with 10 percent of the hourly flow values estimated from the regression equation.

In order to determine the sensitivity of when the missing data occurs, we repeated the analysis 500 times. For each repetition, the same 10 percent missing data pattern is used; however, the exact hours of flow data that were eliminated varied from repetition to repetition.

The results of our analyses are expressed as a percent difference. Percent difference is computed by subtracting "true" total emissions from estimated total emissions, dividing the difference by "true" total emissions, and multiplying the quotient times 100 percent, for each of the 500 repetitions. The 500 repetitions yield a distribution of percent differences. To characterize the distribution of differences, we run the SAS® Univariate Procedure. The results are as follows:

Mean	= 0.02%
Standard Deviation	= 0.043%
10th Percentile	= -0.035%
90th Percentile	= 0.070%

The above results show that a regression equation can be used to estimate up to 10 percent of missing hourly flow values and the resulting computation of SO_2 mass emissions are almost identical to what would be obtained without any missing flow data.

SUMMARY

We have conducted a regression analysis that predicts hourly flow rates from hourly load and hourly CO_2 data. The R^2 and root mean square error indicate that the regression equation is a good fit to the data. Moreover, our analysis shows that substituting up to 10 percent of hourly flow values with regression estimates yields almost the same number of tons of SO_2 that are obtained when all of the measured hourly flow values are used. We believe that the regression technique is a reasonable approach to estimate volumetric flow rates during limited periods of missing data.

RLR/chw

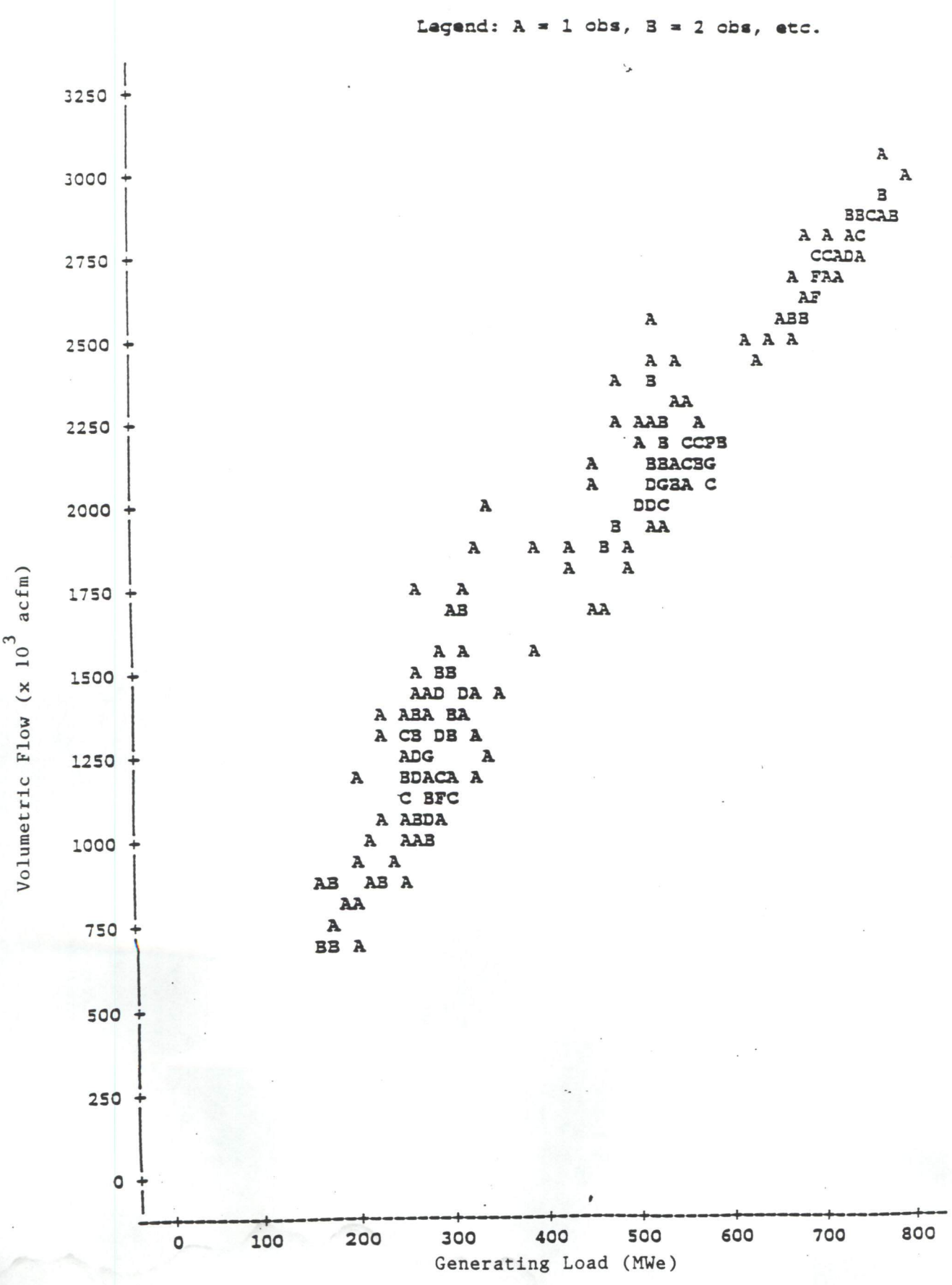

Figure 1. Plot of Volumetric Flow Versus Load.

ATTACHMENT 3

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April 25, 1991

VIA OVERNIGHT DELIVERY

To: ARAC Emissions Monitoring Subcommittee

Utility Air Regulatory Group
Proposal on Alternative Methods for Determining SO_2 and NO_x Emissions From Oil-Fired Units and Oil/Gas-Fired Units Burning Greater Than 10 Percent Oil

At the March Emissions Monitoring Subcommittee Meeting, the Utility Air Regulatory Group (UARG) agreed to provide the Subcommittee with a proposal on alternative methods for determining SO_2 and NO_x emissions from oil-fired units and oil/gas-fired units burning greater than 10 percent oil. Houston Lighting and Power Company and Texas Utilities Electric Company (HL&P/TU) agreed to take the lead on a similar proposal for oil/gas-fired units that burn 10 percent or less oil. This letter and the enclosed report describe UARG's proposal.[1/]

SO_2

As discussed in previous UARG papers, oil sampling and analysis plus measurement of fuel flow (or some acceptable alternative to fuel flow) provide an equivalent, if not superior, method for determining SO_2 emissions (in tons) as compared to use of an SO_2 continuous emission monitor (CEM) and a flow monitor. In discussions with HL&P/TU, it was determined that UARG's

1/ Because not all UARG members have had an opportunity to review this proposal, the proposal should be considered preliminary at this time.

proposal for oil sampling and analysis/fuel flow would be nearly identical to the HL&P/TU proposal. As a result, UARG is not submitting a separate SO_2 proposal. Rather, UARG joins in and fully supports the April 24 HL&P/TU proposal recently submitted to the Subcommittee. Oil/gas-fired units burning 10 percent or less oil, oil/gas-fired units burning greater than 10 percent oil, and oil-fired units should all have the option of using either the "Maximum SO_2 Monitoring Method" or the "Daily SO_2 Monitoring Method" described in the HL&P/TU submittal. The first method would provide a highly conservative (i.e., biased high) determination of SO_2 emissions in tons, while the second method would provide a more accurate determination.[2/]

$\underline{NO_x}$

The UARG proposal for determining NO_x is provided in the enclosed paper prepared by Energy Technology Consultants, Inc. The proposal is similar to that in the HL&P/TU submittal. The major difference is that two NO_x versus load curves would be needed for oil/gas-fired units burning greater than 10 percent

---

2/ If EPA were to require calculation and reporting of hourly SO_2 emissions for oil-fired and oil/gas-fired units burning greater than 10 percent oil, a position with which UARG disagrees, one could do so using hourly fuel flow measurements (or an alternative such as hourly generation and a heat rate curve) plus the sulfur content of the oil (daily or as delivered maximum). The tank sounding method described in the HL&P/TU report as an alternative to fuel flow monitoring probably would not be suitable for determining hourly SO_2 emissions. For those using the "daily SO_2 monitoring method," the assumption of a constant sulfur-in-oil level for each hour of the day based on a sulfur analysis of one daily sample is reasonable, given the homogeneity of sulfur in oil. This lack of within-day sulfur variability is also why UARG believes that a once-per-day grab sample, as opposed to a composite daily drip sample, is adequate for assessing the sulfur content of the oil for all oil/gas- and oil-fired units.

oil: one for gas firing and one for oil firing. (Oil-only units would, of course, need only one curve.)

UARG would be happy to discuss these proposals in more detail at next week's ARAC meeting. If anyone has any questions, please do not hesitate to call.

Sincerely,

Mel S. Schulze

cc: Mr. Larry Kertcher
Mr. Louis Paley
Ms. Doris Price
Ms. Margaret Sheppard
Mr. Tony Wayne
Mr. Ted Williams

ETEC

ENERGY
TECHNOLOGY
CONSULTANTS, INC.

ALTERNATE NOx EMISSION MONITORING METHOD

Oil and Gas Utility Boilers Firing Greater Than 10% Oil

Prepared for

UTILITY AIR REGULATORY GROUP

Prepared by

Energy Technology Consultants, Inc.

April 1991

ETEC91-20065

ENERGY TECHNOLOGY CONSULTANTS, INC.
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1.0 INTRODUCTION

Section 412(a) of the 1990 Clean Air Act Amendments (CAAA90) requires monitoring of nitrogen oxides (NOx) from "Affected units". Included in the in those units classified as "Affected units " are oil-fired units and oil/gas-fired units that burn greater than ten (10) percent oil. No use is specified for the monitored NOx emissions from oil and gas/oil-fired units under Title IV. Provisions under Section 412(a) specify that Affected units must install Continuous Emission Monitoring Systems (CEMS) or use an alternative method approved by EPA. This report presents an alternative method to CEMS for obtaining NOx emissions from this class of Affected units.

2.0 NOx ALTERNATIVE METHOD

For most liquid and gaseous fuels used in the utility industry, the NOx emission characteristics of utility sized boilers are, for the most part, repeatable over time provided that the basic design of the boiler remains fixed and the fuel properties do not change considerably. This property of boilers using these fuels allows determination of the NOx emissions (lb/MMBtu) given the NOx versus load characteristics and the average load over a specific period of time. The following paragraphs describe the theoretical basis for this alternate method of NOx monitoring and the procedures recommended for use with this alternative method.

2.1 NOx Formation

NOx formation in fossil fuel utility boilers results from the thermal fixation of atmospheric nitrogen in the combustion air and the conversion of chemically bound nitrogen in the fuel. The thermal fixation of atmospheric nitrogen to nitrogen oxides is termed "Thermal NOx Formation". The major species formed are NO (nitric oxide) and NO_2 (nitrogen dioxide). The predominate specie is NO since the furnace residence time is too short to oxidize significant amounts of NO to NO_2. The Thermal NOx formation is rate controlled and can be simplistically expressed by the Zeldovich Equation below:

$$[NO] = k_1 \exp\{(-k_2/T)\ [N_2]\ [O_2]^{1/2}\ t\} \qquad (2\text{-}1)$$

where:

$[\ ]$ = mole fraction,

k_1, k_2 = kinetic constants,

T = temperature,

t = time.

From this equation, it can be seen that time and temperature play an important role in the formation of thermal NOx as well as the availability of excess oxygen. At temperatures below 2800 to 3200°F the formation rate is low and only small amounts of NO are formed. Due to the rapid heat loss to the furnace walls in most boilers, the time at the peak formation temperature in utility furnaces is small. As a consequence, only small amounts (compared to the maximum potential) of NO are formed. In most liquid and gaseous fueled utility boilers, the maximum level of NO formed is from 0.05 to 0.15 percent of the total effluent. In utility boilers, the NO_2 emission level is generally from 3 to 5 percent of the total NOx emissions (0.0015 to 0.0075 % of the total effluent [Reference 2-1]).

Nitrogen oxides are also formed during the pyrolysis of the nitrogen within the fuel itself which is termed "Fuel NOx Formation". The precise mechanism of this Fuel NOx Formation is not known. Laboratory investigations of the Fuel NOx formation in coal have provided some insight into the relative contribution of the Fuel and Thermal NOx formation with this solid fuel. To a lesser extent, similar studies have also shown the impact of fuel bound nitrogen on the resultant NO formation when oil fuels are burned. In general, the fuel nitrogen content of coals is three to four times that of fuel oils. The contribution of the fuel bound nitrogen to the total NO formation in coals has been shown to be between 50 to 80 percent with the remaining NO in the form of Thermal NOx. With the oils burned by most utilities, the fuel bound nitrogen contribution to the total NO formation is in the order of 20 to 30 percent. Since natural gas does not have appreciable amounts of chemically bound nitrogen, the Fuel NOx contribution from this fuel is zero - all of the NO formation is Thermal NOx.

Due to the high combustibility of natural gas, the flames in uncontrolled boilers are relatively short and the NO is formed very near the burner. This allows very little loss of heat to the furnace walls before most of the NO is formed. For this reason, the NO levels are relatively high and are only influenced by other parameters such as flame quenching from recirculated gases from the cooler furnace walls to a relatively small degree. In addition, since natural gas flames do not radiate heat as well as liquid and solid fuels, only small amounts of heat are radiated to the furnace water walls during the high temperature portion of the combustion where NO is formed at high rates. These factors contribute to repeatability of NOx emissions levels from uncontrolled natural gas-fired utility boilers.

Liquid fuels used in utility boilers are also highly combustible but to a lesser extent than for gaseous fuels. Prior to combustion, the liquid fuel must first be vaporized which takes a finite period of time and consequently extends the flame away from the burner into the

furnace heat absorption zone. The increased flame length allows more time for recirculated gases to be cooled by the furnace walls before re-entrainment into the flame thereby potentially lowering the peak flame temperature. The increased radiant properties of the flame also allows some portion of the heat generated during combustion to be lost to the furnace walls thus also potentially lowering the peak combustion temperature. Depending upon the fuel nitrogen content of the fuel oil and boiler design features, the uncontrolled oil-fired NO emissions can either be higher or lower than that for gaseous fuels on the same boiler. The oil-fired NO emissions may range between ± 50 percent of the gas-fired NO emissions. The oil-fired NO emissions exhibit similar repeatable characteristics as do natural gas-fired no emission characteristics.

2.2 Alternate NOx Monitoring Method

The fact that, in general, the NO emissions from natural gas-fired and oil-fired utility boilers are repeatable suggests that a conservative determination of the total annual NOx emissions can be calculated based only upon the gas-and oil-fired NO emission characteristics and load history of the boiler. The basis for this conservative determination and the procedures are discussed below.

2.2.1 Basis for NOx Alternate Monitoring Method

As is evident from the Zeldovich Equation (Equation 3-1), excess oxygen availability affects the final NO emission level - the higher the excess oxygen level the higher the NO emissions. Consequently the NOx versus load characteristics of a particular boiler are dependent upon the operating excess oxygen level. Most gas-and oil fired utility boilers operate within a narrow excess oxygen band at a given load setting. This O_2 band is generally in the order of one percentage point wide (e.g., 2 to 3% excess oxygen) at high loads and potentially as much as two percentage points wide at low load. This narrow band is generally dictated by boiler efficiency considerations at high loads and steam temperature capabilities at low load conditions. On the average, at high loads the NO emission sensitivity to excess oxygen may be as much as 5% NO per percent O_2 while at low load the sensitivity is generally reduced to levels in the range of 2% NO per percent O_2. Given the excess oxygen excursions generally experienced from high to low loads, the maximum level of NO would be in the order of five percent above normal at the high load (for a +0.5 % O_2 excursion) and four percent at the low loads (for a +1.0 % O_2 excursion). Conservatively, this would mean a maximum bias of five percent over the load range if NO versus load characterizations were established irrespective of excess oxygen level.

The proposed alternate NOx monitoring method would utilize NOx versus load characteristics determined at specified intervals to establish the maximum potential NOx levels at any given load. This would be based upon the maximum operating excess oxygen level likely to be experienced on the boiler to provide conservative determinations

of the NO emissions. Figure 2-1 illustrates the type of characterizations that would likely result for both gas and oil firing. These types of characteristic curves for gas and oil would be used inconjunction with the average load over a specified time period (presumably one hour) to calculate the average emission level over that particular period of time. The average load over the time period would be calculated from the difference between the megawatt-hour meter readings at the beginning and end of the measurement period. At the end of any given time period the NOx emission level would be given by:

$$NO = K * f(MWH/T) \qquad (2\text{-}2)$$

where:

NO = Average measurement period NO emissions

K = Constant

f( ) = Functional relationship

MWH = Average megawatt-hours

T = Averaging time

The functional relationship of NOx versus load is derived from data similar to that presented in Figure 2-1 for each fuel.

The average emission level over any reporting period composed of a number of measurement periods would be given by:

$$NO_{Ave} = \frac{\int_{t_0}^{t_T} NO_t \, dt}{(t_T - t_0)} \qquad (2\text{-}3)$$

where:

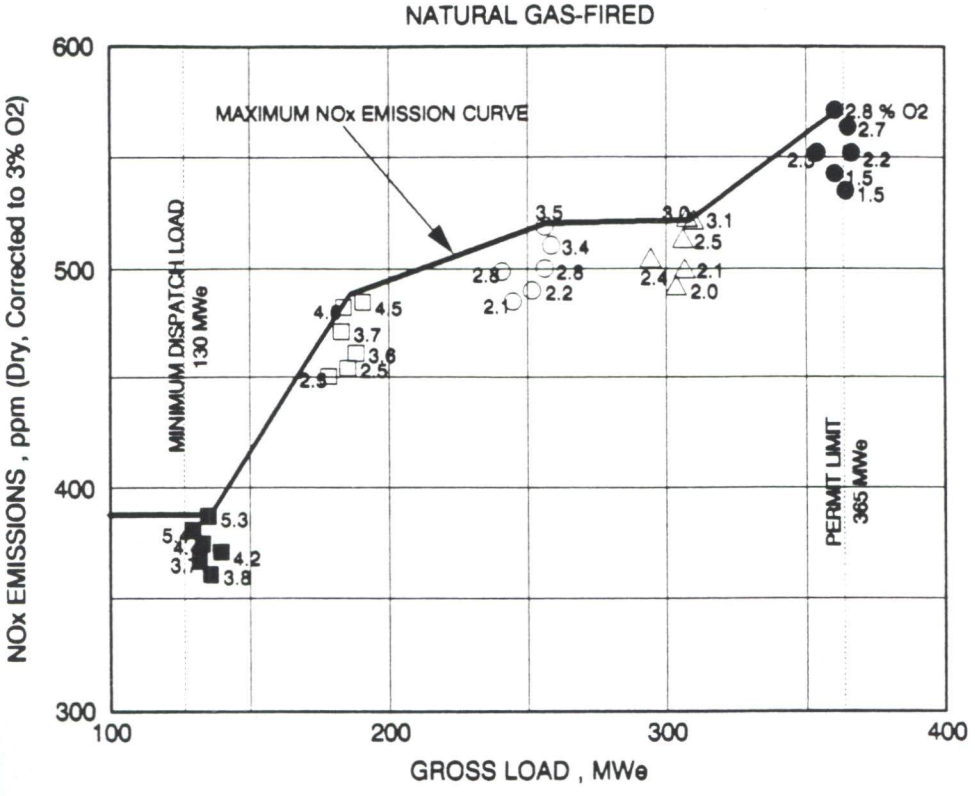
NO_{Ave} = Average NO over the reporting period

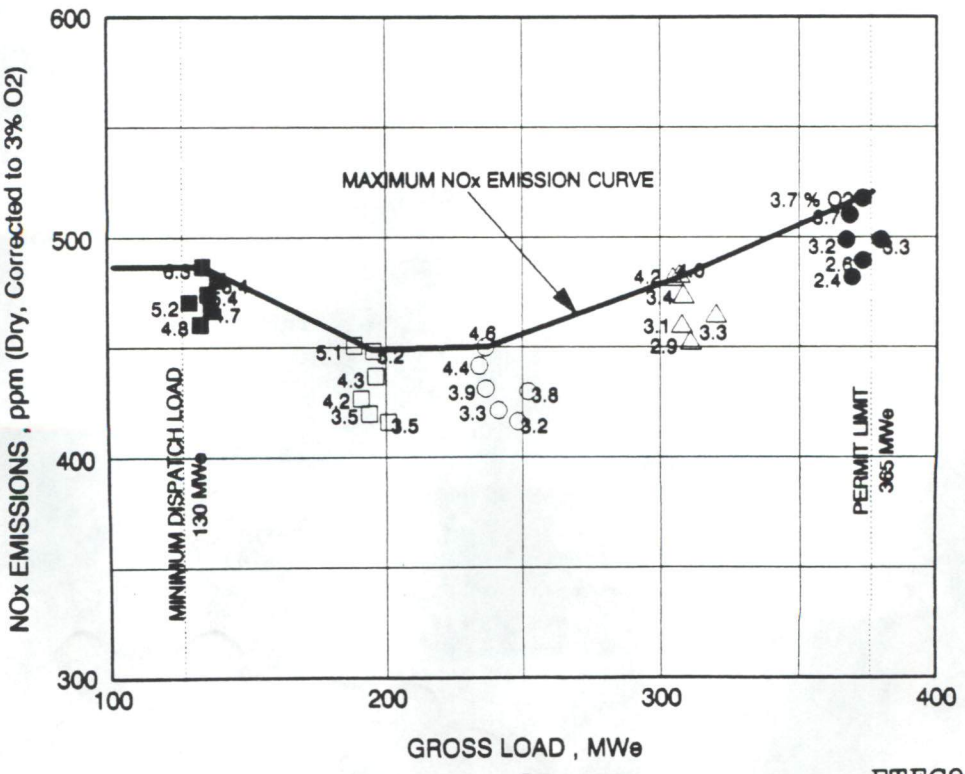
NO_t = NO emission level at time t

t_T = time at the end of reporting period

t_o = time at the beginning of reporting period

FIGURE 2-1 EXAMPLE MAXIMUM NOx CHARACTERIZATION CURVE





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Since watt-hour meter readings are frequently recorded by the boiler operator on or near the Clock Hour, this equation allows for non-uniform measuring time periods. If the watt-hour readings are automatically recorded, the time periods would be uniform.

2.2.2 NOx Monitoring Procedure

The critical characterizations required to obtain the conservative determination of the annual NOx emissions are the NOx versus load curves for both gas and oil fuels. Several measurements must be made to establish these characteristic curves - NOx in ppm, excess oxygen in percent and load in megawatts (or watts). The following describes the instrumentation required, and the procedure for establishing the maximum NOx emission characteristic curves.

Instrumentation

The nitric oxide (NO) measurement method should be the chemiluminescence instrumental method. To insure that NOx characterizations are consistent from one annual period to another, monitoring procedures during these characterizations should meet standards established by EPA for Method 7E - Determination of Nitrogen Oxides Emissions From Stationary Sources (Instrumental Analysis Procedure). Other comparable method(s) approved by EPA could also be used. Calibration of the NO instrument should be accomplished utilizing Protocol NO gases.

The measurement of excess oxygen (O_2) should be accomplished utilizing the plant O_2 instrument or other instrumental methods comparable in accuracy to the plant instrumentation. Acceptable measurement methods are electrochemical cell and paramagnetic or other methods approved by EPA. Calibration of the O_2 instrument should be made using high quality O_2 gases covering the normal range of O_2 expected.

Megawatt-hours should be measured utilizing plant instrumentation. The megawatt-hour meter should be calibrated to be within the accuracy specifications required for normal utility recording purposes.

NOx Versus Load Characterization

Both natural gas-fired and oil-fired NOx characterizations should be made at a minimum of five, approximately equally spaced, load points which should include loads ranging from 98 percent of the Maximum Continuous Rating (MCR) or the maximum permitted load and the normal System Dispatch minimum operating load. The MCR load should be established based upon the manufacturer's contractual specifications provided at the time of commercialization of the boiler. Where boilers are Permitted for operation within a state or local jurisdiction, the maximum load should be that load specified in the

Permit. The minimum System Dispatch operating load can be established from operating records for the past two consecutive years or based upon other suitable alternate records or boiler specifications.

At each of the five NOx characterization load points the NOx (corrected to 3 percent O_2) should be determined over the normal excess oxygen range. This range can be established based upon previous operating data. At least three excess oxygen test points should be characterized at each load point - maximum excess O_2, nominal excess O_2 and minimum O_2. At least two repetitions of the NOx measurement should be made for each of the three O_2 points. At each load point, the unit should be stabilized for a minimum of one hour prior to commencing O_2 characterization. At each O_2 test point, the O_2 should be recorded for a period of at least 20 minutes at five minute intervals and reported as the average of all readings during this period.

The NOx characterization should be tabulated listing the time of the test, duration, gross load, excess oxygen, uncorrected NOx (at actual excess oxygen level), corrected NOx (corrected to 3% O_2) and other pertinent data that may be used for determination of the maximum NOx emission curve. The results of these characterizations should also be presented in graphic form with NOx as the dependent variable and load as the independent variable as illustrated in Figure 3-1. Four (or more where appropriate) straight line segments should be constructed between the maximum measured NOx emission points for the five load points as shown in Figure 3-1. This upper bound of the NO data for each fuel would be used as the NOx characteristic curve for the subsequent annual period of monitoring.

The accuracy of the NOx emission determination is predicated upon obtaining representative NOx versus load characterizations at the maximum expected excess oxygen level. Based upon the repeatability of the NOx characteristics, a once per year characterization should be sufficient to maintain the level of accuracy required. The NOx characterizations for the reporting year should be completed no later than January 31st of the reporting year in order to be used in First Quarter Reporting requirements and/or End of Year Adjustments (discussed below). The current reporting year characterizations should not commence earlier than two months prior to the beginning of the reporting year. More frequent characterizations may be required if the boiler undergoes major modifications or if a significant change in the operational mode is instituted prior to the annual characterization.

Hourly Average NOx Emission Determination

The hourly average emission (lb/MMBtu) would be calculated utilizing Equation 3-4 below which is a form of Equation 3-2 described above.

$$NO_t = k_1 * k_2 * f\{(MWH_t - MWH_{t-1})\} / [t - (t-1)] \qquad (2\text{-}4)$$

where:

NO_t = NO emissions at time t, lb/MMBtu

k_1 = EPA C-factor, 1.192×10^{-7} lb/(dscf per ppm)

k_2 = EPA F-factor, 8740 dscf/MMBtu

$f\{\ \}$ = functional relationship of NOx versus Load, (ppm)

MWH_t = megawatt-hour meter reading at time t, MWH

MWH_{t-1} = megawatt-hour meter reading at time t-1, MWH

t = time at end of time period, hrs:min

t-1 = time at beginning of time period, hrs:min

The constants k_1 and k_2 are used to convert from the measured NO in ppm to the required reporting units of lb/MMBtu.

The NOx characteristic curve f{ } should be the maximum emission (lb/MMBtu) curve determined under NOx Versus Load Characterization described above. During hourly periods when gas fuel is burned the gas fuel NOx Versus Load Characterization is used to estimate the maximum emission level. During periods when oil fuel is burned, the oil fuel NOx Versus Load Characterization is used. During periods when both fuels are burned either simultaneously or separately during portions of the averaging period, the NOx Versus Load Characterization (either gas or oil fuel curve) that results in the highest emission level will be used to provide conservative emission estimates. The Megawatt-hour measurements and the time readings are those obtained from the operator hourly reporting log or from automated recording devices where available.

Quarterly Average Emission Determination

The Quarterly Average Emission (lb/MMBtu) would be calculated utilizing Equation 3-5 which is a form of Equation 3-3 described above.

$$NO_{Ave} = \frac{\sum_{i=1}^{T} \{NO_i * (t_i - t_{i-1})\}}{(t_T - t_0)} \qquad (2\text{-}5)$$

where:

NO_{Ave} = Average NO emissions over Reporting period, lb/MMBtu

T = total Quarterly hourly measurement time periods

i = ith hourly measurement time period

NO_i = NO emission level during period i, lb/MMBtu

t_i = time at end of measurement period i, hr:min

t_{i-1} = time at beginning of measurement period, hr:min

t_T = time at the end of reporting period, day:hr:min

t_o = time at the beginning of reporting period, day:hr:min

End of Year Adjustments

The Annual Average NOx Emission (AANE) could be determined using Equation 3-5 and the NOx Characteristic curves f{ } (for gas and oil fuels) for the current reporting year and compared to the AANE utilizing the NOx characteristic curves determined at year end for the subsequent reporting year. Both AANE values could be reported in the year end emission report. If the resulting emission levels are significantly different, the average of these two estimations could be used as representative of the annual average NOx emission level.

2.3 NOx Alternate Monitoring Conclusions

Based upon the fact that the procedures described in the preceding sections are based upon the Maximum NOx emissions that are expected on either gas or oil fuels, the estimation of the annual average NOx emission level (lb/MMBtu) will be conservative. This procedure will always result in NOx emission levels that are greater than the actual emissions due to the fact that the boiler will not continuously operate at the maximum excess oxygen level. The majority of time, the boilers will operate at or near the normal excess oxygen level and for some periods of time at the minimum excess oxygen level. Based upon the normal NOx sensitivity for the typical excess oxygen excursions it would be expected that the annual average NOx emission level would be , at most, in the order of five percent high using this Alternate NOx monitoring method.

Another aspect of the alternate NOx procedure that results in conservatively high NOx emissions is due to the fact that the

procedure uses the highest NOx emission characteristic for either fuel when both are burned during a measurement period. In the actual case, the NOx emissions would be somewhere in between the characteristic curves for the two fuels. The conservatism would be dependent upon the amount of differences between the two NOx curves, but in any case the reported NOx emissions would always be greater than the actual emissions.

Minor changes in the annually determined NOx characteristics over the year for both fuels are taken into account by utilizing the of the End of Year Adjustments. This procedure also adds conservatism to the estimation of the annual NOx emission level.

These three aspects of the proposed Alternate NOx Monitoring Methods all result in the reported NOx emission levels being conservatively high.

3.0 REFERENCES

3-1 Compilation of Air Pollutant Emission Factors, U. S. Environmental Protection Agency, Publication No. AP-42, September 1986.

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and compliance certifications. Use of these forms or the computerized permitting system will help to ensure nationally uniform implementation of the permitting requirements, and to prevent the increased costs that would be associated with the imposition by States of additional Acid Rain permitting requirements. The Agency believes that this requirement will facilitate the allowance market because all sources, no matter where they are located, will be subject to the same requirements.

The Agency requests comments on these criteria for State program approval.

Subpart J - Permit Revisions

Subpart J specifies the procedures that would apply for revising Acid Rain permits. The rule proposes that permit revisions would become effective upon approval in accordance with the procedures specified in Subpart J. This is to ensure that no proposed revision could be used to insulate a source from the obligation to comply with a permitted requirement, and to provide clarity regarding what applies to a source at any given point in time.

Generally, the proposed rule tracks the permit revision requirements in proposed Section 70.7, which would apply to State permitting programs under Title V of the Act and 40 CFR Part 70. The Title V rules propose three types of permit revisions: permit modifications, minor permit amendments, and administrative permit amendments. Subpart J of today's proposal specifies how various types of changes to Acid Rain permits would fall into the 40 CFR Part 70 categories of revisions. It also proposes ~~two~~ additional categories of ~~revision, procedures, fast-track modifications and~~ automatic permit amendments.

Prohibited Revisions. The rule ensures that certain Acid Rain permit provisions cannot be modified. For example, notwithstanding any changes a source makes in its method of compliance, each unit must hold enough allowances in its Allowance Tracking System account to cover its SO_2 emissions for the year. This requirement cannot be revised. Other standard provisions would similarly not be subject to any possible revision.

Modifications. Under 40 CFR Part 70 permit modifications would include any proposed revision to a permit to address a change at the source that would constitute a modification under any provision of Title I of the Act. Since the Acid Rain permit provisions cannot alter or affect requirements under other provisions of the Act, (including Title I), that category of permit modifications is inappropriate to the Acid Rain program.

a variant allowing

(See discussion below.)[9] Modifications under Title V and 40 CFR Part 70 would also include almost any relaxation of a reporting requirement or a milestone in the schedule for compliance for a non-complying source. These categories of revisions clearly would apply to the Acid Rain program. Today's proposal specifies that, within the 40 CFR Part 70 structure, the Acid Rain program would apply permit modification procedures to changes such as the addition of a new compliance option that the source did not submit to the permitting authority with the initial permit application for review and comment during the permit issuance process, and that involves a unit at a source that was not previously affected and subject to the Acid Rain permit's requirements. The Agency also proposes to use the permit modification procedure (or the fast-track modifications procedure as discussed further below) for revisions to a previously approved compliance plan that involve units not previously governed by the plan.

reviewed Bund, where appropriate, public involvement.

The Acid Rain compliance option is a fundamental component of the permit. Certain changes in the compliance option, such as those described above, have significant implications for allowance allocations, on emissions levels, and sometimes, on unit coverage under the program. Thus, the Agency believes that certain significant changes to compliance options must not occur without adequate opportunity for public involvement. Where, however, a new or revised compliance option does not involve a unit not previously affected, for example a new reduced utilization plan relying on energy conservation measures where no compensating unit is designated, the permit modification procedure would not apply. This is because the Agency does not believe that such a revision would give rise to concerns of public interest that would warrant a full notice and comment procedure. This approach is consistent with the NPDES, RCRA, and UIC programs, all of which mandate an opportunity for public comment before incorporating major changes into the operating permit.

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[9]The concept of "modification" as used in an Acid Rain Program context is distinct from the use of the term in an NSR or NSPS context under Parts C or D or Section 111 in Title I of the Act. The Agency's proposed "WEPCO decision" [56 FR 27630, June 14, 1991], therefore, does not affect today's proposal. The revision of the modification definition for purposes of "WEPCO" concerns physical or operational changes to the facility, in particular, pollution control projects which could affect ambient air quality. Certain changes (pollution control projects) will be exempt from NSPS and NSR so long as they are "not less environmentally beneficial". A change in an Acid Rain compliance option may or may not involve a pollution control project. However, no such change would alter ambient program requirements applicable to the source.

In addition, Sections 72.300(e) and 72.301 provide that a State decision interpreting an Acid Rain program permit provision in a manner that effectively modifies or voids a program requirement would be deemed a proposed permit modification by operation of law. As with any proposed permit modification by the State during Phase II, such an interpretation would be subject to Agency review pursuant to Section 70.8 of the Title V rules. Under 40 CFR Part 70 public comment and Federal oversight, as required for original permit issuance, would be required for modifications except that such comment and oversight would cover only the proposed permit changes, rather than the unchanged activities at a source, appropriate ?

~~Fast-Track Modifications:~~ The Agency believes that an expedited procedure is ~~necessary~~ to allow for permit modifications in a manner that will provide sources with the flexibility to make needed changes in a timely manner. Without such a procedure sources would have to follow the more burdensome modification procedures ~~[redacted]~~ specified in 40 CFR Part 70. Today's proposal, therefore, includes a separate "fast-track" modification procedure, at Section 72.302, which could be used at the option of the source in lieu of the modification procedure of Section 72.301, for example, (1) where an affected source wishes to change its method of compliance with the Acid Rain program requirements to an Acid Rain compliance option under Subpart D which it did not submit for approval and comment during the permit issuance or reissuance process and which, in the absence of the fast-track procedure, would have to made pursuant to the modification procedure of Section 72.301; (2) for a change in a Phase I Extension, repowering extension, NO_x extension, NO_x averaging, or NO_x alternative emissions plan; or (3) for a change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program. As is noted above, these types of changes are fundamental to the Acid Rain program and would normally be subject to the permit modification process. The time and resources involved in the permit modification process set forth in 40 CFR Part 70 would, however, take away much of the source flexibility which the Acid Rain program was designed to ensure. Congress intended the Acid Rain program to promote least-cost planning through optional methods of compliance and an active allowance market. Requiring the affected source to go through a time- and resource-intensive process each time it wished to change its method of compliance would restrict much of the flexibility of the Acid Rain program. Sources should be able to revise their methods of compliance where the method originally chosen does not turn out to be cost-effective.

Balanced against this interest is the need to ~~have public [redacted]~~ ensure

providing appropriate review and public involvement for

that the source is held accountable for the requirements in its permit. The Agency is, therefore, proposing a fast-track modification procedure to avoid the excessive delays associated with the permit modification procedure proposed in 40 CFR Part 70, ~~while not sacrificing the need for public notice and comment on a substantial change to the permit.~~ The proposal includes two options for the fast-track modification procedure. The Agency requests comment on both.

In most cases a prudent source, uncertain of the most cost-effective method of compliance, will seek conditional approval of several compliance options in its permit application and compliance plan, ~~with a schedule by which it will decide which method(s) it will use.~~ The Agency encourages sources to do this. In this way, when the source notifies EPA of the compliance option it wishes to use, or that it wishes to switch methods, the permit could be revised through the administrative amendment procedure discussed below. (See, also Section 70.7(e)) ~~The Agency believes this approach is appropriate because the compliance option will have undergone public notice and comment during the permit issuance procedures.~~

Sources may not, however, always be able to predict all possible methods of compliance that they might need during the permit issuance process. A source may wish to change the method of compliance for a unit in the middle of the permit term.

Three approaches to fast-track modifications are offered. Under the first approach, the applicant would submit the proposed revision to EPA. EPA would then have 30 days to approve or disapprove it. If EPA proposed to approve the revision, actual notice would be sent to interested persons, i.e. all persons who (1) commented on the proposed permit, or (2) requested to be informed of any subsequent permit actions proposed to be taken concerning the source. (The second category of interested persons could get their names on a mailing list for notice of any subsequent permit actions, whether or not they had comments on the initial proposed permit.) Interested persons would have 15 days in which to raise substantive objections to the proposed fast-track modification. If no substantive objections were received, the modification would take effect. If substantive objections were received, the proposal would have to go through the permit modification procedure, including general public notice, of 40 CFR Part 70. Objections would be evaluated by the Agency, using the criteria in Section 72.77, to determine whether they were substantive.

Under the second approach to fast-track modifications, the permittee would give public notice of its proposed new compliance option through publication in a journal (or newspaper) of national and general circulation. The permittee would also give actual notice to each interested person, on or after the permittee submitted the proposed compliance option to the

Administrator. The notice would specify that all comments be submitted to the Administrator. The public would have 30 days to send comments to the Administrator. The Administrator would approve or disapprove the fast-track modification within 30 days after the end of the comment period.

EPA believes that either of these approaches would prove to be more expeditious than the permit modification procedures of 40 CFR Part 70. ~~without sacrificing the opportunity for public notice and comment.~~ The first approach is more streamlined than the second, so long as no substantive objections are raised. The second approach would be quicker if the public were to raise objections. EPA is considering whether to: (1) promulgate the permit modification procedure of 40 CFR Part 70 only, (2) choose one of the options for fast-track modifications, or (3) promulgate both fast-track modification options into regulation and allow the permittee discretion to choose which option to use. The Agency requests comment on these approaches.

Administrative Permit Amendments. The Agency also proposes to adopt, for purposes of the Acid Rain program, the administrative amendment procedures set forth at 40 CFR Part 70. An administrative permit amendment under 40 CFR Part 70 would be made by the permitting authority, ~~with no advance public notice or comment required.~~ Changes to a permit, such as corrections of typographical errors, changes in names, addresses, and phone numbers, a change which requires more frequent monitoring at a source, and in most cases a change in ownership or operational control at a source are included under the administrative amendments procedures of 40 CFR Part 70. Today's proposal would add to that list: changes such as the activation of a compliance option which was previously conditionally approved in the original permit application provided that the option is activated ~~within the time frame specified in the permit~~; and changes to the designated representative, so long as a new certificate of representation is submitted pursuant to Subpart B. The administrative permit amendment procedure would also be used to incorporate or revise a reduced utilization plan that does not involve a compensating unit, so long as the plan meets all the requirements specified in the regulations at Section 72.43, and changes to a substitution plan that does not result in a previously unaffected unit becoming affected.

The Agency also proposes that the administrative permit amendment procedure be used to terminate an Acid Rain compliance option as authorized by the regulations. This approach would, however, be subject to the limitations on terminating options applicable to Phase I Extensions and Repowering Extensions, as well as the limitations on de-designating substitution units in Section 72.41, and on de-designating compensating units in Section 72.43.

In addition, the administrative amendments procedures would apply to incorporate alternative monitoring systems approved under 40 CFR Part 75 of today's proposal, and excess emissions offset plans pursuant to Section 411 of the Act approved by the Administrator according to procedures specified in 40 CFR Part 77 of today's proposal into a permit. The procedures for these two categories of actions by the Administrator include public comment. ~~Further public comment would, therefore, be redundant~~.

EPA asks for comment on the scope of permit revisions appropriately made pursuant to the administrative amendments procedure.

Minor Permit Amendments. Under proposed 40 CFR Part 70 a minor permit amendment procedure is also authorized, to cover any proposed revision to a permit that is not a modification under Title I.[20] This procedure is primarily intended to provide sources with operating flexibility in their day-to-day operations. Because the Acid Rain program is an annual program which, by definition, provides ample flexibility with regard to variation in operating conditions throughout the year, EPA does not believe that this procedure would be necessary ~~or applicable~~ for most ~~of the~~ types of revisions that will be seen in Acid Rain program. ~~In addition, since State procedures for minor permit amendments may vary, this form of revision could undermine the overriding goal of the Acid Rain program of national consistency. Thus, it is important that all States follow the same procedures for Acid Rain permit revisions to ensure this consistency. The Agency particularly wishes to avoid situations where a change to an Acid Rain permit is treated as a minor permit amendment in one State, but not another. The Acid Rain program needs to ensure that sources are not penalized or benefitted based on the State in which they are located. Since States can develop their own procedures, the resource burden associated with minor permit amendments may vary from State to State.~~

~~The minor permit amendment process is not needed for utilities under the Acid Rain program~~. The changes that utilities might need to make rapidly generally would not involve any sort of notice or permit revision under the Acid Rain program. For example, operational changes such as fuel switching would not normally require any notice. The few types of changes that would need to be made rapidly and for which notice ~~is~~ might be

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[20] The source would be required to notify the permitting authority 7 calendar days before the change is to occur. The rule would require the change to comply with all applicable elements of the Act relevant to the source. Under this procedure, the permitting authority has 7 days to notify the source if the change is not acceptable as a minor amendment, and it is then treated as a modification.

required are covered under the administrative or automatic permit amendment procedures (e.g. end-of-year allowance transactions amend the permit automatically upon recordation with EPA). The changes that would necessitate a permit revision with significant input from the permitting authority are, under the Acid Rain program, all long-term changes. Thus, ~~Unlike in the Title V program,~~ a two month delay for approval of a new compliance option would not hinder the ability of sources to operate in a cost-effective manner. For example, a source may determine in the middle of the permit term that it is more cost-effective to make emissions reductions at a Phase II unit and to bring the Phase II unit in to Phase I as a substitution unit. Since allowances will be allocated on an annual basis, the source may specify whether the new allowance allocation is to be calculated retrospectively for that calendar year, or applied to the following calendar year. Any delay on the part of EPA in processing the revision (under the fast-track modification procedure, for example) would, therefore, not affect the source's ability to comply with the Act. ~~It is important to keep in mind that Title V generally and the Title V minor permit amendment process specifically is meant to address the needs of a much more~~ varied regulated community. The change in operations is not analogous to a small batch processor receiving an order for a chemical which must be manufactured within a week or two. Under the Acid Rain program, many changes can be made by a unit without the need to submit a new compliance option or to notify EPA, e.g. buying allowances to cover emissions, switching to low sulfur coal, and installing pollution control equipment (except as provided under an Acid Rain incentive program such as the repowering extension). The Agency, therefore, believes that the minor permit amendment process ~~is~~ not ~~applicable~~ to the Acid Rain program. Thus, EPA is proposing that no revisions to the Acid Rain portion of a permit would be processed under the minor permit amendment procedure. However, EPA requests comments on the need for a minor permit amendment provision and, specifically requests comments on the types of changes that would best be covered through minor permit amendments.

EPA believes that a

Delete ?

Automatic Permit Amendments. Today's proposal also provides that allowance transactions to or from a unit's Allowance Tracking System compliance subaccount that are properly recorded with EPA would automatically amend the permit. Title IV of the Act specifies that allowance transactions be treated differently from most permit revisions. The proposal reflects this statutory requirement. Allowance transactions are incorporated into permits as automatic amendments upon recordation by the Administrator. A detailed discussion of allowance transaction recordation can be found in the 40 CFR Part 73 preamble.

Subpart E - Compliance Certification

Compliance certifications are a fundamental element of the Acid Rain program's implementation strategy. The term "compliance certification" is defined in today's proposal as a

report signed and verified by the designated representative of the source's or unit's compliance or non-compliance with applicable requirements. The statutory authority for this requirement can be found in Section 114(a) of the Act (as amended by Section 702 of Act Amendments of 1990), which requires that the Administrator promulgate enhanced monitoring and compliance certification regulations, and in Section 504(c) in Title V of the Act, which requires that compliance certification requirements be included in each source's operating permit.

The Agency believes that heavy reliance on compliance certifications in the Acid Rain program will greatly increase flexibility, reduce the burden on sources of demonstrating compliance while maintaining the Agency's ability to ensure program accountability. They will also provide a helpful vehicle for resolving misunderstandings concerning applicable requirements before there has been a violation. This feature which should greatly increase program certainty for sources.

The strategy of relying heavily on certifications evidences a dramatic departure from the methods traditionally used to determine compliance, i.e. on-site inspections and source-specific investigatory letters requiring the collection and submission of emissions data and operational reports. The Agency proposes that every Acid Rain program submittal be certified as to its truth and accuracy by the designated representative. As is discussed in Subpart B, only the designated representative can submit compliance certifications.

Compliance certifications are categorized in today's proposal according to frequency of submission, such as quarterly or annual. The proposal specifies the contents and submission dates for these certifications and reports. The submission deadlines are consistent with the Agency's proposal today at 40 CFR Part 73, specifying an end of year allowance transfer deadline for sources to consolidate data and conform their allowance accounts, and the emissions data reporting requirements of 40 CFR Part 75.

Some compliance certifications would be submitted on an irregular schedule to provide the Agency and the permitting authority with notice of an operational change. The proposal also requires the designated representative of an affected unit employing one or more Acid Rain compliance option to include in the annual, quarterly, and other reports, the compliance certifications specified in the sections of the regulation for the relevant compliance option.

One data requirement that the Agency believes is an essential program element during Phase I is heat input and generation information. This information is necessary to ensure compliance with the reduced utilization requirements of the program (addressed in today's preamble discussion of Section 72.43 and Subpart C), and to allow sources the flexibility to

pursue their normal dispatching operations while ensuring that SO_2 emissions are accounted for in accordance with Section 403(d)(1) and (2) of the Act. The annual compliance certification for each Phase I unit would provide that if the unit has reduced utilization below its baseline, the designated representative must make one or more of several demonstrations to account for the SO_2 emissions that would have resulted from load shifts. The annual compliance certification would also require the designated representative to certify whether any reductions in utilization caused the unit to be subject to the planning requirements for reduced utilization in Section 72.43 of Subpart D.

Need for Information. Some information proposed to be required in annual compliance certifications is information that the Agency could obtain from other sources. This proposal contemplates, however, that compliance certifications be self-contained documents to the extent feasible. First, this will facilitate more expeditious review of a source's compliance status. In addition, the Agency believes that requiring the designated representative to report this information and certify emissions totals will provide an added verification of the data, and minimize the opportunity for disputes concerning the compliance status for each unit. The Agency requests comment on the scope of the information required to be included in the annual compliance certification.

Subpart L - Phase I Extension Early Ranking Procedures

Subpart L would provide the procedures for early ranking of Phase I Extension plans submitted under Section 72.42 of today's proposal. Subpart L addresses two concerns: (1) the statutory mandate in Section 404(d)(3) of the Act that submissions for Phase I Extensions be considered by the Administrator "in order of receipt", and (2) the need of the regulated community to know as early as possible whether they will be eligible for Phase I Extension allowances. Because of the economic benefits a source would derive from a Phase I Extension, some estimates indicate that the Phase I Extension allowance reserve of up to 3.5 million tons, mandated by Section 404(a)(2) of the Act, may be oversubscribed. Many sources can, therefore, be expected to apply for Phase I Extension allowances in a short period of time, making it difficult to determine the "order of receipt" of a proposed Phase I Extension plan submitted under Section 72.42 by relying exclusively on postal delivery services.

The Agency is, thus, proposing an Early Ranking procedure for determining the order in which to act on Phase I Extension applications. The Agency proposes to use a voice-mail telephone queuing procedure followed by a written Phase I Extension Early Ranking application submission mailed not later than midnight of

the same business day of the phone queue. The "order of receipt" established by the Early Ranking procedure would be conditional. In particular, it would be conditioned on timely submission by the designated representative for each applicant, in accordance with the procedures proposed in Subpart C and Section 72.42 of Subpart D of today's proposal, of a complete and approvable permit application and proposed compliance plan by the Phase I permit application deadline of February 15, 1993 specified in Section 408 of the Act.

Industry's Interest in an Accelerated Procedure. Information available to EPA indicates that it takes three years to design, construct, and install qualifying Phase I Extension control technology (i.e. 90% controls). The Agency believes that the Early Ranking procedure proposed today is necessary to provide sources considering installing such controls with a reasonable idea of whether they will be eligible for Phase I Extension allowances, and to allow utilities enough time to install the qualifying Phase I technology before January 1, 1997. (See preamble discussion of Section 72.42 of Subpart D, of today's proposal for a more detailed discussion of Section 404(d) of the Act.)

Overview. Subpart L presents a voice-mail phone queuing procedure which sources seeking a Phase I Extension may use for obtaining an early ranking.[21] Subpart L also describes procedures for EPA action on Early Ranking applications. Currently available voice-mail systems can receive hundreds of calls within a short period of time, and rank them in order of incoming calls by nanoseconds. The Agency proposes this approach because it is consistent with the statutory language of "order of receipt", and it affords an expeditious minimally burdensome way for giving applicants critical information regarding their eligibility for extension allowances at an early stage in the program.

As described in Section 72.500, Subpart L applies only during Phase I, and only to existing affected units for which a Phase I Extension is sought pursuant to Section 72.42 of today's proposal. Consistent with other provisions of Part 72, the designated representative(s) for the unit(s) in a proposed Phase I Extension plan would be the sole person(s) with authority to participate in the Early Ranking procedure under this subpart.

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[21] Sources that did not wish to participate in the Early Ranking procedure could wait until submitting their permit application, as provided in Subpart C of today's proposal, to submit a proposed Phase I Extension plan. The proposed plan would, however, have to be disapproved if the extension allowance reserve were oversubscribed.

Under today's proposal, the designated representative for each affected unit that would be governed by the Section 72.42 Phase I Extension plan would submit a certificate of representation. EPA proposes to issue a designated representative identification number and a secure PIN number to each designated representative within 30 days of receipt of a certificate of representation. (See, Subpart B of today's proposal). These identification numbers are required to participate in the Early Ranking phone queuing procedure. The notice would include instructions for the designated representative to follow in order to participate in the phone queuing procedure. These would include the phone number the designated representative must call, the earliest date and time to call, instructions on how to enter information into the voice-mail system, and instructions and forms for the follow-up mailing. EPA plans to run a phone queuing demonstration test during the proposal period to test this approach. Anyone interested in participating in the demonstration should write to the U.S. EPA, Acid Rain Division, (ANR-445), Attn: Chief, Permits and Technologies Section.

Section 72.502 describes the Administrator's action on Early Ranking applications. Following the ranking, allowances would be conditionally awarded by the Administrator based on the order of each Early Ranking application as established by the phone queuing procedure, until all applications were acted on or until the reserve appeared to be oversubscribed.

Because EPA recognizes the need for applicants to know their conditional ranking as soon as possible, Subpart L proposes that EPA would notify applicants within 15 to 30 days after the conditional ranking is established through the phone queuing procedure. Allowance awards would be calculated based on the formula described in Section 72.42. The awards would be conditional in several respects. First, they would be subject to an applicant's meeting the full requirements for submitting complete permit applications and Phase I Extension plans that are set forth in Subpart D, Section 72.42 and Subpart C of today's proposal. The Administrator's action on Early Ranking applications would also be conditional subject to subsequent corrections to the information contained in the application and to the results of challenges to the rule, if any are brought. Moreover, if Subpart L is promulgated in final in advance of the rest of the core rules (Parts 72, 73 and 75), the Administrator's action on Early Ranking applications would be subject to the designated representative modifying the application, as necessary, to conform to the Part 72 rule as finally promulgated. Two provisions which would be promulgated at Part 73 after the Early Ranking procedure is implemented, and which could significantly affect the allowance awards for each Phase I Extension plan, are the procedures for annualizing Federally

enforceable allowable emissions limitations, and the calculation of 1988 and 1989 emissions for each unit.

The ranking provided for in Subpart L would, therefore, not constitute either an approval of a proposed Phase I Extension plan or an award of Phase I Extension allowances. Thus, the ranking provided for by Subpart L would be presumptive, and conditional on the Administrator's review of, and action on, a complete Phase I Extension plan and approvable and timely permit application pursuant to Subpart C and Section 72.42. Likewise, Phase I Extension allowances would be awarded pursuant to the ranking procedure on a conditional basis only. The awards would be subject to the timely submission of the permit application and compliance plan, and to yearly demonstrations that the qualifying Phase I control technology for the control unit and the source has achieved 90% removal of sulfur dioxide (See, Section 72.42). Actual approval of Phase I Extension plans and awards of Phase I Extension allowances would be made pursuant to the provisions of Section 72.42. The conditional ranking would, however, give applicants greater certainty regarding the approximate distribution of the Phase I Extension allowance reserve, assuming all subsequently required submissions and steps are achieved.

Other Approaches Considered for Determining "Order of Receipt". 1. Modified Phone Queue Approach. Under another approach the Agency is considering the designated representative would submit an Early Ranking application to EPA by certified mail when he or she submits the certificate of representation. EPA would begin accepting applications 15 days after the day the rule is promulgated in final in the FEDERAL REGISTER. Once an Early Ranking application was received, EPA would notify the applicant within 30 days whether the application was complete. An application would not be deemed to have been complete or received unless and until the certificate of representation required by Subpart B was received by the Administrator.

All complete Early Ranking applications received by EPA on a given day would be considered to have been received at the same time. For applications received on a particular day that did not result in the Phase I Extension allowance reserve being oversubscribed, the notification of receipt would specify a conditional award of allowances. If, however, the applications received on a given day resulted in an apparent oversubscription of the Phase I Extension allowance reserve, a phone queuing procedure would be used to determine the "order of receipt" for the tied applications.

Beginning on the day of apparent oversubscription, for each application received on a day when more than one application was received, the Administrator's notification of completeness would specify that a phone queuing procedure would be used to determine the application's "order of receipt" for the tied applications. The notification would indicate the date and time (not earlier

than 30 days and not later than 60 days after the date of the apparent oversubscription) when the phone queuing procedure would be carried out. In addition, the Administrator would issue with the notice a secure application identifier number for use during the phone queuing procedure. The period between the day of oversubscription and the day on which the phone queuing for that day was scheduled to take place, would provide each applicant an opportunity to decide whether to withdraw the application and proceed with other compliance options. Applicants would be able to elect not to participate in the phone queuing.

2. Lottery. Another option considered by the Agency is a chance drawing or lottery approach. As with the modified phone queuing approach, under this approach, the designated representatives for all applications received on the same day beginning on the day of oversubscription would be notified of the tie, and each applicant would be issued an application identifier. The designated representatives would, thereafter, have 30 days to decide whether to participate in a chance drawing. Designated representatives that did not notify EPA in writing within 30 days to proceed with the chance drawing would be deemed to have withdrawn their applications. The chance drawing, using the application identifier, would be used to randomly establish the individual ranking of each tied application for which an election to participate was made. The designated representatives for participating applicants could be "present" at the drawing at their option.

3. Date Stamp. Under another approach, under consideration for determining the "order of receipt" of Phase I Extension Early Ranking applications, applications would have to be submitted by certified mail. These would be date/time stamped by EPA in the order they were received at the location of the date stamp machine. The EPA time clock would determine each application's "order of receipt".

4. Stand-in-Line. The Agency considered and is rejecting a stand-in-line approach to determining "order of receipt". Under this approach, applicants would have to deliver Early Ranking applications in person, and the rule would specify a date and time for applicants to begin submitting their applications. This approach, however, presented major logistical problems for the applicants who would be required to wait in line, and for the Agency.

5. Pro Rata. Another approach that was proposed to EPA, but is rejected by the Agency, was a pro rata distribution of reserve allowances. As in the modified phone queue and lottery approaches, this option would have provided for a window of submission that was one day long, so that any application received during a given day would be considered to have been received at the same time. The pro rata approach is also similar to the modified phone queue and lottery approaches discussed

above in that, beginning on the day the applications received oversubscribed the reserve, a 30-day cooling-off period would be observed during which any applicant could choose to withdraw their application. The pro rata approach differs from the modified phone queue and lottery approaches, however, in that after the 30-day cooling-off period, the Administrator would award any allowances remaining in the reserve on a pro rata basis to the remaining applicants.

In considering this option, the Agency recognized that distributing reserve allowances pro rata to more applicants, rather than giving the full amount requested to fewer applicants, might potentially encourage the installation of more control technology. However, the allocation scheme ultimately adopted by Congress in Section 404(d) -- including the requirement that applications be acted on and allowance awards made "in order of receipt"--is very specific in requiring a sequential distribution of allowances from the reserve, rather than a distribution of a share of allowances to all applicants. In addition, a pro rata distribution would be substantially more time consuming than the approach proposed today. Nor would today's proposal preclude side-bar pro rata agreements between applicants, should utilities wish to pursue such arrangements. EPA would have no involvement, however, with such agreements.

Early Rulemaking. EPA is considering accelerating final promulgation of portions of today's Part 72 proposed rulemaking in order to implement the Early Ranking procedures as soon as possible. The portions of today's proposal which would be included in an accelerated final package include Subpart L, Subpart A (general provisions), Subpart B (designated representative certification procedures), and Section 72.42 of Subpart D. In the event comment on those subparts is favorable, the Agency would be in a better position to move forward with an accelerated rulemaking and early implementation of the Early Ranking procedure. Significant adverse comment on these provisions would make an early rulemaking less feasible.

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October 15, 1991

BY HAND

Mr. Larry Kertcher
U.S. Environmental Protection Agency
Acid Rain Division, ANR - 445
401 M Street, S.W.
Washington, DC 20460

Sufficiency of EPA's Draft Regulatory Impact Analysis

Dear Mr. Kertcher:

In developing a final proposal for the § 412 monitoring program, the Agency is obligated under Executive Order (E.O.) 12291 to examine alternative regulatory approaches and the costs and benefits of its proposal and those alternatives. As the enclosed paper explains, we believe that the Agency's draft Regulatory Impact Analysis written to satisfy E.O. 12291 is inadequate with regard to the monitoring regulations. Compliance with the requirements of E.O. 12291 will, in our view, lead the Agency to conclude that the stringent monitoring regulations under consideration would impose unnecessary costs without increasing the accuracy of annual SO_2 or NO_x emissions. If you have any questions about the enclosure, please feel free to call one of us.

Sincerely yours,

Henry V. Nickel
Mel S. Schulze

MSS/nbt
Enclosure

cc: James B. McRae, Jr.

October 15, 1991

Sufficiency of EPA's Regulatory Impact Analysis on Emission Monitoring under the Acid Rain Program -- Compliance with Executive Order 12291

When promulgating any new regulation, EPA is required by Executive Order 12291 ("EO 12291") to define the regulatory goals of the program, and to choose the alternative approaches to those goals that involve "the least net cost to society."[1/] In order to ensure compliance with this and other general requirements of EO 12291, the Agency must prepare a Regulatory Impact Analysis ("RIA"), including a description of the potential costs and benefits of the proposed regulations, in conjunction with any major proposed rule.[2/]

While a primary purpose of EO 12291 is to ensure that the Agency carefully evaluates the costs and benefits of its proposal, EO 12291 also clearly requires an agency to identify and evaluate alternative proposals. Specifically, EO 12291 requires that the agency include in the RIA a description and analysis of all those alternative approaches that could "substantially achieve the same regulatory goal at lower cost."[3/] In the event that the Agency identifies, but does not adopt, such an alternative, EO 12291 requires that the Agency

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1/ Executive Order 12291 (February 17, 1981) (hereinafter EO 12291), Section 2(d). See Section 2 for a full list of the general requirements.

2/ EO 12291, Sections 3(a), (d)(1) and (2).

3/ EO 12291, Section 3(d)(4) (emphasis added).

provide a legal reason why that alternative could not be adopted.[4/]

In June, EPA submitted a draft RIA to the Office of Management and Budget (OMB) to support its draft proposal for regulations to govern emission monitoring under the new Acid Rain Program (Title IV of the Clean Air Act Amendments of 1990).[5/] In an attempt to comply with EO 12291, EPA's RIA focused on estimating and comparing the costs of monitoring in the "absence of regulations" to the costs under several alternative regulatory approaches.[6/] For the "absent regulations" case, EPA assumed that all sources would be required by statute to install and operate a continuous emission monitoring system (CEMS), at a cost to industry of $2.225 billion,[7/] but that no CEMS performance standards or data reporting requirements would be imposed by regulation. For the alternative approaches, EPA estimated the costs/cost savings associated with several different regulatory requirements and exceptions.

4/ EO 12291, Section 3(d)(4).

5/ EPA's RIA actually addresses the entire package of regulations to be proposed by the Agency for implementation of Title IV. This paper, however, examines only those portions of the RIA that address emission monitoring requirements.

6/ See Regulatory Impact Analysis of the Proposed Acid Rain Implementation Regulations, Prepared by ICF Incorporated, EPA Contract 68-DO-0102, June 20, 1991 ("RIA"), pp. 4-15 to 4-26.

7/ All cost figures reported here refer to the present discounted value for the period 1993-2010.

As its first alternative ("Option 1"), EPA described a regulatory scheme under which all sources would be required to meet stringent CEMS performance standards and to report hourly CEMS data. No alternative monitoring systems or exceptions to CEMS would be allowed under this approach. Sources, however, would be allowed to choose their own format and manner of transmission for data reporting. EPA estimated the cost to industry of these regulations at almost $3 billion, or about $672 million over the "absent regulations" case.

EPA next suggested the possibility of certain modifications to this very expensive alternative, each of which would offer some cost savings. First, the Agency suggested allowing an alternative procedure for monitoring sulfur dioxide, flow, and opacity at "gas-fired" units, thus relieving those units from the requirement of installing some monitoring equipment. EPA estimated that use of this procedure would result in a savings of about $176 million as compared to Option 1.

Second, EPA suggested allowing an exception to CEMS for units retiring before January 1, 1995. The Agency estimated that this exception would result in a savings of about $75 million over Option 1.

Third, EPA suggested that if the Agency required all sources to use standardized electronic reporting, this would result in a savings of about $45 million over Option 1.

Finally, the Agency indicated that if it adopted each of these modifications to Option 1, the result would be a total cost

to industry of about $2.6 billion, or a savings of about $278 as compared to Option 1.

In short, EPA's RIA provides only a brief examination of one basic approach for implementing the monitoring requirements under the Acid Rain Program with a few limited modifications, most of which are in the nature of fine-tuning. Many significant issues that have been brought to the attention of the Agency are absent from the RIA. As a result, EPA's RIA is insufficient to support its draft monitoring proposal because it both ignores significant alternative approaches and fails to present a meaningful analysis of the alternative that was chosen by EPA.

I. The RIA Ignores Important Alternative Approaches

Before completing its draft proposal and RIA, EPA had the benefit of extensive meetings with the Acid Rain Advisory Committee (ARAC) and its Emissions Monitoring Subcommittee. During those discussions, members of the Subcommittee as well as other interested parties raised and discussed, often in response to requests from EPA, written proposals on various alternative approaches to meeting EPA's regulatory goals. While the limited alternatives considered in the RIA were discussed during the ARAC process, the RIA ignores the major alternative approaches that were raised.

The following issues and alternatives for monitoring under the Acid Rain Program are among the major approaches that were identified and discussed at length during the ARAC process, but ignored by EPA in drafting the RIA and the proposed regulations:

CEM Quality Assurance and Control (QA/QC)

- various alternative performance standards and QA/QC requirements for CEMS, including less stringent standards for relative accuracy and calibration error; and

- reliance on the daily calibration error test to guard against monitor bias, rather than the infrequent, "snapshot" relative accuracy test audit.

Missing Data Estimation

- use of accurate estimation methods for filling in missing data when CEMS availability is above 90%, rather than use of methods that deliberately overestimate emissions (e.g., use of past maximum values); and

- providing a 90% monitor availability threshold, which in combination with a reasonable missing data estimation method, has been shown to produce just as accurate annual SO_2 and NO_x emissions values as will the higher availability thresholds chosen by EPA, at lower costs.

Alternatives to CEMS

- an alternative for monitoring sulfur dioxide and volumetric flow at oil-fired units and low capacity units;

- an alternative for monitoring nitrogen oxides at gas/oil-fired boiler units, peaking units, and combustion turbines;

- an alternative for monitoring volumetric flow in cases where a flow monitor cannot be located in accordance with applicable location criteria;

- an alternative for certain units sharing a common stack; and

- an alternative for opacity monitoring in locations where such monitoring is not feasible, i.e., downstream of certain sulfur dioxide control devices.

Perhaps recognizing the insufficiency of its RIA, EPA states in the RIA that a number of issues, while being explored by EPA, are not treated in the RIA because of "the difficulty of

assigning dollar values to them." However, under EO 12291, EPA is under an obligation to perform the analysis and to consider any alternative approach that would substantially achieve the same regulatory goals, despite the inherent difficulty of estimating costs. It is significant that EPA did not assert that any of the ignored alternative approaches would not achieve EPA's goals and thus did not require analysis.

Moreover, because EPA was able to estimate the cost to industry associated with EPA's draft proposed performance standards, EPA should also have been able to estimate the costs of other, less stringent, performance standards. Similarly, because EPA was able to estimate the cost savings of allowing an alternative monitoring procedure for "gas-fired" units, EPA should also have been able to estimate the savings associated with allowing other alternatives, such as an alternative for "oil-fired" units.

Finally, utility industry representatives of ARAC provided a method for doing cost/benefit analyses for various missing data options. The Agency has acknowledged the usefulness of this method, but did not attempt to use it in the RIA for evaluating reasonable alternatives to the stringent draft proposed missing data regulations.

II. The RIA Fails to Present a Meaningful Analysis of EPA's Preliminary Proposal

EPA has also failed in the RIA to perform a meaningful cost/benefit analysis of its draft proposal, as required by

EO 12291. A meaningful analysis would require, at a minimum, that the Agency specifically identify the goals to be achieved by its monitoring program, and evaluate the costs and benefits of its proposal in light of those goals.

With regard to benefits, EPA did not even attempt to assess, in the RIA, the benefits of its draft monitoring proposal apart from the benefits expected as a result of the Agency's entire package of regulations under the Acid Rain Program.[8/] While EPA did include in the preamble to its monitoring proposal some description of the expected benefits of its proposal, the Agency made no attempt to describe them in the RIA. For example, although EPA outlined in the preamble some of the benefits that EPA expects to secure as a result of changes made to existing CEM performance standards and requirements under Subpart Da,[9/] a meaningful analysis requires that the Agency look at those benefits in the context of the RIA.

With regard to costs, EPA ignored many of the costs associated with its draft proposal. For instance, EPA excluded from its analysis any assessment of the costs associated with

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8/ EPA's only discussion of benefits in the RIA involves the environmental benefits of the SO_2 reductions that will be achieved by the Acid Rain Program and the Agency's conclusions that the cost of the program as a whole will be reduced by EPA's package of regulations.

9/ The ARAC Monitoring Subcommittee unanimously recommended, and EPA staff agreed, that existing CEM regulations applicable to new sources under 40 C.F.R. Part 60, Subpart Da, should be used as a starting point in developing performance specifications under the Acid Rain Program.

retrofitting older units with CEMS. Moreover, the RIA does not examine the costs imposed by filling in missing data with deliberately inflated values. Without an estimate of such costs, the Agency is in no position to evaluate its proposal or any alternative approaches.

III. Revisions to RIA Needed to Make it Comply with EO 12291

In order to comply with EO 12291, the Agency must properly articulate specific regulatory goals for the program. The Agency must then describe and consider the alternative proposals discussed by the ARAC Monitoring Subcommittee.

In examining alternatives, the Agency must identify alternative approaches that would "substantially achieve" the Agency's goals, and perform a cost/benefit analysis of each alternative approach. In the event that the analysis shows that such an alternative could achieve the goals at a lower cost, the Agency must include the alternative in its proposed regulations or else provide an "explanation of the legal reasons why such alternatives" could not be adopted.

Finally, the Agency must perform a meaningful cost/benefit analysis of its final proposal to ensure that the Agency's goals in implementing the statute are consistent with its responsibility to impose the "least net cost" to society and to identify any areas in which additional alternatives should be considered.

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U.S. Department of Justice

Environment and Natural Resources Division

Office of the Assistant Attorney General

Washington, D.C. 20530

October 4, 1991

Mr. William G. Rosenberg
Assistant Administrator
for Air and Radiation
U.S. Environmental Protection Agency
Washington, D.C. 20460

Dear Bill:

As you requested, we have reviewed two legal questions that have arisen in the course of developing regulations to implement the acid rain provisions of the Clean Air Act Amendments of 1990 (CAAA), Pub. L. 101-549, 104 Stat. 2468 et seq. (Nov. 15, 1990).[1] The specific issues referred to us concern the definition of "repowering" in section 402(12) of the Act and the applicability of NOx requirements to Phase I compensating units pursuant to section 407 of the Act. The following represents our view of these issues.[2]

I. Definition of "Repowering"

Section 409 of the CAAA authorizes the permitting authority to grant four-year extensions of the Phase II acid rain compliance deadline to powerplants that will be "repowered" with a qualifying clean coal technology. "Repowering" is defined in pertinent part in section 402(12) of the Act, 42 U.S.C. § 7651a(12), as follows:

1/ We concur with the conclusion of your Office of General Counsel that neither this letter, which comprises our legal advice to a client agency, nor the legal memoranda prepared by EPA and DOE on these same issues constitute "written comments" on a proposed rule within the meaning of section 307(d)(4)(B)(ii) of the Act, and hence are not subject to the disclosure requirements of the Act. Moreoever, as legal advice prepared in contemplation of litigation, these materials are subject to litigation privileges by virtue of the prejudice to the United States' litigating position that would result from their disclosure.

2/ We further note that with respect to both of these questions the precise dimensions of the Environmental Protection Agency's discretion, as well as the reasonableness of its exercise, may turn on the rulemaking record, and as such obviously cannot be prejudged in advance of the compilation of the record.

> The term "repowering" means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator [of EPA], in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990.

EPA has provided us with a draft opinion concluding that the statutory language and overall scheme, as well as the legislative history of the provision, establish that "Title IV clearly requires replacement or substantial modification of a boiler to qualify for a section 409 repowering extension." Draft Memorandum from Gerald H. Yamada, Principal Deputy General Counsel of EPA, to William G. Rosenberg, Assistant Administrator for Air and Radiation (August 30, 1991) (the EPA memorandum).[3/] The EPA memorandum and draft regulation read the boiler replacement requirement as applying to each of the three categories of technologies that follow the colon in section 402(12): the seven enumerated technologies that immediately follow the colon, or a derivative of those technologies approved by EPA in consultation with DOE, or any other similarly approved technology capable of meeting three enumerated performance criteria. The EPA memorandum maintains that the statute's plain language compels this view and grants the Agency no discretion to adopt any other interpretation.

The Department of Energy (DOE) has provided us with an opinion disputing this conclusion. Memorandum from David B. Rivkin, Jr., Associate General Counsel for Legal Policy and Analysis, to Jeff Holmstead, Associate Counsel to the President (September 12, 1991) (the DOE memorandum). The DOE memorandum suggests two alternatives to the reading of section 402(12) advanced in the EPA memorandum. First, it argues that section 402(12) may be read to define repowering as either (1) replace-

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3/ We further understand EPA to mean that the existing boiler must be physically removed, or so substantially altered that the alterations are tantamount to removing, and that unless this occurs, one cannot qualify for the repowering extension even if the new technology otherwise meets the requirements of this subsection.

ment of an existing boiler with one of the seven enumerated technologies that immediately follow the colon, or an approved derivative of those technologies, or (2) any other similarly approved technology capable of meeting the three enumerated performance criteria. As textual support for this argument, the DOE memorandum notes that while the first two categories of technologies, the named technologies and their approved derivatives, are separated by the disjunctive "or", the third category, approved multipollutant control technologies, is separated from the preceding two technologies by the conjunction "and". The DOE memorandum also suggests that the enumeration of specific performance criteria for multipollutant control technologies, but not for the former two categories, indicates that these criteria were intended as the sole relevant qualifications for this category of technologies.

The DOE memorandum also suggests that the reference to boiler replacement in section 402(12) could be read as referring to only the first category of technologies. In this reading, the use of the disjunctive "or" after the first category, particularly when contrasted with the use of the conjunctive "and" between the latter two categories, "suggest[s] that the boiler replacement requirement need not be applied to those latter two categories." DOE memorandum at 6. In support of this reading, DOE adduces the fact that the last two categories are both subject to EPA approval in consultation with DOE.

Both memoranda support their respective readings of the provision with a canvassing of the legislative history.[4/] The Senate Report on the CAAA stated that the repowering extension "is intended to accommodate the full development and commercialization of certain new or still-developing clean coal technologies as well as any additional lead time that may be required for their installation." S.Rep. No. 228, 101st Cong., 1st Sess. 312-13 (1989). The Report further noted that

> [t]his extension is provided only for repowering technologies because these technologies require substantial modification or replacement of the boiler and other essential components. In order to utilize these

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4/ This letter includes an extended discussion of the provision's legislative history in the interests of completeness. In our view, however, the history of this provision, which is replete with irreconcilable assertions, ambiguities, and arguable misstatements, illustrates the inherent difficulty in using such materials as an aid to statutory interpretation. Not only is it not dispositive of the question here at issue, but it may actually suggest an intentional ambiguity concerning some aspects of the provision. See infra n.9.

> technologies, the boiler must be largely rebuilt. In contrast, other clean coal technologies involve retrofits of existing units which do not entail such substantial modifications and attendant protracted shutdowns. No extension[,] with a commensurate loss of emissions reductions, is warranted for these latter technologies.

Id. at 335. On the other hand, this report language, which at least supports the interpretation advanced in the EPA memorandum, refers to a version of this provision that did not include the third category of technologies, which was added in a bipartisan substitute (Amendment 1293) offered by Senators Mitchell and Dole for the reported bill.[5/] The House version of the bill reported on May 17, 1990 also incorporated the third category of technologies, separated from the former two by "or"; the House Report explained that it "authorizes the Administrator and the Secretary of Energy to jointly expand the list of clean coal technologies in accordance with specific criteria." H.R. Rep. No. 490, 101st Cong., 2d Sess. 371 (1990). In conference, the final category was set off from the former two by "and", as in the Mitchell-Dole substitute, rather than "or", as in the House version.[6/] Just prior to passage of the final legislation, Senator Baucus repeated the above-quoted passage in the Senate Report almost verbatim. 136 Cong. Rec. S16981 (daily ed. October 27, 1990). On the same day, Senator Burdick stated that "it is important to note that the [A]dministration, which worked closely with Senate leadership in developing the definition of repowering that is included in the conference package, did not intend that replacement of an existing boiler be a prerequisite to a multipollutant control technology's qualification as a 'repowering' technology." 136 Cong. Rec. S16899 (daily ed.

5/ In the debate on Amendment 1293, the Senate apparently considered and rejected at least two amendments to Amendment 1293 that would, inter alia, have expanded the definition of repowering to specifically include technologies that do not require boiler replacement. 136 Cong. Rec. S3705 (daily ed. April 2, 1990) (Amendment 1432); 136 Cong. Rec. S3733-3736 (daily ed. April 3, 1990) (same); id. at S3719-3729 (Amendment 1348 (also numbered 1438)).

6/ During the conference, Senator Byrd wrote to Senator Simpson, a conferee, urging him, among other things, to support a change in the definition of the term repowering to specifically include non-replacement technology. Senator Byrd's letter notes that the House and Senate bills contain "almost identical" definitions of the term repowering, and that both provisions "leave open the question" of whether boiler replacement is necessary to qualify for a repowering extension. Letter of Senator Robert C. Byrd to Senator Alan K. Simpson (July 30, 1990).

October 27, 1990). He also introduced into the record a letter of July 2, 1990 from Admiral Watkins to Representative Regula of Ohio, devoted almost exclusively to stating the Administration's view[7] on "the eligibility of technologies not requiring boiler replacement for consideration as repowering technologies," on which he had based his remarks. That letter also stated categorically:

> The Administration worked closely with the Senate leadership in developing the definition of repowering that was adopted in S. 1630 and was thereafter incorporated into H.R. 3030. The intent of the language is to include in the definition of repowering any technology capable of controlling multiple combustion emissions simultaneously, so long as the two criteria specified (i.e., increased boiler efficiency and significantly greater waste reduction) are met. For this class of technologies, boiler replacement is not intended to be a precondition to being considered a repowering technology. Accordingly, the Administration does not believe that further clarification of the definition is required.

Id. at S16901 (emphasis added).[8]

We have carefully considered the arguments advanced in both memoranda and have concluded that the language of section 402(12), though ambiguous in many significant respects, will not support an interpretation which fails to recognize that repowering requires use of an appropriate new technology instead of the existing boiler. Both of the variant readings advanced in the DOE memorandum require reading the provision as if the recital of the three alternative technologies began immediately after the phrase "repowering means", rather than after the phrase "repowering means the replacement of an existing . . . boiler with one of the following clean coal technologies". Such a

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7/ The letter recited that it had been cleared by the Office of Management and Budget, id. at S16901, and was apparently cleared by all interested agencies, including EPA.

8/ Admiral Watkins's letter is probative evidence of the statute's meaning both in its own right, as a contemporaneous exposition of the views of a participant in the legislative negotiations, and in view of the strong evidence of reliance thereon by the legislature. The suggestion in the EPA memorandum that an authoritative statement of the Administration's position in the course of legislative debate is something less than a part of "authoritative legislative history," EPA memorandum at 6, in our view reflects an unrealistic view of the President's role in the legislative process.

reading is inconsistent with the structure of the provision, in which the colon, which is "used chiefly to direct attention to matter that follows (as a list, explanation, or quotation)", see Webster's Ninth New Collegiate Dictionary 266 (1985), follows rather than precedes the reference to boiler replacement. Moreover, all three categories of technologies would be properly described as "the following clean coal technologies".

While it is true that the list following the colon, like the phrase "the following clean coal technologies", could be read to refer exclusively to the seven named technologies (or to those technologies and their approved derivatives), such an interpretation would still fail to provide a satisfactory explanation of the grammatical structure of the provision. Either of these two readings would fail to explain how the technologies that, according to those readings, do not consider boiler replacement, relate to the term "repowering". In other words, when the concept of boiler replacement is removed from either the third category of technologies or the second and third categories, as the DOE memorandum suggests, the provision reads, with respect to those categories:

> The term "repowering" means . . . a derivative of one or more of [the seven] technologies, and any other technology capable of [meeting the three performance criteria].

The difficulty with this reading is that "repowering", whatever the precise scope of its definition, clearly means doing something with a derivative technology or a multipollutant control technology, rather than simply those technologies themselves.[9/]

We find the other textual arguments advanced in support of this interpretation to be unpersuasive. It simply does not follow from the fact that the category of multipollutant control technologies alone has expressly enumerated performance criteria that those criteria are meant to be the exclusive test for qualifying technologies of these types. Because, as both memoranda concede, the third category of technology was intended to encompass types of technologies which were unknown on the date of enactment (and thus, unlike the prior categories, not susceptible to being enumerated in the statute) that category would necessarily have to include explicit defining criteria, whether or not the boiler replacement criterion applied to it. By the same token, the fact that the latter two categories are subject to EPA approval in consultation with DOE does not imply

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9/ The reading advanced in the EPA memorandum, which would include the concept of boiler replacement for all three categories, avoids this particular infirmity.

that this is the only criterion applicable to them. As is noted elsewhere in the DOE memorandum, each is subject to additional criteria (i.e., the requirement of derivation in the case of the second category, and the three performance criteria in the case of the third category).

Similarly, the use of the conjunction "and" rather than the disjunctive "or" to set off the third category, while puzzling, seems to offer no particular support to the interpretations offered in the DOE memorandum. It is the case that because of that usage the interpretation proffered by the EPA memorandum results in a grammatical solecism, in that it reads the provision to define "repowering" as "replacement ... with one of the following ...: [the named technologies] or [their approved derivatives] and [an approved multipollutant control technology]." Given that the existing boiler is to be replaced with only "one of the following ... technologies", the disjunctive "or" should have been used to set off each of the latter two categories. Under the reasoning of the DOE memorandum, however, the use of "and" results in a reading of the provision whereby "repowering" means (a) the replacement of a boiler with either one of the named technologies or an approved derivative, and (b) a multipollutant control technology.[10/] Because the three categories are obviously intended to be used individually rather than in conjunction, such a reading would subvert the statute's structure and manifest purpose. Thus the readings advanced in the DOE memorandum avoid the grammatical inconsistency of EPA's proposed reading, but only at the price of an untenable reading of the provision's overall structure and purpose.[11/] It may be that the conjunction was used to emphasize that the final category of technologies, like the second category, was subject to EPA approval, with DOE consultation. It may also be the case, as the DOE memorandum suggests, that "the conferees agreed to the use of the word 'and' instead of 'or' to separate multipollutant control technologies from [clean coal technology] derivatives, described in the preceding clause." DOE memorandum at 7. If so, the word chosen did not accomplish that purpose.

10/ Under the DOE memorandum's alternative reading, "repowering" would mean (a) replacement of a boiler with one of the named technologies or (b) an approved derivative and a multipollutant control technology.

11/ We do not suggest that arguments from statutory purposes or policies can override clear statutory language. In this case, however, considerations of statutory purpose bolster the textual objections to DOE's reading of the statute.

The legislative history of this section provides no clear and unambiguous answer to the textual problems apparent from the above discussion, and may raise even more questions. Although the Senate Report language cited in the EPA memorandum offers support for its reading, that language referred to a version of the bill containing only the first two categories; the addition of a third category could, as the DOE memorandum suggests, reflect an abandonment of the view expressed in the Report. The House Report language cited by the DOE memorandum is consistent with either interpretation. None of the legislative history sheds light on the decision to use "and" rather than "or" before the final category of technologies. The letter from Admiral Watkins to Representative Regula and Senator Burdick's discussion of it offer strong support for the interpretation advanced in the DOE memorandum, which is not wholly rebutted by Senator Baucus's repetition of the earlier Senate Report language referring to the unamended provision of the bill. Even where, as in this case, statutory language is not entirely clear, however, such legislative history cannot override textual arguments to the contrary as decisive as those present in this case, or impress on statutory language a meaning almost wholly unsupported by its text. See Train v. City of New York, 420 U.S. 35, 45 (1975) ("[L]egislative intention, without more, is not legislation").

Although section 402(12) appears to exclude two of the interpretations we have considered, it is ambiguous in a number of important respects. Accordingly, it does not follow that the interpretation embodied in the present draft rule is the only statutorily permissible one, as EPA would suggest. In particular, the pivotal phrase "replacement of an existing coal-fired boiler" is undefined in the statute, and its scope is not clearly delineated by its context.[12/] As noted in the EPA

12/ Moreover, to the extent that legislative history may be used to consider the question whether Congress has implicitly delegated discretion to an agency, see EPA memorandum at 3 (citing Chevron, U.S.A. v. NRDC, 467 U.S. 837, 843 n.9 (1984)), but see Blanchard v. Bergeron, 489 U.S. 87, 97 (1989) (Scalia, J., concurring), the legislative history of this provision plainly indicates that the current language of the section embodies repeated attempts to reconcile conflicting interests and policy objectives. Cf. Chevron, supra, at 865 ("Congress attempted to accommodate both interests, but did not do so on the level of specificity presented by these cases. Perhaps that body consciously desired the Administrator to strike the balance at this level . . . ; perhaps it did not consider the question at this level; and perhaps Congress was unable to forge a coalition on either side of the question, and those on each side decided to take their chances with the scheme devised by the agency")(emphasis added).

memorandum, "some of the [seven] listed technologies arguably may not require total boiler replacement [, although] all require such extensive modifications of the boiler that they are tantamount to boiler replacement." EPA memorandum at 3 n.2. Under the principle of eiusdem generis, therefore, EPA clearly has, at a minimum, ample discretion to treat as functional boiler replacement any modifications broadly similar in scope to those involved in installing the seven named technologies.[13/] Such a definition would clearly represent the lower, not the upper, limit on the Agency's discretion to give meaning to the term "replacement." Accordingly, in our view the statute confers on EPA the additional discretion to define boiler replacement in a functional manner that takes into account achievement of the specified performance criteria as well as the degree of boiler modification. By way of example, we note that in the recently proposed WEPCo rule EPA proposes to consider a unit to be "replaced" if it would "constitute a reconstructed unit within the meaning of 40 CFR 60.15." 56 Fed. Reg. 27636 (June 14, 1991). 40 CFR 60.15 defines "reconstruction" as

> the replacement of components of an existing facility 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 set forth in this part.

In short, because "Congress has not directly spoken to the precise question at issue," Chevron, supra, 467 U.S. at 842-43, we believe that EPA enjoys a significant measure of discretion to determine to what extent replacement of less than 100% of the parts of an existing boiler could be deemed replacement for purposes of section 402(12).[14/]

13/ EPA's current draft acid rain permits rule thus would provide that repowering in this context comprises "replacement or substantial modification of the boiler." Nothing in the statute would prohibit EPA from indicating in the proposed rule that this does not require any artificial threshold, defined in terms of how many existing parts are replaced by new parts.

14/ In this regard we note that the Agency's final interpretation is obviously not subject to impeachment by comparison with its earlier formulations, even where those formulations themselves embody permissible alternative

(continued...)

II. Applicability of NOx Requirements to Phase I Compensating Units

Section 408(c)(1)(B) of the Clean Air Act provides that if an owner or operator of an electric utility unit proposes to meet the emissions limitation requirements of Title IV by reducing utilization at or shutting down a unit, the owner or operator must designate in the unit's compliance plan the specific unit(s) that will provide electricity to compensate for the reduced utilization ("the compensating unit"). Section 408(c)(1)(B) then provides that:

> The unit to be used for such compensating generation, which is not otherwise an affected unit under sections 404 and 407, shall be deemed an affected unit under section 404, subject to all of the requirements for such units under this title . . ..

CAA Section 408(c)(1)(B), codified at 42 U.S.C. § 7651g(c)(1)(B).

The question that has arisen in developing proposed regulations regarding this provision is whether the phrase "shall be deemed an affected unit under section 404" subjects a compensating unit not only to the SO2 requirements of section 404, but also to those NOx requirements in section 407 to which section 404 affected units are otherwise subject. EPA has provided us with another draft opinion concluding that "Congress expressly provided in the statute that NOx requirements apply to compensating units [and] [c]onsequently, EPA lacks discretion to promulgate regulations that would exclude such units from coverage." Draft memorandum from Gerald H. Yamada, Principal Deputy General Counsel, to William G. Rosenberg, Assistant Administrator for Air and Radiation (August 30, 1991). The DOE memorandum referred to in the repowering discussion above also addressed this issue, concluding that the statutory provisions in

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14/ (...continued)
interpretations of a provision. See Chevron, supra, 467 U.S. at 863 ("The fact that the agency has from time to time changed its interpretations ... does not ... lead us to conclude that no deference should be accorded the agency's interpretation of the statute. An initial agency interpretation is not instantly carved in stone"). Where the final regulation is supported by the record and not inconsistent with the statute, it will be upheld by the reviewing court even where "the court ... conclude[s] that the agency construction was [not] the only one it permissibly could have adopted ..., or even the reading the court would have reached if the question initially had arisen in a judicial proceeding." Id. at 843 n.11 (citations omitted).

question should instead be construed to apply only the SO2 limits of section 404 to compensating units. We have concluded that EPA is incorrect in asserting that the statute completely forecloses its discretion. Rather, either of the suggested constructions of the statute is legally permissible.15/

The main textual argument advanced in the EPA memorandum is syllogistic. By virtue of section 408(c)(1)(B), compensating units "not otherwise an affected unit under sections 404 and 407 [ ] shall be deemed an affected unit under section 404 . . . ." By virtue of section 407(a), units that "become[ ] [ ] affected units pursuant to [inter alia] section[ ] 404 . . . shall become an affected unit for purposes of this section and shall be subject to the emissions limitations for nitrogen oxides set forth herein." Hence, the EPA memorandum surmises that compensating units subject to section 404's SO2 limitations must also "become an affected unit for purposes of [section 407]." The EPA memorandum also notes the further textual support for its interpretation provided by the concluding phrase of the relevant language in section 408(c)(1)(B): "The [compensating] unit . . . shall be deemed an affected unit under section 404, subject to all the requirements for such units under this title." (Emphasis added). Because affected units under section 404 "shall become . . . affected unit[s] for purposes of [section 407] and shall be subject to the emissions limitations for nitrogen oxides set forth herein," section 407(a), the underscored language of section 408(c)(1)(B) supports the conclusion advanced in the EPA memorandum that compensating units are similarly subject to section 407's NOx limitations.16/

15/ Again, while either construction is legally defensible as a matter of statutory construction, the defensibility of the Agency's final choice will also hinge upon consideration of comments received during the rulemaking.

16/ The DOE memorandum notes the distinction between Phase I compensating units, which by virtue of section 408(c)(1)(B) are "deemed an affected unit under section 404, subject to all of the requirements for such a unit under this title [IV]," and "substitute units" described in section 404(c), which are "deemed affected under this subchapter." The DOE memorandum argues that the latter are thereby made subject to "the full panoply of Title IV obligations," whereas the former "are subjected to only those requirements set forth in section 404," DOE memorandum at 3. The fact that substitute units may be subject to a broader category of requirements than compensating units does not, however, refute the EPA memorandum's textual argument concerning the putatively narrower category of requirements to which compensating units are subject.

The EPA memorandum also cites the overall purposes and structure of Title IV as support for its construction of these provisions. Section 401 of the Act recites as its purpose:

> (b) Purposes.--The purpose of this title is to reduce the adverse effects of acid deposition through reductions in annual emissions of sulphur dioxide of ten million tons from 1980 emissions levels, and, in combination with other provisions of this Act, of nitrogen oxides emissions of approximately two million tons from 1980 emission levels . . . .

Codified at 42 U.S.C. §7651(b).

The EPA memorandum argues that this goal would be compromised if Phase I compensating units were not subject to section 407's NOx emissions limitations. The memorandum also points out that section 411(a) contains an enforcement mechanism that penalizes sources on an annual, per-ton basis for exceeding their NOx emissions limitation requirement or their SO2 allowances. Of particular relevance in this regard is the penalty calculation provision: "That penalty shall be calculated on the basis of the number of tons emitted in excess of the unit's emissions limitation requirement or, in the case of sulfur dioxide, of the allowances the operator holds for use for the unit for that year, multiplied by $2000." From this it would appear that in drafting the excess emissions provision Congress envisioned a system under which a source knew how many tons of NOx per year it could emit, or, in other words, that there would be a utilization component to the emissions rate a source would be required to meet. If a source were thus in effect entitled to emit only a certain number of tons of NOx per year, the EPA memorandum argues, Congress would not have intended to allow sources to evade their automatic penalties for excess tons of NOx emissions by switching to compensating units that were not subject to NOx requirements and thus circumventing an intended reduction in total annual emissions.

The DOE memorandum advances a number of textual arguments to support its conclusion that Phase I compensating units are not subject to the NOx limitations of section 407. First, it notes that although Section 407(a) provides that a coal-fired utility unit becomes subject to section 407's NOx requirements on the date that it "becomes an affected unit pursuant to sections 404, 405, [and] 409. . .", Congress did not include section 408 in the list of sections "pursuant to" which a utility became an affected unit subject to section 407's NOx requirements. This omission is particularly striking given that sections 405 and 409 are

explicitly referenced.[17] The DOE memorandum also emphasizes the use of the phrase "pursuant to . . . section 404", as opposed to "under . . . section 404", as being especially problematic. A common sense reading of what constitutes an affected unit "pursuant to . . . section 404" is that the phrase refers to units that became "affected" by operation of the provisions of section 404. Compensating units, however, become affected units because of language in section 408(c)(1)(B). It is thus difficult to say that a compensating unit became an affected unit "pursuant to" section 404, rather than "pursuant to" section 408.

The DOE memorandum also points out that section 408(c)(1)(B) states that each compensating unit "shall be deemed an affected unit under section 404", rather than "shall be deemed an affected unit under section 404 and 407." Although the EPA memorandum argues that "section 404" is simply shorthand for "section 404 and section 407", this omission is especially troubling because the subsection in which this language is found contains two references elsewhere to "section 404 and 407", indicating congressional awareness of the distinction and lending credence to an intent to exclude affected units under section 407.

With respect to the Act's overall purposes and structure, the DOE memorandum argues that "[although] the statute specifies overall caps for NOx and SO2 emissions, . . . [it] provides quite distinctive approaches for attaining the respective objectives." DOE memorandum at 3. In particular, it notes that the NOx emissions limitations contained in section 407(b) are expressed in terms of emissions rates rather than the utilization levels established by the Act for SO2. Thus, although reduced utilization is a method of compliance with the Act's SO2 limitations, it is not a method of complying with section 407(b)'s NOx emissions rate limitations, since a unit's emissions rate is independent of its utilization level. Indeed, the DOE memorandum posits that the "totality of section 408(c)(1)(B)['s compensating scheme]" is actually addressed to the obverse of the problem identified by EPA: the possibility that a unit would earn "undeserved" SO2 emissions allowances by reducing utilization while increasing its emissions rate. DOE memorandum at 3.

In a similar vein, with respect to the goals of the Act, DOE infers that Title IV, which seeks to achieve the mandated reduction of ten million tons of SO2 annually directly through aggregate annual emissions limitations for each unit, seeks the

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17/ Although the EPA memorandum suggests a rationale for section 407(a)'s express references to sections 404(d) and 409(b), see EPA memorandum at 3-4, it does not attempt to explain why the initial recital of "section 404, 405, [or] 409" did not also include a reference to section 408.

mandated reduction of NOx only indirectly, through the nonaggregated emissions rate limits of section 407(b). Under this reading, the possibility identified by the EPA memorandum that NOx aggregate annual reductions might be compromised by use of compensating units not subject to NOx limitations was one that Congress recognized by casting the NOx emissions limits of section 407(b) as a rate rather than an aggregate annual total. (It should be noted in support of this assessment that the purpose section, which flatly mandates "reductions of . . . ten million tons" of SO2 annually, targets reductions of "approximately two million tons" of NOx emissions.)18/

For reasons apparent from the foregoing discussion, we cannot agree with the assertion in the EPA memorandum that "'Congress has directly spoken to the precise question at issue,'" quoting Chevron, supra, 467 U.S. at 842-43, depriving the Agency of "discretion to promulgate regulations that would exclude [compensating] units from [the section 407 NOx] coverage." EPA memorandum at 1, 2. As is clear from both memoranda, there are very strong textual arguments for each of these different readings of the relevant provisions. Although the syllogism advanced in the EPA memorandum is compelling, its force is severely impaired by its implausible treatment of the "pursuant to" language of section 407(a). Similarly, the EPA memorandum provides no explanation whatever of the failure of that section to reference section 408 and of section 408 to reference section 407 in the operative language at issue in this case -- a particularly striking omission given the other references to section 407 in that provision. By the same token, however, the DOE memorandum provides no satisfactory means of limiting the sweep of section 408(c)(1)(B)'s final relevant clause, which categorically states that compensating units are "subject to all of the requirements for . . . units [affected under section 404] under . . . title [IV]." Our review has not suggested to us any interpretation that would satisfactorily harmonize the conflicting and ambiguous language of these provisions, and accordingly we find the textual evidence nondispositive.

18/ This would especially be the case if EPA had reason to expect that as a practical matter very few Phase I units with the type of burners subject to NOx limitations under section 407 would switch to compensating units, making the air quality effects of this interpretation relatively insignificant. This issue, like a significant number raised by this question, must be assessed in light of the record compiled by EPA in the course of the rulemaking and of EPA's and DOE's expert assessments of the matter.

Similarly, neither of the memoranda comprehensively addresses the arguments drawn from statutory purpose and structure that the other advances. The EPA memorandum does not attempt to directly explain the fact that the section 407 NOx emission limits are expressed in terms that are unrelated to utilization rates and therefore not subject to evasion by reduced utilization; nor does it offer a refutation of DOE's assertion that the compensating unit provision was drafted to address "unearned" SO2 emissions allowances achieved by decreasing utilization combined with increased SO2 emissions rates.

On the other hand, the DOE memorandum makes no effort to explain the section 411 penalty provision, whose calculus of excess NOx emissions appears clearly to require formulation of a utilization rate and which therefore clearly implies that reduced utilization might be a means of compliance with NOx limitations.[19] Similarly, we are not satisfied that the

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19/ We note that the textual evidence on this point in section 408(c)(1)(B) is quite ambiguous. It refers to "an affected source under sections 404 and 407 for which the owner . . . proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit . . . ." The reference to "that section" immediately after a reference to two sections leaves it unclear whether "that section" is, as DOE might surmise, a reference to the only one of the two sections whose "requirements [could be met] by reducing utilization," or simply an imprecise means of referring to both the referenced sections, thereby strengthening EPA's inference about the connection between NOx limits and utilization rates. The legislative history merely shows that the references to section 407 were added by the Senate to section 408(c)(1)(B) in S. 1630 as part of a package of technical amendments offered by Senator Baucus after the rest of the provision had already been drafted, suggesting that the unclear reference was the result of imprecise drafting. See Amendment 1460 to Amendment 1293 to S. 1630, adopted by voice vote April 3, 1990 (136 Cong. Rec. S3802 (daily ed. April 3, 1990) (text of Amendment 1460 printed at 136 Cong. Rec. S4293 (daily ed. April 5, 1990)). Similarly puzzling is the fact that the Conference Committee ultimately chose the Senate provision, which referenced "sections 404 and 407" over the House provision, which referenced only "section 404." See S. 1630, 101st Cong., 2d Sess. Sec. 408(c)(1)(B) (as passed by the Senate April 3, 1990), and S. 1630, 101st Cong., 2d Sess. Sec. 507(c)(1)(B) (as passed by the House of Representatives May 23, 1990), without any apparent explanation for the choice.

We would also note that we are unable to posit a textually

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reference to "approximate" annual NOx tonnage reductions in the goals section of the title entirely answers the objection that DOE's reading of the statute would compromise the statutory reduction targets for no clear policy reason. As with the textual arguments, we are unable to reconcile these conflicting inferences, whose relative weight (and wisdom) may in any case depend upon agency expertise and the rulemaking record.

In light of these unreconciled conflicts and ambiguities in the statute's language, structure, and purposes, we believe that DOE is clearly correct in asserting that Congress has not directly and unambiguously spoken to the precise question at issue. In our judgment, both the proffered interpretations are arguably consistent with the language of the statute. In such circumstances, and in particular given the complexity of the regulatory scheme and the large measure of technical expertise called for in implementing it, the Agency is free to adopt a construction of the statute that "represents a reasonable accommodation of . . . competing interests," following "detailed and reasoned" consideration of the issue. Chevron, supra, 467 U.S. at 865. We would again emphasize that the reasonableness of the Agency's interpretation will depend upon technical and policy judgments beyond our competence and upon thorough consideration of the rulemaking record.

Sincerely,

Barry M. Hartman
Acting Assistant Attorney General

cc: Ray Ludwiszewski, Acting General Counsel, EPA
David Rivkin, Associate General Counsel, DOE

19/ (...continued)
based interpretation of sections 404, 407, and 408 that adequately explains the other two references to section 407 that were included in section 408(c)(1)(B). Since section 407(a) makes clear that, whatever may be the status of section 408 compensating units, section 404 affected units are similarly affected under section 407, the inclusion of explicit references to section 407 in section 408(c)(1)(B) appears neither to expand the scope of its coverage nor to settle the issue of applying section 407 to compensating units. On the other hand, insertion of a reference to section 407 in the final operative clause of section 408(c)(1)(B) (i.e., "shall be deemed an affected unit under section 404 and 407 ...") would have basically settled the issue in this case, and we continue to believe that the omission of such a reference is a serious weakness in EPA's argument.

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(b)(9) Release would disclose geological or geophysical information

ACID RAIN ISSUES

1. JOINT AND SEVERAL LIABILITY

Under the draft proposal, owners and operators of an affected unit and/ participants in multi-unit compliance plans are jointly and severally liable for meeting all requirements of the CAAA and for any penalties associated with a violation of any such requirements.

EPA argues that the CAAA clearly imposes compliance obligations broadly on each owner and operator of an affected unit and that alternative approaches would allow parties to contract away their responsibilities under Federal law. In addition, EPA argues that alternative liability schemes that recognized differences in responsibility would establish administrative and legal barriers to enforcement.

DOE, OIRA and others are concerned that joint and several liability will serve as a major impediment to the formation of multi-party arrangements for compliance--especially multi-unit compliance plans that are important to minimizing the cost of the Acid Rain provisions in the CAAA. These agencies believe that private contracts to assign responsibility should be sufficient to address any problems that could arise in this area. EPA can use these private contracts to guide its enforcement actions and assure compliance with the CAAA.

Recommended Position:

Delete any reference in the proposed regulations to strict, joint and several liability.

2. MINOR PERMITS AMENDMENTS IN THE ACID RAIN TITLE

EPA's draft proposal adopts a set of permit modification procedures that differ in important ways from the procedures proposed as part of EPA's Title V Permitting Rule. In the interest of maintaining consistency with that proposal, EPA has accepted a number of proposed revisions to their discussion of permitting modification issues. EPA has rejected, however, suggested language that would request comment on the appropriateness of allowing a "Minor Permit Amendment" for certain permit changes in place of its so-called "fast-track" modification procedures proposal (i.e., procedures requiring public notice and 30-plus day review). We believe that a request for comment on alternative approaches would leave open for discussion and possible adoption the procedures outlined for "Minor Permit Amendments" as a part of the Title V Permitting proposal.

Come up w/ language

Recommended Position

Request comment on alternative approaches to the "fast-track" procedures, including the minor permit amendment.

3. MONITORING

In drafting the monitoring requirements for the proposal, the Environmental Protection Agency (EPA) explicitly chose to adopted "technology-forcing" requirements to push advances in monitoring technology. There are two key elements to this monitoring scheme: (1) a set of stringent performance criteria in terms of both the accuracy and availability of the monitoring equipment and (2) a procedure for treating "missing data" that penalizes units that fail to meet these stringent performance criteria.

In our discussions with EPA staff at the end of July, they acknowledged that the draft monitoring requirements were overly stringent and reported that they planned to meet with a number of representatives of the utility industry to discuss their concerns. EPA staff promised to provide a revised draft addressing these concerns by the third week of August. EPA briefed us on their proposed revisions to the draft monitoring rule on September 10. This revised set of requirements reflected EPA's discussions with the utility industry, but EPA was not able to come to full agreement with industry representatives.

Two key issues remain:

-- **Missing Data** - The missing data provisions of the proposal specify the procedures that will be used for calculating emissions during periods when a monitor is "down." In a September 26 meeting, all parties within the Administration (DOE, EPA, and EOP staff) reached agreement that focuses on the 90th percentile reading over the previous quarter as the basis for missing data calculations. (The attached Table provides the outlines of that agreement.) DOE believes that the use of the 90th percentile reading will impose a penalty of 10 to 30 percent (above the average level of emissions over the quarter).

In a recent letter (October 3rd) to Administrator Reilly, however, EDF and NRDC took the position that the 90th percentile reading was not sufficiently punitive where missing data problems arise. Instead, EDF and NRDC urge the Administrator to use the maximum reading over the preceding year as the basis for calculating emissions for periods with missing data.

We believe the use of the maximum reading represents an unduly harsh penalty for missing data. DOE estimates that using the maximum (or second highest reading) to replace missing data would result in a penalty of over 200,000 tons of SO2 allowances per year. In addition, use of the maximum observation (or second highest reading) is an unstable and unreliable descriptor of actual emissions (so that it will impose an unstable and essentially arbitrary penalty on individual units). The magnitude of the penalty could range from a doubling to a ten-fold increase over the average level of emissions for the period.

-- Bias Test - EPA plans to include a "bias test" as a part of the stringent performance criteria in its draft proposal. If data generated by the semiannual relative accuracy test suggest that the Continuous Emission Monitor (CEM) is reading below the reference monitor (in a statistical test), then, the operator must either correct the monitor or accept a penalty in terms of a loss of SO_2 allowances equal to the amount of bias. EPA argues that where there is a demonstrable bias in the CEM, some adjustment should be made.

OIRA believes the proposed bias test is unnecessary and should be dropped for the following reasons:

- Other tests (daily calibration, relative accuracy) will address potential monitor problems cited by EPA;
- The bias test is performed at infrequent intervals (6 months, or a year) over the course of a year and is based on a small number of observations;
- Daily calibration testing means that the CEM may be adjusted the next day to center on an alternative "true" reading;
- EPA's estimate of excess SO_2 tons allowed in the absence of the bias test are substantially off the mark; given the daily recalibration of the CEM, OIRA believes that any adjustment required by the bias test will be largely attenuated within several weeks.

OIRA has suggested as an alternative that EPA propose the bias test with an exemption for monitors that have a relative accuracy test score of less than 5 percent (RATA $\leq$ 5 percent);

- The cost to retest after failing the bias test--including purchasing power--for units with RATA $\leq$ 5 percent could be over $1 million per year;

- Given the daily calibration adjustment, OIRA believes the SO_2 "losses" because of the exemption for monitors with RATA $\leq$ 5 percent will be very small; using EPA assumptions the maximum "loss" would be less than 10,000 tons of SO_2 over a year.

- The adoption of this exception will provide utilities with an important incentive to develop more accurate monitors.

Recommended Position and Rationale:

Reinstate the agreement on missing data, and compromise on the bias test by including the 5 percent RATA exemption.

Table I

Agreement on Missing Data

A) Greater than 95 Percent Availability for Monitoring

For missing data for periods of:

- o less than 24 hours: hour before/after
- o greater than 24 hours: 90th percentile (90 days)

B) Monitoring Availability Between 90 and 95 Percent

For missing data for periods of:

- o less than 8 hours: hour before/after
- o from 9 hours to 24 hours: 90th percentile (90 days)
- o greater than 24 hours: 90th percentile (365 days)

C) Less than 90 Percent Availability for Monitor

- o 95th percentile (365 days) for all missing data.

4. NO_x REQUIREMENTS AND REDUCED UTILIZATION

Powerplant units can meet their Phase I SO_2 limits by reducing their utilization. The owner or operator of the plant, however, must identify the other units that will generate additional electricity to compensate for the unit that has reduced its utilization (the "compensating unit"). EPA believes that compensating units should be subject to Phase I NO_x controls, even though these units would not otherwise be subject to NO_x requirements until five years later in Phase II. DOE believes that compensating units should not be subject to NO_x controls until Phase II. The Department of Justice has determined that either view is legally defensible.

Recommended Position and Rationale

Two options are acceptable: (1) EPA should promulgate regulations stating that compensating units are not subject to Phase I NO_x reduction requirements; or (2) Phase I NOx controls should be applied to compensating units provided that these units will not be subject to different NOx controls in Phase II. Unless one of these options are selected, the added burden of meeting NOx controls in Phase I would discourage utilities from taking advantage of reduced utilization as part of a least cost compliance strategy. Option 2 provides utilities with the compensating benefit of knowing that the NOx control regime selected will not change five years later. This would reduce operational flexibility under the CAAA.

5. REPOWERING

The Clean Air Act provides a four-year extension of the January 1, 2000, acid rain compliance deadline for powerplants that install a technology that qualifies as "repowering." The purpose of the extension is to encourage the use of advanced, more efficient technologies. The statutory definition of "repowering" can be interpreted in different ways. The fundamental difference between interpretations involves whether or not replacement of the powerplant boiler is a prerequisite for a technology to qualify as repowering.

Because of questions about how the definition should be interpreted, Secretary Watkins wrote Congressman Regula (R-Ohio) during the clean air debate last year to explain that the definition should be interpreted as not requiring boiler replacement. The Watkins' letter was cleared by EPA and OMB. Because of this assurance, Congressman Regula did not offer an amendment to confirm the interpretation.

Almost one year later, EPA adopted a different interpretation that requires either boiler replacement or "substantial modification" of the boiler. DOE objected to the EPA interpretation as being contrary to the position of the Administration set forth in the Watkins' letter. Because of the difference between the two agencies over a legal interpretation, an opinion was requested from the Department of Justice (DOJ). In its opinion, DOJ concluded that the original DOE position was not legally defensible -- i.e. that the statutory language does require boiler replacement. It also concluded, however, that EPA has the discretion to define boiler replacement as something less than the total replacement of the parts of an existing boiler.

On Tuesday, October 15th, Bill Reilly and Admiral Watkins agreed to simply repeat the statutory language in the Act, and to make a case-by-case determination of which technologies fall under this language.

Recommended Position and Rationale

Consistent with the DOJ opinion, EPA should adopt an interpretation of repowering that requires either boiler replacement or "substantial changes to the boiler necessary to control multiple pollutants, increase efficiency, and reduce waste." The EPA phrase "substantial modification" could lead to WEPCo problems because "modification' of a plant (or in this case, a boiler) automatically subjects the plant to WEPCo. In addition, the "changes" should be tied to the three criteria listed in the definition that must be satisfied in order to qualify as a repowering technology.

OTHER UTILITY RELATED ISSUES

1. SECTION 407 NO_x REQUIREMENTS

Section 407 of Title IV (acid rain) of the Clean Air Act requires Phase I powerplants (with tangential and wall-fired boilers) to meet statutorily established numerical emission standards for NOx. Congress established these standards based on the performance of "low-NO_x burner technology." Section 407 also includes a case-by-case waiver for individual boilers which cannot meet these limits using low NOx burner technology. Such boilers can either use emissions averaging or can apply for an alternative emissions limitation.

The Clean Air Act does not define the term "low-NO_x burner technology." For all but tangential boilers, DOE believes the phrase means low-NO_x burners. In the case of tangential boilers, DOE believes that low NO_x burners often includes "close coupled" overfired air as part of the burner configuration. In DOE's view, all other types of overfired air are adjuncts to the burner and are not considered part of the low-NOx burner technology. EPA, in contrast, believes the phrase -- low NOx burner technology -- means low-NO_x burners plus the use of overfire air for all boilers.

EPA argues that the more expansive definition of low NOx burner technology is needed to meet the NOx reduction goal. EPA bases this goal on its interpretation of the President's original proposal to reduce NOx emissions by 2 million tons from projected NOx levels in the year 2000. EPA believes the NO_x reduction goal cannot be achieved without both low-NO_x burners and overfire air.

According to the Act, however, the 2 million reduction is to include NO_x reductions that occur as a result of all Clean Air Act provisions, that is, nonattainment (Title I), mobile source (Title II), and acid rain (Title IV) requirements. DOE believes these provisions will collectively reduce NO_x emissions by at least 3.7 million tons from a 1980 baseline, even if the more narrow definition of low-NOx burners are used by powerplants.

DOE's belief that the 2-million ton reduction goal will be met is based primarily on an estimated 2.4 million ton NO_x reduction from mobile sources mandated by Title II of the Amendments. Further reductions are expected from the electric utility sector, due to Title I and Title IV requirements. (A DOE analysis is in progress to estimate these reductions.)

Recommended Position

Powerplants should be required to meet the NO_x numerical performance standards. If these standards cannot be met using low NO_x burners technology, individual sources can meet a less stringent alternative emission limit.

2. WEPCo

Under WEPCo, any plant undergoing a physical or operational change meeting the definition of modification, must also meet the more stringent air quality requirements applicable to new sources. Because the addition or refurbishment of pollution controls equipment may trigger a plant modification and the application of more stringent air control requirements, the Administration offered amendments last year to address this concern.

Despite the Administration's legislative proposal, Congress provided only limited relief from WEPCo in the 1990 Clean Air Act Amendments. Instead, Congress formally urged EPA to address WEPCo through changes to its rules.

After several months of work, EPA issued a proposed WEPCo rule on June 14. The proposed rule addresses both pollution controls and refurbishment projects. Under the rule, pollution control projects would be excluded from WEPCo if they do not cause a plant to be "less environmentally beneficial." This is a case-by-case, somewhat subjective test. Refurbishment projects would be excluded if they do not cause an increase in emissions. Although both tests clearly protect air quality, environmentalists are opposed to the proposed rule. Congressman Waxman has conducted hearing where EPA and DOE were criticized for the proposed rule.

In response to Congressman Waxman's hearing, EPA unilaterally published a notice of its intent to extend the public comment period on WEPCo. In addition, EPA is now proposing to include the transcript of the Waxman hearing in the public docket and to ask for comments on the transcript.

Recommended Position and Rationale

EOP staff recommends that EPA not extend the public comment period as requested, but instead issue a <u>final</u> WEPCo rule by the end of this year as initially planned. Furthermore, EOP staff opposes the inclusion of the Waxman transcript into the public docket. There is some urgency over the timing of the final rule since electric utilities are making compliance decisions now.

3. BACT RULES

EPA's original position called for a "top down" process for determining the Best Available Control Technology (BACT) under the Prevention of Significant Deterioration (PSD) provisions of the CAAA. The top down process requires the applicant to first examining the most stringent (and generally most expensive) option--which is assumed to be BACT unless the applicant can prove that it is not "achievable." Consideration then moves to the next most stringent technology, and so on.

EOP staff argued that top down BACT took too much authority from the states, and was likely to result in needlessly high regulatory costs, as it gave too much weight to the highest-cost control options. In Administrator Reilly's October 26, 1990 letter to CEA Chairman Boskin, he pledged that "EPA will undertake a rulemaking on its BACT policy on an expedited basis to replace current guidelines. The rulemaking, to be proposed to OMB within 120 days, will be based on a cost-effective approach, and the current guidelines will not be a binding precedent."

On 4/19/91, EPA circulated a draft, asking for comments from several interested agencies. Comments on the draft raised a number of issues. On 6/25/91, EPA staff circulated another draft that resolved some of the earlier concerns. Issues remaining are:

1. Must a source consider the <u>most stringent alternative</u>?

2. Should the rule emphasize the option selected or those not selected?

3. Must EPA explicitly walk away from its earlier top-down position on BACT?

4. Is it sufficient to consider <u>incremental costs</u>?

5. Is it sufficient to consider effects on <u>ambient concentrations</u>?

<u>Recommended Resolution and Rationale:</u>

1. Establish a two-stage process that includes screening and then analysis of options. In the screening phase, the permitting authority would be required to provide a comprehensive list of alternatives which may or may not be subject to further analysis. This list would include the most stringent control option. In the second phase, the

permitting authority would be required to evaluate subset of listed technologies that met the screening criteria. Those technologies which did not meet the screening criteria would not have to be analyzed. Under this approach EPA could require consideration of even the most stringent alternative, but not all alternatives would have to be examined in equal detail.

2. The source must explain the reason an option was selected, but need not explain in detail the reason an option was not chosen.

3. [Anna: David Rivkin will provide language for this paragraph.]

4. Consideration of incremental costs should be sufficient, as it is only incremental costs that matter in an economic analysis of this sort.

5. As with incremental costs, the consideration of incremental effects on the relevant ambient concentration is sufficient for analysis under BACT.

Recommended resolutions are currently under consideration by both EPA and EOP staff.

Withdrawal/Redaction Sheet
(George Bush Library)

Document No. and Type	Subject/Title of Document	Date	Restriction	Class.
03. Paper	Acid Rain Issues and Other Utility Related Issues (11 pp.)	n.d.	P-5	

Collection:

Record Group: Bush Presidential Records
Office: Counsel to the President, Office of
Series: Holmstead, Jeffrey
Subseries: Environmental Subject Files
WHORM Cat.:
File Location: Acid Rain [1]

Open on Expiration of PRA
(Document Follows)
By Cap (NLGB) on 10/28/2005

Date Closed: 7/2/2002
FOIA/SYS Case #: 2001-1865-F
Re-review Case #:
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MR Disposition:
Disposition Date:

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Appeal Disposition:
Disposition Date:

RESTRICTION CODES

Presidential Records Act - [44 U.S.C. 2204(a)]

P-1 National Security Classified Information [(a)(1) of the PRA]
P-2 Relating to the appointment to Federal office [(a)(2) of the PRA]
P-3 Release would violate a Federal statute [(a)(3) of the PRA]
P-4 Release would disclose trade secrets or confidential commercial or financial information [(a)(4) of the PRA]
P-5 Release would disclose confidential advice between the President and his advisors, or between such advisors [a)(5) of the PRA]
P-6 Release would constitute a clearly unwarranted invasion of personal privacy [(a)(6) of the PRA]

C. Closed in accordance with restrictions contained in donor's deed of gift.

PRM. Removed as a personal record misfile.

Freedom of Information Act - [5 U.S.C. 552(b)]

(b)(1) National security classified information [(b)(1) of the FOIA]
(b)(2) Release would disclose internal personnel rules and practices of an agency [(b)(2) of the FOIA]
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(b)(9) Release would disclose geological or geophysical information

ACID RAIN ISSUES

1. JOINT AND SEVERAL LIABILITY

Not consistent w/ ~~Polluter~~ Polluter pays

Under the draft proposal, owners and operators of an affected unit and/ participants in multi-unit compliance plans are jointly and severally liable for meeting all requirements of the CAAA and for any penalties associated with a violation of any such requirements.

EPA argues that the CAAA clearly imposes compliance obligations broadly on each owner and operator of an affected unit and that alternative approaches would allow parties to contract away their responsibilities under Federal law. In addition, EPA argues that alternative liability schemes that recognized differences in responsibility would establish administrative and legal barriers to enforcement.

DOE, OIRA and others are concerned that joint and several liability will serve as a major impediment to the formation of multi-party arrangements for compliance--especially multi-unit compliance plans that are important to minimizing the cost of the Acid Rain provisions in the CAAA. These agencies believe that private contracts to assign responsibility should be sufficient to address any problems that could arise in this area. EPA can use these private contracts to guide its enforcement actions and assure compliance with the CAAA.

<u>Recommended Position:</u>

Delete any reference in the proposed regulations to strict, joint and several liability.

2. MINOR PERMITS AMENDMENTS IN THE ACID RAIN TITLE

EPA's draft proposal adopts a set of permit modification procedures that differ in important ways from the procedures proposed as part of EPA's Title V Permitting Rule. In the interest of maintaining consistency with that proposal, EPA has accepted a number of proposed revisions to their discussion of permitting modification issues. EPA has rejected, however, suggested language that would request comment on the appropriateness of allowing a "Minor Permit Amendment" for certain permit changes in place of its so-called "fast-track" modification procedures proposal (i.e., procedures requiring public notice and 30-plus day review). We believe that a request for comment on alternative approaches would leave open for discussion and possible adoption the procedures outlined for "Minor Permit Amendments" as a part of the Title V Permitting proposal.

Recommended Position

Request comment on alternative approaches to the "fast-track" procedures, including the minor permit amendment.

3. MONITORING

In drafting the monitoring requirements for the proposal, the Environmental Protection Agency (EPA) explicitly chose to adopted "technology-forcing" requirements to push advances in monitoring technology. There are two key elements to this monitoring scheme: (1) a set of stringent performance criteria in terms of both the accuracy and availability of the monitoring equipment and (2) a procedure for treating "missing data" that penalizes units that fail to meet these stringent performance criteria.

In our discussions with EPA staff at the end of July, they acknowledged that the draft monitoring requirements were overly stringent and reported that they planned to meet with a number of representatives of the utility industry to discuss their concerns. EPA staff promised to provide a revised draft addressing these concerns by the third week of August. EPA briefed us on their proposed revisions to the draft monitoring rule on September 10. This revised set of requirements reflected EPA's discussions with the utility industry, but EPA was not able to come to full agreement with industry representatives.

Two key issues remain:

-- Missing Data - The missing data provisions of the proposal specify the procedures that will be used for calculating emissions during periods when a monitor is "down." In a September 26 meeting, all parties within the Administration (DOE, EPA, and EOP staff) reached agreement that focuses on the 90th percentile reading over the previous quarter as the basis for missing data calculations. (The attached Table provides the outlines of that agreement.) DOE believes that the use of the 90th percentile reading will impose a penalty of 10 to 30 percent (above the average level of emissions over the quarter).

In a recent letter (October 3rd) to Administrator Reilly, however, EDF and NRDC took the position that the 90th percentile reading was not sufficiently punitive where missing data problems arise. Instead, EDF and NRDC urge the Administrator to use the **maximum** reading over the preceding year as the basis for calculating emissions for periods with missing data.

We believe the use of the maximum reading represents an unduly harsh penalty for missing data. DOE estimates that using the maximum (or second highest reading) to replace missing data would result in a penalty of over 200,000 tons of SO2 allowances per year. In addition, use of the maximum observation (or second highest reading) is an unstable and unreliable descriptor of actual emissions (so that it will impose an unstable and essentially arbitrary penalty on individual units). The magnitude of the penalty could range from a doubling to a ten-fold increase over the average level of emissions for the period.

-- **Bias Test** - EPA plans to include a "bias test" as a part of the stringent performance criteria in its draft proposal. If data generated by the semiannual relative accuracy test suggest that the Continuous Emission Monitor (CEM) is reading below the reference monitor (in a statistical test), then, the operator must either correct the monitor or accept a penalty in terms of a loss of SO_2 allowances equal to the amount of bias. EPA argues that where there is a demonstrable bias in the CEM, some adjustment should be made.

OIRA believes the proposed bias test is unnecessary and should be dropped for the following reasons:

- Other tests (daily calibration, relative accuracy) will address potential monitor problems cited by EPA;
- The bias test is performed at infrequent intervals (6 months, or a year) over the course of a year and is based on a small number of observations;
- Daily calibration testing means that the CEM may be adjusted the next day to center on an alternative "true" reading;
- EPA's estimate of excess SO_2 tons allowed in the absence of the bias test are substantially off the mark; given the daily recalibration of the CEM, OIRA believes that any adjustment required by the bias test will be largely attenuated within several weeks.

OIRA has suggested as an alternative that EPA propose the bias test with an exemption for monitors that have a relative accuracy test score of less than 5 percent (RATA $\leq$ 5 percent);

- The cost to retest after failing the bias test--including purchasing power--for units with RATA $\leq$ 5 percent could be over $1 million per year;

- Given the daily calibration adjustment, OIRA believes the SO_2 "losses" because of the exemption for monitors with RATA $\leq$ 5 percent will be very small; using EPA assumptions the maximum "loss" would be less than 10,000 tons of SO_2 over a year.

- The adoption of this exception will provide utilities with an important incentive to develop more accurate monitors.

Recommended Position and Rationale:

Reinstate the agreement on missing data, and compromise on the bias test by including the 5 percent RATA exemption.

Table I

Agreement on Missing Data

A) Greater than 95 Percent Availability for Monitoring

For missing data for periods of:

- o less than 24 hours: hour before/after
- o greater than 24 hours: 90th percentile (90 days)

B) Monitoring Availability Between 90 and 95 Percent

For missing data for periods of:

- o less than 8 hours: hour before/after
- o from 9 hours to 24 hours: 90th percentile (90 days)
- o greater than 24 hours: 90th percentile (365 days)

C) Less than 90 Percent Availability for Monitor

- o 95th percentile (365 days) for all missing data.

4. NO_x REQUIREMENTS AND REDUCED UTILIZATION

Powerplant units can meet their Phase I SO_2 limits by reducing their utilization. The owner or operator of the plant, however, must identify the other units that will generate additional electricity to compensate for the unit that has reduced its utilization (the "compensating unit"). EPA believes that compensating units should be subject to Phase I NO_x controls, even though these units would not otherwise be subject to NO_x requirements until five years later in Phase II. DOE believes that compensating units should not be subject to NO_x controls until Phase II. The Department of Justice has determined that either view is legally defensible.

Recommended Position and Rationale

Two options are acceptable: (1) EPA should promulgate regulations stating that compensating units are not subject to Phase I NO_x reduction requirements; or (2) Phase I NOx controls should be applied to compensating units provided that these units will not be subject to different NOx controls in Phase II. Unless one of these options are selected, the added burden of meeting NOx controls in Phase I would discourage utilities from taking advantage of reduced utilization as part of a least cost compliance strategy. Option 2 provides utilities with the compensating benefit of knowing that the NOx control regime selected will not change five years later. This would reduce operational flexibility under the CAAA.

5. REPOWERING

The Clean Air Act provides a four-year extension of the January 1, 2000, acid rain compliance deadline for powerplants that install a technology that qualifies as "repowering." The purpose of the extension is to encourage the use of advanced, more efficient technologies. The statutory definition of "repowering" can be interpreted in different ways. The fundamental difference between interpretations involves whether or not replacement of the powerplant boiler is a prerequisite for a technology to qualify as repowering.

Because of questions about how the definition should be interpreted, Secretary Watkins wrote Congressman Regula (R-Ohio) during the clean air debate last year to explain that the definition should be interpreted as not requiring boiler replacement. The Watkins' letter was cleared by EPA and OMB. Because of this assurance, Congressman Regula did not offer an amendment to confirm the interpretation.

Almost one year later, EPA adopted a different interpretation that requires either boiler replacement or "substantial modification" of the boiler. DOE objected to the EPA interpretation as being contrary to the position of the Administration set forth in the Watkins' letter. Because of the difference between the two agencies over a legal interpretation, an opinion was requested from the Department of Justice (DOJ). In its opinion, DOJ concluded that the original DOE position was not legally defensible -- i.e. that the statutory language does require boiler replacement. It also concluded, however, that EPA has the discretion to define boiler replacement as something less than the total replacement of the parts of an existing boiler.

On Tuesday, October 15th, Bill Reilly and Admiral Watkins agreed to simply repeat the statutory language in the Act, and to make a case-by-case determination of which technologies fall under this language.

Recommended Position and Rationale

Consistent with the DOJ opinion, EPA should adopt an interpretation of repowering that requires either boiler replacement or "substantial changes to the boiler necessary to control multiple pollutants, increase efficiency, and reduce waste." The EPA phrase "substantial modification" could lead to WEPCo problems because "modification' of a plant (or in this case, a boiler) automatically subjects the plant to WEPCo. In addition, the "changes" should be tied to the three criteria listed in the definition that must be satisfied in order to qualify as a repowering technology.

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Recommended Position and Rationale

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<u>**Recommended Resolution and Rationale:**</u>

1. Establish a two-stage process that includes screening and then analysis of options. In the screening phase, the permitting authority would be required to provide a comprehensive list of alternatives which may or may not be subject to further analysis. This list would include the most stringent control option. In the second phase, the

permitting authority would be required to evaluate subset of listed technologies that met the screening criteria. Those technologies which did not meet the screening criteria would not have to be analyzed. Under this approach EPA could require consideration of even the most stringent alternative, but not all alternatives would have to be examined in equal detail.

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Recommended resolutions are currently under consideration by both EPA and EOP staff.

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Document No. and Type	Subject/Title of Document	Date	Restriction	Class.
04. Paper	Permitting and Compliance Issues (6 pp.)	n.d.	P-5	

Collection:

Record Group: Bush Presidential Records
Office: Counsel to the President, Office of
Series: Holmstead, Jeffrey
Subseries: Environmental Subject Files
WHORM Cat.:
File Location: Acid Rain [1]

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RESTRICTION CODES

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Permitting and Compliance Issues

The Clean Air Act establishes compliance plan and permitting requirements in order to assure that electric utilities meet the basic goals of the Acid Rain provisions (Title IV) of the Clean Air Act. In its June draft, EPA had adopted a number of unnecessarily rigid compliance plan requirements for substitution and/or reduced capacity utilization strategies to implement these provisions of the Act.

In response to our comments, EPA has made a number of specific changes to respond to our concerns. However, two broad permitting and compliance issues remain:

-- Joint and Several Liability - Under the draft proposal, participants are jointly and severally liable for meeting all requirements of the CAA and for any penalties associated with a violation of any such requirements. In adopting this approach, EPA specifically rejected an alternative approach that would differentiate responsibility depending on the level of control of the various parties.

   EPA argues that the CAA clearly imposes compliance obligations broadly on each owner and operator of an affected unit and that the rejected alternative would allow parties to contract away their responsibilities under Federal law. In addition, EPA argues that an alternative that recognized differences in responsibility would establish administrative and legal barriers to enforcement.

   We are concerned that joint and several liability will serve as a major impediment to the formation of multi-party arrangements for compliance--especially multi-unit compliance plans that are important to minimizing the cost of the Acid Rain provisions in the CAA. We believe private contracts to assign responsibility should be sufficient to address any problems that could arise in this area. EPA can use these private contracts to guide its enforcement actions and assure compliance with the CAA.

-- Minor permit Amendments - EPA's draft proposal adopts a set of permit modification procedures that differ in important ways from the procedures proposed as a part of EPA's Title V Permitting Rule. In the interest of maintaining consistency with that proposal, EPA has accepted a number of proposed revisions to their discussion of permitting modification issues. However, EPA has rejected suggested language that would request comment on the appropriateness of allowing a "Minor Permit Amendment" for certain permit changes in place of its so-called "fast-track" modification procedures proposal (i.e., procedures requiring public notice and 30-plus day review). We believe that a request for comment on alternative approaches would leave open for discussion and

possible adoption the procedures outlined for "Minor Permit Amendments" as a part of the Title V Permitting proposal.

Repowering

The Environmental Protection Agency (EPA) has adopted a definition of "repowering" that requires replacement of the powerplant boiler as a part of the reconstruction project. The definition is important because it defines the kinds of projects that are eligible under the CAA for the "repowering extension" with a 4-year deferral in compliance (until 2004). EPA argues that its definition represents the best interpretation of the statutory language.

The Department of Energy (DOE) disagrees. DOE argues that in the course of the Clean Air Act negotiations the Administration interpreted the legislative language as including projects that do not require boiler replacement. To support its position, DOE cites a July 2, 1990, letter from Secretary Watkins to Congressman Ralph Regula stating that: "the intent of the language is to include in the definition of repowering any technology [meeting three statutory criteria]... For this class of technologies, boiler replacement is not intended to be a precondition to being considered a repowering technology." This letter was agreed to by EPA.

Status: EPA and DOE have prepared a draft memos outlining their respective positions. The Department of Justice (DOJ) has reviewed the EPA and DOE positions and is preparing a letter outlining its views. We understand that DOJ will largely support EPA's position, but that it will allow what DOE is now supporting as compromise language. DOE would like to replace the term "substantial modification" with the statement that a "modification results in either boiler replacement or in substantial changes necessary to increase efficiency, reduce waste, and control multiple pollutants."

Monitoring

In drafting the monitoring requirements for the proposal, the Environmental Protection Agency (EPA) explicitly chose to adopt "technology-forcing" requirements requiring significant advances in monitoring technology. There are two key elements to this monitoring scheme: (1) a set of stringent performance criteria in terms of both the accuracy and availability of the monitoring equipment and (2) a procedure for treating "missing data" that penalizes units that fail to meet these stringent performance criteria.

In our discussions with EPA staff at the end of July, they acknowledged that the draft monitoring requirements were overly stringent and reported that they planned to meet with a number of representatives of the utility industry to discuss their concerns. EPA staff promised to provide a revised draft addressing these concerns by the third week of August. EPA briefed us on their proposed revisions to the draft monitoring rule on September 10. This revised set of requirements reflected EPA's discussions with the utility industry, but EPA was not able to come to full agreement with industry representatives.

Two key issues remain:

-- Missing Data - The missing data provisions of the proposal specify the procedures that will be used for calculating emissions during periods when a monitor is "down." In a September 26 meeting, all parties within the Administration (DOE, EPA, etc.) reached agreement that focuses on the 90th percentile reading over the previous quarter as the basis for missing data calculations. (The attached Table provides the outlines of that agreement.) Using the 90th percentile reading will impose a penalty of the 10 to 30 percent (above the average level of emissions over the quarter).

   In a recent letter (October 3rd) to Administrator Reilly, however, EDF and NRDC took the position that the 90th percentile reading was not sufficiently punitive where missing data problems arise. Instead, EDF and NRDC urge the Administrator to use the **maximum** reading over the preceding year as the basis for calculating emissions for periods with missing data.

   We believe the use of the maximum reading represents an unduly harsh penalty for missing data. In addition, use of the maximum observation is an unstable and unreliable descriptor of actual emissions (so that it will impose an unstable and essentially or arbitrary penalty on individual units).

-- **Bias Test** - EPA plans to include a "bias test" as a part of the more stringent performance criteria adopted by EPA in its draft proposal. If data generated by the semiannual relative accuracy test suggest that the Continuous Emission Monitor (CEM) is reading below the reference monitor (in a statistical test), then, the operator must either correct the monitor or accept a penalty in terms of a loss of SO_2 allowances equal to the amount of bias. EPA argues that where there is a demonstrable bias in the CEM, some adjustment must be made.

OIRA believes the proposed bias test is unnecessary and should be dropped for the following reasons:

- Other tests (daily calibration, RATA) will address potential monitor problems cited by EPA;
- The bias test is performed at infrequent intervals (6 months, or a year) over the course of a year and is based on a small number of observations;
- Daily calibration testing means that the CEM may be adjusted the next day to center on an alternative "true" reading;
- EPA's estimate of excess SO_2 tons allowed in the absence of the bias test are substantially off the mark; given the daily recalibration of the CEM, OIRA believes that any adjustment required by the bias test will be largely attenuated within several weeks.

OIRA has suggested as an alternative that EPA propose the bias test with an exemption for monitors that have a RATA $\leq$ 5 percent;

- The cost to retest after failing the bias test--including purchasing power--for units with RATA $\leq$ 5 percent could be over $1 million per year;
- Given the daily calibration adjustment, OIRA believes the SO_2 "losses" because of the exemption for monitors with RATA $\leq$ 5 percent will be very small;using EPA assumptions the maximum "loss" would be less than 10,000 tons of SO_2 over a year.

Table I

Interagency Agreement on Missing Data

A) Greater than 95 Percent Availability for Monitoring

For missing data for periods of:

- o less than 24 hours: hour before/after
- o greater than 24 hours: 90th percentile (90 days)

B) Monitoring Availability Between 90 and 95 Percent

For missing data for periods of:

- o less than 8 hours: hour before/after
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- o greater than 24 hours: 90th percentile (365 days)

C) Less than 90 Percent Availability for Monitor

- o 95th percentile (365 days) for all missing data.

Withdrawal/Redaction Sheet
(George Bush Library)

Document No. and Type	Subject/Title of Document	Date	Restriction	Class.
05. Paper	Acid Rain Issues and Other Utility Related Issues (10 pp.)	n.d.	P-5	

Collection:

Record Group: Bush Presidential Records
Office: Counsel to the President, Office of
Series: Holmstead, Jeffrey
Subseries: Environmental Subject Files
WHORM Cat.:
File Location: Acid Rain [1]

Open on Expiration of PRA
(Document Follows)
By Cap (NLGB) on 10/28/2005

Date Closed: 7/2/2002	**OA/ID Number:** 45122-001
FOIA/SYS Case #: 2001-1865-F	
Re-review Case #:	
P-2/P-5 Review Case #:	
MR Case #:	**Appeal Case #:**
MR Disposition:	**Appeal Disposition:**
Disposition Date:	**Disposition Date:**

RESTRICTION CODES

Presidential Records Act - [44 U.S.C. 2204(a)]

P-1 National Security Classified Information [(a)(1) of the PRA]
P-2 Relating to the appointment to Federal office [(a)(2) of the PRA]
P-3 Release would violate a Federal statute [(a)(3) of the PRA]
P-4 Release would disclose trade secrets or confidential commercial or financial information [(a)(4) of the PRA]
P-5 Release would disclose confidential advice between the President and his advisors, or between such advisors [a)(5) of the PRA]
P-6 Release would constitute a clearly unwarranted invasion of personal privacy [(a)(6) of the PRA]

C. Closed in accordance with restrictions contained in donor's deed of gift.

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Freedom of Information Act - [5 U.S.C. 552(b)]

(b)(1) National security classified information [(b)(1) of the FOIA]
(b)(2) Release would disclose internal personnel rules and practices of an agency [(b)(2) of the FOIA]
(b)(3) Release would violate a Federal statute [(b)(3) of the FOIA]
(b)(4) Release would disclose trade secrets or confidential or financial information [(b)(4) of the FOIA]
(b)(6) Release would constitute a clearly unwarranted invasion of personal privacy [(b)(6) of the FOIA]
(b)(7) Release would disclose information compiled for law enforcement purposes [(b)(7) of the FOIA]
(b)(8) Release would disclose information concerning the regulation of financial institutions [(b)(8) of the FOIA]
(b)(9) Release would disclose geological or geophysical information

ACID RAIN ISSUES

1. NO_x REQUIREMENTS AND REDUCED UTILIZATION

Powerplant units can meet their Phase I SO_2 limits by reducing their utilization. The owner or operator of the plant, however, must identify the other units that will generate additional electricity to compensate for the unit that has reduced its utilization (the "compensating unit"). EPA believes that compensating units should be subject to Phase I NO_x controls, even though these units would not otherwise be subject to NO_x requirements until five years later in Phase II. DOE believes that compensating units should not be subject to NO_x controls until Phase II. The Department of Justice has determined that either view is legally defensible.

Recommended Position and Rationale

EPA should promulgate regulations stating that compensating units are not subject to Phase I NO_x reduction requirements. Otherwise, this added burden would discourage utilities from taking advantage of reduced utilization as part of a least cost compliance strategy, thereby reducing flexibility under the CAAA.

2. REPOWERING

The Clean Air Act provides a four-year extension of the January 1, 2000, acid rain compliance deadline for powerplants that install a technology that qualifies as "repowering." The purpose of the extension is to encourage the use of advanced, more efficient technologies. The statutory definition of "repowering" can be interpreted in different ways. The fundamental difference between interpretations involves whether or not replacement of the powerplant boiler is a prerequisite for a technology to qualify as repowering.

Because of questions about how the definition should be interpreted, Secretary Watkins wrote Congressman Regula (R-Ohio) during the clean air debate last year to explain that the definition should be interpreted as not requiring boiler replacement. The Watkins' letter was cleared by EPA and OMB. Because of this assurance, Congressman Regula did not offer an amendment to confirm the interpretation.

Almost one year later, EPA adopted a different interpretation that requires either boiler replacement or "substantial modification" of the boiler. DOE objected to the EPA interpretation as being contrary to the position of the Administration set forth in the Watkins' letter. Because of the difference between the two agencies over a legal interpretation, an opinion was requested from the Department of

Justice (DOJ). In its opinion, DOJ concluded that the original DOE position was not legally defensible -- i.e. that the statutory language does require boiler replacement. It also concluded, however, that EPA has the discretion to define boiler replacement as something less than the total replacement of the parts of an existing boiler.

In addition to the legal issue, EPA has also expressed concern over potential emission increases that could result if retrofit technologies qualify as repowering technologies under the clean coal technology extension.

Recommended Position and Rationale

Consistent with the DOJ opinion, EPA should adopt an interpretation of repowering that requires either boiler replacement or "substantial changes to the boiler necessary to control multiple pollutants, increase efficiency, and reduce waste." The EPA phase "substantial modification" could lead to WEPCo problems because "modification' of a plant (or in this case, a boiler) automatically subjects the plant to WEPCo. In addition, the "changes" should be tied to the three criteria listed in the definition that must be satisfied in order to qualify as a repowering technology.

3. JOINT AND SEVERAL LIABILITY

Under the draft proposal, owners and operators of an affected unit and/ participants in multi-unit compliance plans are jointly and severally liable for meeting all requirements of the CAAA and for any penalties associated with a violation of any such requirements. In adopting this approach, EPA specifically rejected an alternative approach that would differentiate responsibility depending on the level of control of the various parties.

EPA argues that the CAAA clearly imposes compliance obligations broadly on each owner and operator of an affected unit and that the rejected alternative would allow parties to contract away their responsibilities under Federal law. In addition, EPA argues that an alternative that recognized differences in responsibility would establish administrative and legal barriers to enforcement.

DOE, OIRA and others are concerned that joint and several liability will serve as a major impediment to the formation of multi-party arrangements for compliance--especially multi-unit compliance plans that are important to minimizing the cost of the Acid Rain provisions in the CAA. These agencies believe that private contracts to assign responsibility should be

sufficient to address any problems that could arise in this area. EPA can use these private contracts to guide its enforcement actions and assure compliance with the CAA.

Recommended Position:

Delete any reference in the proposed regulations to strict, joint and several liability.

4. MINOR PERMITS AMENDMENTS IN THE ACID RAIN TITLE

EPA's draft proposal adopts a set of permit modification procedures that differ in important ways from the procedures proposed as part of EPA's Title V Permitting Rule. In the interest of maintaining consistency with that proposal, EPA has accepted a number of proposed revisions to their discussion of permitting modification issues. EPA has rejected, however, suggested language that would request comment on the appropriateness of allowing a "Minor Permit Amendment" for certain permit changes in place of its so-called "fast-tract" modification procedures proposal (i.e., procedures requiring public notice and 30-plus day review). We believe that a request for comment on alternative approaches would leave open for discussion and possible adoption the procedures outlined for "Minor Permit Amendments" as a part of the Title V Permitting proposal.

Recommended Position

Request comment on alternative approaches to the "fast-track" procedures, including the minor permit amendment.

5. MONITORING

In drafting the monitoring requirements for the proposal, the Environmental Protection Agency (EPA) explicitly chose to adopt "technology-forcing" requirements requiring significant advances in monitoring technology. There are two key elements to this monitoring scheme: (1) a set of stringent performance criteria in terms of both the accuracy and availability of the monitoring equipment and (2) a procedure for treating "missing data" that penalizes units that fail to meet these stringent performance criteria.

In our discussions with EPA staff at the end of July, they acknowledged that the draft monitoring requirements were overly stringent and reported that they planned to meet with a number of representatives of the utility industry to discuss their concerns. EPA staff promised to provide a revised draft addressing these concerns by the third week of August. EPA briefed us on their proposed revisions to the draft monitoring

rule on September 10. This revised set of requirements reflected EPA's discussions with the utility industry, but EPA was not able to come to full agreement with industry representatives.

Two key issues remain:

-- **Missing Data** - The missing data provisions of the proposal specify the procedures that will be used for calculating emissions during periods when a monitor is "down." In a September 26 meeting, all parties within the Administration (DOE, EPA, and EOP staff) reached agreement that focuses on the T percentile reading over the previous quarter as the basis for missing data calculations. (The attached Table provides the outlines of that agreement.) Using the 90th percentile reading will impose a penalty of 10 to 30 percent (above the average level of emissions over the quarter).

In a recent letter (October 3rd) to Administrator Reilly, however, EDF and NRDC took the position that the 90th percentile reading was not sufficiently punitive where missing data problems arise. Instead, EDF and NRDC urge the Administrator to use the **maximum** reading over the preceding year as the basis for calculating emissions for periods with missing data.

We believe the use of the maximum reading represents an unduly harsh penalty for missing data. DOE estimates that using the maximum (or second highest reading) to replace missing data would result in a penalty of over 200,000 tons of SO2 allowances per year. In addition, use of the maximum observation (or second highest reading) is an unstable and unreliable descriptor of actual emissions (so that it will impose an unstable and essentially arbitrary penalty on individual units).

-- **Bias Test** - EPA plans to include a "bias test" as a part of the stringent performance criteria in its draft proposal. If data generated by the semiannual relative accuracy test suggest that the Continuous Emission Monitor (CEM) is reading below the reference monitor (in a statistical test), then, the operator must either correct the monitor or accept a penalty in terms of a loss of SO_2 allowances equal to the amount of bias. EPA argues that where there is a demonstrable bias in the CEM, some adjustment should be made.

OIRA believes the proposed bias test is unnecessary and should be dropped for the following reasons:

- Other tests (daily calibration, relative accuracy) will address potential monitor problems cited by EPA;

- The bias test is performed at infrequent intervals (6 months, or a year) over the course of a year and is based on a small number of observations;

- Daily calibration testing means that the CEM may be adjusted the next day to center on an alternative "true" reading;

- EPA's estimate of excess SO_2 tons allowed in the absence of the bias test are substantially off the mark; given the daily recalibration of the CEM, OIRA believes that any adjustment required by the bias test will be largely attenuated within several weeks.

OIRA has suggested as an alternative that EPA propose the bias test with an exemption for monitors that have a relative accuracy test score of less than 5 percent (RATA $\leq$ 5 percent);

- The cost to retest after failing the bias test--including purchasing power--for units with RATA $\leq$ 5 percent could be over $1 million per year;

- Given the daily calibration adjustment, OIRA believes the SO_2 "losses" because of the exemption for monitors with RATA $\leq$ 5 percent will be very small; using EPA assumptions the maximum "loss" would be less than 10,000 tons of SO_2 over a year.

Recommended Position and Rationale:

Reinstate the agreement on missing data, and compromise on the bias test by including the 5 percent RATA exemption.

Table I

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C) Less than 90 Percent Availability for Monitor

- o 95th percentile (365 days) for all missing data.

OTHER UTILITY RELATED ISSUES

1. SECTION 407 NO_x REQUIREMENTS

Section 407 of Title IV (acid rain) of the Clean Air Act requires Phase I powerplants (with tangential and wall-fired boilers) to meet statutorily established numerical emission standards for NOx. Congress established these standards based on the performance of "low-NO_x burner technology." Section 407 also includes a waiver for boilers which cannot meet these limits on an individual basis using low NOx burner technology. Such boilers can either use emissions averaging or can apply for an alternative emissions limitation.

The Clean Air Act does not define the term "low-NO_x burner technology." For all but tangential boilers, DOE believes the phrase means low-NO_x burners. In the case of tangential boilers, DOE believes that low NO_x burners often includes "close coupled" overfired air as part of the burner configuration. In DOE's view, all other types of overfired air are adjuncts to the burner and are not considered part of the low-NOx burner technology. EPA, in contrast, believes the phrase -- low NOx burner technology -- means low-NO_x burners plus the use of overfire air for all boilers.

EPA argues that the more expansive definition of low NOx burner technology is needed to meet the statutory goal of the Act to reduce NOx emissions by 2 million tons from a 1980 baseline. According to the Act, the 2 million reduction is to include NO_x reductions that occur as a result of all Clean Air Act provisions, that is, nonattainment (Title I), mobile source (Title II), and acid rain (Title IV) requirements. DOE believes these provisions will collectively reduce NO_x emissions by at least 2 million tons, even if the more narrow definition of low-NOx burners are used by powerplants. EPA believes the NO_x reduction goal cannot be achieved without both low-NO_x burners and overfire air.

DOE's belief that the 2-million ton reduction goal will be met is based primarily on NO_x reductions from mobile sources mandated by Title II of the Amendments. These reductions alone are anticipated to exceed 2 million tons. Further reductions are expected from the electric utility sector, due to Title I and Title IV requirements. (A DOE analysis is in progress to estimate these reductions.)

Recommended Position

Powerplants should be required to meet the NO_x numerical performance standards. If these standards cannot be met using low NO_x burners technology, individual sources can meet a less stringent alternative emission limit.

2. WEPCo

Under WEPCo, EPA determines whether an existing powerplant or industrial facility has been "modified" as a result of some physical or operational change to the pant. An existing plant that has been modified is subject to the same stringent air quality control requirements that apply to a new plant (new source requirements). The installation of pollution controls as well as the repair or replacement of equipment (refurbishment) are changes that could cause EPA to determine that a plant has been modified.

In spite of WEPCo amendments offered last year by the administration, Congress provided only very limited relief from WEPCo in the 1990 Clean Air Act Amendments. Instead, Congress formally urged EPA to address WEPCo through changes to its rules.

After several months of work, EPA issued a proposed WEPCo rule on June 14. The proposed rule addresses both pollution controls and refurbishment projects. It represents a dramatic improvement over EPA's old WEPCo policy. Pollution controls would be excluded from WEPCo if they do not cause a plant to be "less environmentally beneficial." This is a case-by-case, somewhat subjective test. Refurbishment projects would be excluded if they do not cause an increase in emissions. Although both tests clearly protect air quality, environmentalists are opposed to the proposed rule. Congressman Waxman has conducted hearing where EPA and DOE were criticized for the proposed rule.

Recommended Position and Rationale

EPA should promulgate a <u>final</u> WEPCo rule that is the same as the <u>proposed</u> rule. The proposed rule will safeguard air quality but not interfere unnecessarily with efforts to control pollution under the Clean Air Act's tight compliance deadlines. In addition, new source requirements would be triggered only where a refurbishment project at a plant has actually caused an emissions increase.

The final WEPCo rule should be promulgated by the end of this year. Electric utilities are making compliance decisions now.

We believe this schedule is important to providing utilities the regulatory certainty that will allow them to choose the most cost-effective compliance strategies to meet the 1995 acid rain compliance deadline.

3. BACT RULES

EPA's original position called for a "top down" process for determining the Best Available Control Technology (BACT) under the Prevention of Significant Deterioration (PSD) provisions of the CAA. The top down process requires the applicant to first examining the most stringent (and generally most expensive) option--which is assumed to be BACT unless the applicant can prove that it is not "achievable." Consideration then moves to the next most stringent technology, and so on.

EOP staff argued that top down BACT took too much authority from the states, and was likely to result in needlessly high regulatory costs, as it gave too much weight to the highest-cost control options. In Administrator Reilly's October 26, 1990 letter to CEA Chairman Boskin, he pledged that "EPA will undertake a rulemaking on its BACT policy on an expedited basis to replace current guidelines. The rulemaking, to be proposed to OMB within 120 days, will be based on a cost-effective approach, and the current guidelines will not be a binding precedent."

On 4/19/91, EPA issued a draft, asking for comments from several interested agencies. Comments on the draft left some issues unresolved. On 6/25/91, EPA staff circulated another draft which however did not resolve all the earlier concerns. Issues remaining are:

1. Must a source consider the <u>most stringent alternative</u>?

2. Should the rule emphasize the option selected or those not selected?

3. Must EPA explicitly walk away from its earlier top-down position on BACT?

4. Is it sufficient to consider <u>incremental costs</u>?

5. Is it sufficient to consider effects on <u>ambient concentrations</u>?

Recommended Resolution and Rationale:

1. Establish a two-stage process: First, screening. Here, the permitting authority might list alternatives not subject to further consideration, including perhaps the most stringent alternatives, saying merely that these did not meet screening standards it had established. Second, evaluation of candidate technologies. Thus EPA could require consideration of even the most stringent alternative, but not all alternatives would have to be examined in equal detail.

2. The source must explain the reason an option was selected, but need not explain in detail the reason an option was not chosen.

3. [Anna: David Rivkin will provide language for this paragraph.]

4. Consideration of incremental costs should be sufficient, as it is only incremental costs that matter in an economic analysis of this sort.

5. As with incremental costs, the consideration of incremental effects on the relevant ambient concentration is sufficient for analysis under BACT.

Recommended resolutions are currently under consideration by both EPA and EOP staff.

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
40 CFR Parts 72, 73, 75, and 77
[FRL-]
Acid Rain Program: Permits, Allowance System, Continuous Emissions Monitoring, and Excess Emissions
AGENCY: Environmental Protection Agency (EPA).
ACTION: Proposed rules.

SUMMARY: Title IV of the Clean Air Act, as amended by Public Law 101-549, the Clean Air Act Amendments of 1990 (the Act), authorizes the Environmental Protection Agency (EPA or Agency) to establish an acid rain program to reduce the adverse effects of acidic deposition. In order to implement this statutory mandate, the acid rain program requirements will eventually be codified in six regulations. Today's notice includes four proposed rulemakings: the permits regulation (40 CFR Part 72); the allowance system regulation (40 CFR Part 73); the continuous emissions monitoring regulation (40 CFR Part 75); and the excess emissions penalties regulation (40 CFR Part 77). These rulemakings constitute the core of the acid rain program with its four interrelated components: the permit, which includes a source's emissions control plans and requirements and allows a source to benefit from the allowance trading system; the allowance system, which provides a source the flexibility to meet its sulfur dioxide (SO_2) emissions limitation requirements economically while providing environmental accountability for collective compliance with the national cap on SO_2 emissions; the continuous emissions monitoring system, which not only ensures source compliance but also instills confidence in the market-based approach by certifying the existence of the "commodity" being traded; and the excess emissions program, which defines the consequences for failing to comply with the acid rain program's SO_2 and nitrogen oxides (NO_x) emissions requirements. Not included in today's FEDERAL REGISTER are the NO_x control program and the requirements for sources that elect to participate by "opting-in" to the acid rain program.

DATES: Compliance Dates: There are seven primary compliance dates which are applicable to all sources affected by today's proposal: February 15, 1993, when Phase I permit applications and proposed compliance plans are due to EPA; November 15, 1993, when Phase I units must install and begin operating their continuous emissions monitoring systems to collect, record, and report emissions data, and when States must submit their Phase II permit programs for review; January 1, 1995, when Phase I compliance begins and when Phase II units must install and begin operating their continuous emissions monitoring systems to collect, record, and report emissions data; January 1, 1996, when Phase II SO_2 permit applications and proposed compliance plans are due to the permitting agency; December 1, 1997, when Phase II SO_2 permits must be issued by states; January 1, 1998, when Phase II NO_x permit applications and compliance plans are due to the permitting agency; and January 1, 2000, when Phase II compliance begins. Other compliance dates for optional exceptions and extensions are specified in the applicable regulation, where appropriate.

Comments: Comments on the rule proposed by this notice must be received on or before [Insert date 60 days after date of publication in the FEDERAL REGISTER]; although written comments should be submitted separately for each rule, the Agency will hold three public hearings on all of today's proposal. The hearings are scheduled to convene at three different locations and at the dates indicated below:

1. December 2 and 3, 1991, at the EPA Education Center, Waterside Mall, 401 M St, SW, Washington D.C.
2. December 9 and 10, 1991, at the Midland Hotel, 172 West Adams at LaSalle, in Chicago, Illinois.
3. December 16, 1991, at the Westin St. Francis, 335 Powell Street, in San Francisco, California.

The hearings, with the exception of the second day in Washington, D.C., will begin at 9:30 a.m., with registration at 9:00 a.m. The second day of public hearings in Washington, D.C. will begin at 12:00 noon, with registration at 11:30 a.m. The hearings will end at 4:30 p.m., unless concluded earlier. Requests to present oral testimony must be received on or before one week prior to final hearing date. Although the Washington, D.C. and Chicago, IL hearings are scheduled for two days, the second day will only proceed if there are more confirmed presenters than can be accommodated in one day. To schedule oral testimony and register attendance regarding the hearings, contact EPA's Public Hearings Hotline, 6 Whitmore Street, Arlington, MA 02174; telephone (617) 641-5375. Callers will receive by mail confirmation of their scheduled testimony and logistical information. Persons who wish to make oral presentations must restrict presentations to 10 minutes and are also encouraged to have written copies of their complete comments for inclusion in the official record. Written comments may be mailed prior to the scheduled hearings to the Hearings Hotline at the above address.
(**NOTE:** Dates and locations for the public hearings will be scheduled before publication).

ADDRESSES: All written comments on these acid rain rules must be identified with the appropriate document control number and must be submitted in duplicate to: EPA Air Docket (LE-131), Environmental Protection Agency, 401 M St., S.W., Washington DC 20460. Written comments on the Permits rule must be identified with the document control number "A-90-38"; written comments on the Allowance System rule must be identified with the document control number "A-91-43"; written comments on the Continuous Emissions Monitoring rule must be identified with the document control number "A-90-51"; and written comments on the Excess Emissions rule must be identified with the document control number "A-91-68". Commenters may have comments on the acid rain program or the core rules in general; such comments may be sent to the Acid Rain Core Rules - General Docket, and must be identified with the document control number "A-91-69".

In addition, commenters may wish to call the Acid Rain Hotline at (617) 641-5367 to request information or ask general questions.

Comments received on these proposed rules will be available for reviewing and copying from 8:30 a.m. to 12:00 p.m. and 1:30 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, in Room M-1500, first floor Waterside Mall, at the address given above.

FOR FURTHER INFORMATION CONTACT:
Brian McLean, Director
Acid Rain Division (ANR-445)
U.S. Environmental Protection Agency
401 M Street, SW
Washington, DC 20460
(617) 641-5367

SUPPLEMENTARY INFORMATION: The contents of this preamble are as follows:

I. Statutory Authority;
II. General Background;
III. Acid Rain Regulations Introduction;
IV. Permits
- A. Overview of the Acid Rain Permit Program
  1. Flexibility
  2. National Consistency
  3. Integration of Titles IV and V
  4. Accountability
  5. Organization of the Rule
- B. Acid Rain General Provisions
  1. Definitions
  2. Applicability
     a. "Existing" and "New Units"
     b. Appendices A and B
     c. Units Not Subject to the Acid Rain Program
     d. Applicability of Program to Specific Categories of Units
     e. Applicability Determinations
     f. Shared Responsibility and Accountability
     g. Submissions
- C. Designated Representative
  1. Role and Certification Requirement
  2. Owner/Operator Liability
  3. Designated Representative, Multiple Unit Permits, and Multiple Source Compliance Options
     a. Multi-Unit Sources
     b. Multi-Source Plans
  4. Certificates of Representation
  5. Issues Concerning Representation
     a. Binding Agreement of Representation
     b. Binding Agreement Regarding the Holding and Distribution of Allowances -- Unanimity Issue
     c. Changing the Designated Representative/Objections
- D. Acid Rain Permit Applications and Compliance Plans
  1. Compliance Planning

a. Compliance Options for Affected Units
b. Multi-Unit Compliance Options
c. Using Multiple Compliance Options
d. Conditional Approval of Compliance Options

2. Mandatory Use of Forms/Paperwork Reduction Act
3. Relationship of Acid Rain Permits to Emissions Monitoring Requirements
   a. Monitoring Plans and Certifications
   b. Alternative Monitoring Applications
   c. Common Stack Monitors
   d. New Units

E. Acid Rain Compliance Options
1. Multi-Unit Requirements
2. Phase I Substitution Plans
   a. Applicable Units/Exclusions
   b. "Common Control" Requirement
   c. Conditions of Plan
   d. Termination of Substitution Plans
3. Phase I Extension Plans
   a. Applicable Units
   b. Transfer Unit Limitations
   c. Control Unit Limitations
   d. Contents of Proposed Phase I Extension Plan
   e. 90% Control Technology Demonstrations
   f. Determining "Order of Receipt" -- Early Ranking Procedure
   g. Prohibition on Termination of Approved Phase I Extension Plans
4. Phase I Reduced Utilization Plans and Under-utilization Accounting Requirements
   a. Background
      (1) Section 408(c)(1)(B)
      (2) Section 403(d)
   b. Concerns Addressed by Limiting the Applicability of Section 408(c)(1)(B)
      (1) Growth at Unaffected Units
      (2) Wholesale Power Agreements
      (3) Operational Flexibility
   c. Distinguishing Between Section 408(c)(1)(B) and Section 403(d) Treatment
   d. Specifics of Section 408(c)(1)(B) Reduced Utilization Plans and Section 403(d) Accounting
      (1) Net Aggregate Phase I Utilization Threshold Test
      (2) System-wide Sales Downturn Threshold Test
      (3) Section 408(c)(1)(B) Reduced Utilization Plans

(a) General Requirements
(b) Sulfur-free Generation Plans
(c) Energy Conservation and Improved Efficiency Plans
(d) Failure to Submit a Section 408 Plan
(e) Applicability of NO_x Requirements to Compensating Units Under Section 408(c)(1)(B) Reduced Utilization Plans
(f) Termination of Compensating Unit Plans

(4) Section 403 Accounting
(a) Treatment of No_x
(b) Treatment of Forced Outages

e. Timing and Accounting Period

5. Phase II Repowering Extensions
a. Effect of Repowering Extension
b. Prohibitions on Termination of Approved Repowering Extension Plans
c. Treatment of Failed and Abandoned Repowering Project
d. Repowering Application Process
e. Qualifying Repowering Technology

6. New Unit Plans
a. Proposal
b. Special Deadlines
c. Compliance Upon Commencement of Operation
d. New Unit Emissions Monitoring Requirements
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I. Statutory Authority

Title IV of the Clean Air Act, as amended by Public Law 101-549, the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency to establish the acid rain program to reduce the adverse effects of acidic deposition.

II. General Background

Acid rain is the accepted term which encompasses a complex set of phenomena that begins with fossil fuel emissions, includes the transport and transformation of those emissions through the atmosphere, and ends with the effects of those emissions and their resulting transformation products on the environment. Specifically, the burning of fossil fuels, particularly coal and oil, releases emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) into the atmosphere. In the atmosphere, SO_2 and NO_x may undergo various chemical reactions, resulting in the transformation of the emissions into chemical products including sulfates, nitrates, sulfuric acid and nitric acid. These compounds can fall to earth near the source or be transported hundreds of miles. They may be deposited during any stage of their transformation, returning to earth as dry deposition in the form of gases, aerosols, and particles as well as wet deposition through precipitation such as rain, fog, or snow. The presence of these emissions and their transformation products in the atmosphere contributes to reduced visibility and is suspected of posing a threat to human health at current levels. The acidic deposition resulting from SO_2 and NO_x emissions and their byproducts damages both ecosystems and man-made materials. Of the approximately 23 million tons of SO_2 and 19 million tons of NO_x emitted annually from all sources in the United States in 1985, about 16 million tons of SO_2 and 7 million tons of NO_x were emitted by electric utilities.

Title IV of the Act authorizes EPA to establish the acid rain program to reduce the adverse effects of acidic deposition. Specifically, the Act mandates a national emissions cap of 8.95 million tons per year on electric utility SO_2 emissions, to be achieved in two phases. In Phase I, which begins in 1995, the 110 largest, highest-emitting utility plants, located in 21 States, must meet an intermediate SO_2 emissions limitation requirement. By 2000, the start of Phase II, virtually all existing utility units with output capacity greater than 25 megawatts and all new utility units will be required to meet emissions limitations. As a result, total annual SO_2 emissions will be reduced by 10 million tons below 1980 levels. In addition, SO_2 sources not explicitly affected by Phase II requirements (e.g. industrial facilities) may elect to participate by "opting-in" to the acid rain program. Title IV also requires that certain coal-fired electric utility boilers reduce their emissions of NO_x through installation of low NO_x burner technologies or their equivalent, at the same time they are required to comply with the SO_2 limitations.

The acid rain program requirements will be codified in six regulations:

Acid Rain Regulation	40 CFR Part Number
Permits	Part 72
Allowance System	Part 73
Opt In	Part 74

Acid Rain Regulation	40 CFR Part Number
Continuous Emissions Monitoring	Part 75
Nitrogen Oxides Control	Part 76
Excess Emissions	Part 77

The rules for opt in and for NO_x control are reserved for future rulemaking actions. In addition, 40 CFR Part 78 is reserved for the acid rain program. EPA is soliciting comment on whether to use Part 78 to contain the appeals procedures for the acid rain program, which are proposed in today's notice as one subpart of the permits rule (Subpart H, 40 CFR Part 72).

Today's notice covers four proposed rulemakings: permits (40 CFR Part 72); the allowance system (40 CFR Part 73); continuous emissions monitoring (40 CFR Part 75); and excess emissions (40 CFR Part 77). Following the general discussion of the acid rain program in this preamble, the reader will find specific discussions tailored to each of the four proposed rulemakings, in order. The reader is directed to send comments on either the proposed rulemakings or the corresponding sections of this preamble to the appropriate docket, as listed in the Addresses section above. If the reader has comments on more than one rulemaking and corresponding section of the preamble, then the reader is encouraged to submit separate comments to the appropriate dockets; at a minimum, if the reader prepares one combined set of comments, then the reader is requested to send duplicate copies of such comments to each of the appropriate dockets.

In order to implement the statutory mandate to develop the acid rain program, EPA solicited comments and ideas from many individuals and organizations. To facilitate detailed discussions, EPA formed the Acid Rain Advisory Committee (ARAC) under the authority of the Federal Advisory Committee Act (5 U.S.C. (App. I) 9(c)) in November of 1990. This Committee included 44 members representing various stakeholder groups, including utilities, emissions control equipment vendors, State Public Utility Commissioners, academicians, coal companies, State air pollution control agencies, labor, and environmental groups. In addition to the Committee members, several hundred people attended the six ARAC sessions, which were held as public meetings, and participated in varying degrees in the discussions. EPA found the ARAC process to be extremely helpful to the Agency in drafting these acid rain program regulations. (For further information about ARAC deliberations, please refer to Air Docket # A-90-39.)

III. Acid Rain Regulations Introduction

The centerpiece of the acid rain program is an innovative trading system with a fixed number of fully marketable allowances. An allowance authorizes the emission of one ton of SO_2. Existing utility sources are allocated allowances based on their historic fuel use and the emissions limitations specified in the Act. Utility units must not emit SO_2 in quantities that exceed the number of allowances they hold. The allowance system regulation (40 CFR Part 73) includes several components, some of which are being proposed on differing time

schedules, as listed below:

ALLOWANCE SYSTEM RULE (40 CFR Part 73)		
Subpart	**Proposed Rule** (date published)	**Final Rule** (target date for publication)
A: Background	[insert today's date]	May, 1992
B: Allocation	March, 1992	December, 1992
C: Tracking	[insert today's date]	May, 1992
D: Transfers	[insert today's date]	May, 1992
E: Auction and Sales	May 23, 1991	November, 1991
F: Conservation and Renewable Energy Reserve	[insert today's date]	May, 1992
G: Small Diesel Refineries	March, 1992	December, 1992

The allowance background component (Subpart A) of the allowance system regulation covers general information, such as applicability and definitions. The allowance allocation component (Subpart B) of the allowance system regulation, which is reserved for future rulemaking action, will include the assignment of allowances to affected sources each year. The allowance tracking component (Subpart C) of the allowance regulation covers the function and content of allowance accounts as well as the responsibilities of authorized agents for the allowance accounts. The allowance transfers component (Subpart D) of the allowance regulation covers the recordation and notification requirements for the certified transfer of allowances. The allowance auction and sale component (already proposed on May 23, 1991, in 56 FR pp 23744-23759 as Subpart D, and renamed in today's proposal as Subpart E) includes the requirements for the direct purchase of allowances from an EPA sponsored auction or sale. The requirements for the demonstration of energy savings from conservation or use of renewable energy which must be met in order to apply for allowances are contained in the Conservation and Renewable Energy Reserve component (Subpart F) of the allowance system regulation. Finally, the Small Diesel Refineries component (Subpart G) of the allowance system regulation, which is reserved for future rulemaking action, will include allowance application requirements for such refineries. Today's proposal includes the primary structure of the allowance system (background, tracking, and trading) and the requirements for applying for allowances from the conservation and renewable energy reserve.

Since allowances are fully transferrable, utilities may meet their emissions control

requirements in the most cost-effective manner possible. However, because the Act explicitly specifies annual SO_2 emissions tonnage limitations for each affected utility unit, in order to operate and to trade allowances each affected source must apply for a permit which, among other things, certifies that the source will hold a sufficient number of allowances to cover its SO_2 emissions, or specifies the source's alternate planned method of compliance. The permit regulation will be codified in 40 CFR Part 72.

In order to ensure that source compliance collectively results in the achievement of the nationally mandated reductions in SO_2 and NO_x emissions, each affected source is required to install a system to continuously monitor the concentration and flow of emissions, in order to collect, record, and report emissions data. The continuous emissions monitoring rule will be codified in 40 CFR Part 75.

Finally, if an affected unit exceeds its emissions limitation for either SO_2 or NO_x, the Act requires the affected source to pay penalties and, for SO_2, to meet emissions offset requirements. These requirements are designed to act as a strong incentive for compliance with the mandated emissions reductions of the acid rain program. The excess emissions penalties requirements will be codified in 40 CFR Part 77.

Because the acid rain program is designed to allow sources to meet the mandated emissions reductions in the most cost-effective manner possible, SO_2 sources not explicitly affected by the Act's requirements (e.g. industrial sources) may elect to participate in the allowance market by "opting in" to the acid rain program. The opt-in rule will be the subject of a separate future rulemaking (to be codified in 40 CFR Part 74). Although opt-in sources may ultimately be subject to some or all of the core components of the acid rain program, all opt-in requirements, including any core rule requirements incorporated into Part 74, will be established through the future rulemaking process. Accordingly, EPA strongly urges that no comments explicitly concerning the opt in program be submitted in response to the current proposal, since EPA will publish a complete notice of proposed rulemaking for the opt in rule in a separate rulemaking process.

The acid rain program addresses the annual average NO_x emissions rate requirements as a separate component of the program. Specifically, certain coal-fired electric utility boilers are required to reduce their emissions of NO_x through installation of low NO_x burner technologies or their equivalent. The NO_x control rule, which will be the subject of a future rulemakings, will be codified in 40 CFR Part 76. However, procedures to apply for some of the NO_x compliance options are addressed in the Permits rule proposed at 40 CFR Part 72.

In summary, the four rules covering the core acid rain program requirements -- the permit, the allowance system, the continuous emissions monitoring system, and the excess emissions program -- are proposed in today's FEDERAL REGISTER following this notice.

IV. Part 72 - Permits Regulations

A. *Overview of the Acid Rain Permit Program.*

Section 408(a) of the Clean Air Act, as amended by Public Law 101-549 (the Act) requires that the Acid Rain program, mandated by Title IV of the Act, be implemented through operating permits. Acid Rain permits must ensure source accountability for the emissions reductions mandated by Title IV of the Act, yet afford sources flexible planning opportunities to help minimize the costs of compliance. In addition, the Acid Rain permit program must integrate smoothly with State operating permits issued under programs approved pursuant to Title V of the Act, yet ensure the national consistency necessary to support the allowance trading market.

1. Flexibility. The Agency believes that an active allowance trading market, supported by flexible compliance planning opportunities, will help affected sources to minimize compliance costs. EPA's goal is to structure simple, flexible and predictable Acid Rain permit program requirements that will promote these objectives. For example, today's proposal would allow source compliance plans that conditionally proposed the use of several alternative compliance options, with procedures and flexible deadlines for affected sources to notify EPA of their decision to rely on (i.e., to activate) one or more of the options. In addition, the proposal would establish expeditious methods for revising permits, consistent with the need for adequate public notice and comment, without undergoing lengthy modification procedures in every case, so that affected sources would be able to revise their permits to allow for more cost-effective compliance methods.

2. National Consistency. National consistency in implementation of the Acid Rain program requirements is necessary to ensure the effective functioning of a national allowance trading market. Inconsistent implementation could affect the value and fungibility of allowances across Regions, States, and localities. This, in turn, could impede the economies inherent in a national market. Today's proposal would, therefore, establish nationally standardized permitting. Standardized forms for permit applications, compliance plans, permits, and compliance certifications are one important mechanism proposed today by which national consistency would be achieved. In addition, to help ensure a nationally consistent body of judicial precedent, today's rule proposes that EPA be given notice of any challenges to Acid Rain permit conditions brought in State court during Phase II of the program, and an opportunity to intervene in the action.

3. Integration of Titles IV and V. Title V establishes a regime for State adoption and EPA approval of operating permit programs for implementing all air quality requirements of the Act (e.g., air toxics, State implementation plans, and during Phase II, Acid Rain standards). (See regulations proposed at 40 CFR Part 70 May 10, 1991 56 FR 21712). The regulations proposed

today at 40 CFR Part 72 set forth requirements for affected sources to obtain Acid Rain permits, or the Acid Rain portion of permits issued under 40 CFR Parts 70 or 71, under three different situations: 1) during Phase I, when EPA is the permitting authority; 2) during Phase II, when the State or local permitting authority issues a 40 CFR Part 70 permit which includes a specific Acid Rain Section; and 3) during Phase II, when EPA is the permitting authority under 40 CFR Part 71 where the State or local agency is not adequately administering or enforcing a 40 CFR Part 70 program. In today's proposal EPA has, thus, endeavored to integrate the Title IV and Title V permit program requirements to the extent that such integration is practicable, is authorized by the statute, and is consistent with the national allowance program, in order to facilitate Federal approval of and transition to State operating permit programs.

Acid Rain permits are required to be issued in accordance with Title V, except "as modified by" the Acid Rain program requirements of Title IV. (See, Sections 408(a) and 506(b) of the Act.) Section 506(b) of Title V states that "The provisions of this title, including provisions regarding schedules for submission and approval or disapproval of permit applications, shall apply to permits implementing the requirements of Title IV except as modified by that title." Parallel provisions appear throughout Section 408, including Subsection 408(a) which provides that the Acid Rain program "shall be implemented, subject to section 403, [dealing with allowances] by permits issued . . . in accordance with the provisions of title V, as modified by this title." These provisions clarify that Title V permits cannot be used to modify or revoke the fundamental requirements of the Acid Rain program, including allowance allocations granted under the authority of Title IV. These provisions also clearly express a strong Congressional intent for the Title IV permit and allowance programs to modify Title V, as necessary, to ensure the integrity of the Acid Rain program, including the orderly functioning of the allowance system. (The Title IV authority to modify provisions of Title V, however, does not apply to requirements found in other titles of the Act that are merely implemented through Title V. For example, Title I State Implementation Plan requirements to which an Acid Rain source is subject cannot be modified by the authority given in Section 408(a).)

Sections 403(f) and 413 of the Act require that nothing in the Acid Rain permit (or in the Acid Rain portion of a 40 CFR Part 70 or 71 permit) would alter any other Clean Air Act requirement, including those designed to protect the National Ambient Air Quality Standards (NAAQS) (e.g., the applicable State Implementation Plan (SIP) limitation). An Acid Rain source may operate flexibly within the allowance trading system, but nothing in the Acid Rain program would excuse non-compliance with any other requirements of the Act. In addition, today's proposal would provide the opportunity for public notice and comment on permit procedure actions as required by Title V. Finally,

consistent with Title V, today's proposal includes permit forms that would be used for the Acid Rain portion of a permit. This approach should help ensure a smooth transition between Phase I EPA and Phase II State permitting, and reduce opportunities for confusion and delay.

Thus, today's proposal includes Acid Rain-specific permit procedures and requirements that would apply to States issuing Clean Air Act permits under programs approved pursuant to Title V of the Act. For example, the rule would require that the Acid Rain permit provisions appear in a separate, stand-alone portion of the State-issued permit, using standardized forms. In addition, each permit would have to prohibit affected units from emitting sulfur dioxide (SO_2) in excess of the allowances held for that unit, consistent with Section 403(f) and other sections of Title IV. As provided in Title IV, today's proposal would require compliance by affected sources and States with the statutorily mandated schedules for permitting and permit terms, and would require, as provided in Sections 408(c)(1)(A) and 408(d)(3), that proposed Acid Rain permit applications and compliance plans be binding on affected sources until approved or superseded by a permit. Today's proposal also includes a limitation, pursuant to Section 408(h)(2) and Section 504(f), that if a permit shield is applied to a permit by the permitting authority under Section 504(f) of the Act, it would only apply with regard to Acid Rain permit terms that unambiguously comply with 40 CFR Parts 72-78.

How to synchronize the State's timing of issuing Title V permits so that permitting for future Title IV requirements occurs at the same time as permitting for other Clean Air Act requirements is also addressed below in the discussion of Subpart I of today's proposal. Phase I permits, which will be issued by the Administrator, will be issued in 1993 with a five-year term of 1995 through 1999. Pursuant to Title IV, State permitting authorities are required to issue Title V permits containing Phase II SO_2 requirements to all affected sources by December 31, 1997. States must also begin processing Phase II Acid Rain NO_x permit applications in 1998. Pursuant to Title V, within four years after a State receives EPA approval of its Title V permit program, it must complete the process of issuing Title V permits for all Clean Air Act requirements to all affected sources in its jurisdiction. Today's preamble describes three approaches States may choose from to coordinate the permitting of Title IV and other Clean Air Act requirements for affected sources. States would be free to choose from any of these approaches or to use any other approach provided it is consistent with the requirements and deadlines for permitting contained in Titles IV and V of the Act.

4. Accountability. The Agency plans to ensure accountability by requiring strict compliance with the stringent excess emissions offset and penalty requirements provided for in

Section 411 of the Act.[1] The excess emissions requirements are proposed today at 40 CFR Part 77. Section 411 of the Act provides that for each ton of SO_2 or NO_x emitted in excess of an affected unit's emissions limitation, the source must pay a statutory base penalty of $2000. This penalty is estimated to be more than twice the expected market value of an allowance. In addition, a unit with excess emissions of SO_2 will be required to expeditiously offset the excess tons emitted. For SO_2 excess emissions, EPA must automatically deduct allowances from the affected unit's account absent an approved alternative offset plan. The Agency believes that the economic implications of these stringent requirements, along with the risk of additional enforcement, will go far to ensure accountability in the program. EPA also plans to ensure strict compliance by affected sources with other requirements of the program, such as the control obligations that apply to Phase I extension units under Section 404(d)(7), and the shared responsibility, as specified in the rule, of the designated representative and multiple owners and operators of affected units for ensuring compliance with the program. Other provisions of today's proposal intended to ensure accountability while maintaining the program's overall flexibility include the rule's heavy reliance on certifications by the designated representative on behalf of owners and operators of affected sources and affected units, and the liability provisions pertaining to multi-unit compliance plans. In addition, while allowing flexible revisions to the permits, the rule provides that no revision can excuse a past violation of a requirement.

5. Organization of the Rule. The Acid Rain permit program regulations proposed today at 40 CFR Part 72 cover applicability, definitions, and other general provisions; Acid Rain designated representative certification procedures and obligations; Acid Rain permit applications and compliance planning requirements; Acid Rain compliance options; Acid Rain permit contents; Acid Rain Phase I implementation; Federal Acid Rain permit issuance procedures; Federal Acid Rain permit appeals procedures; Acid Rain Phase II implementation; Acid Rain permit revision requirements; and Acid Rain compliance certification requirements. In addition, standardized permit program forms are proposed. The organization of the preamble follows the organization of the proposed rule which is presented in loosely chronological order. Thus, since designated representatives must be certified before permits can be issued, (See Section 408(i) of the Act), the proposed requirements concerning designated representative appear first (following general information). The proposed rule then goes through the proposed Phase I and Phase II

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[1] As is stated in section 411(e) of the Act, the requirements of section 411 are in addition to the Act's other enforcement authorities.

requirements. Many requirements of the program would apply to both Phase I and Phase II. Where requirements would apply only to Phase I, they have been separated for the sake of clarity. Those sections will be inapplicable to Phase II sources unless they decide to participate early in the program pursuant to an Acid Rain compliance option as provided in proposed Subpart D.

B. *Acid Rain General Provisions.*

This subpart of the proposed rule includes a section describing to whom the Acid Rain permit program would apply; sections on definitions, measurements and abbreviations, addresses for permit program submissions, and availability of information; reservations of State and Federal authorities; and prohibitions.

1. Definitions. Today's proposal includes a number of definitions. These include definitions from Title IV of the Act which are proposed to be incorporated into the regulations, as appropriate. EPA has also proposed definitions for a number of additional terms. Key definitions are discussed below in discussions of the relevant sections of the rule.

Additional definitions are discussed in the preamble for the other Acid Rain program regulations proposed today, and for the Title V operating permits regulations at 40 CFR Part 70. Language incorporating the definitions of the other Acid Rain program regulations and the Act by reference appears in each part of the Acid Rain program regulations proposed today, and is intended to assist in preserving program integrity. The terms that are proposed to be defined in 40 CFR Part 72 specifically are those central to a clear understanding of the 40 CFR Part 72 provisions.

2. Applicability. Section 72.7 of today's proposal describes the categories of units which would be subject to the program. The definitions in Section 402 of the Act for "affected source", "affected unit", "unit", "utility unit", "existing unit" and "new unit" describe the sources that would be subject to Acid Rain requirements. This section relies on those definitions.

(a) *"Existing" and "New Units".* The Title IV definitions of "existing unit" and "new unit" are different from the definitions for these terms as used in the other programs under the Act (e.g., new source performance standards -- NSPS -- under Title I). Title IV defines new units as those which commence commercial operation on or after enactment (i.e., November 15, 1990), while new units under other titles of the Act generally are defined based on the date of proposal of a new source rule. Therefore, a unit could be classified as a new unit for purposes of NSPS requirements and as an existing unit for purposes of the Acid Rain program.

(b) *Appendices A and B.* To facilitate implementation, today's proposal includes two appendices referenced in the applicability section of the rule (Section 72.7), which identify specific existing units subject to Acid Rain permitting. Appendix A includes Phase I affected units from Table A of Title IV of the Act. Appendix B, which is based on Section 405 of the

Act, lists the additional existing units which are subject to Acid Rain permitting requirements during Phase II. Appendix B units could, however, be designated as affected units during Phase I under Sections 404(b) and (c), and 408(c)(1)(B) of the Act, and would thereby be subject to the Phase I permitting requirements. Appendix B does not include units listed in Appendix A or "new units" even though such units are also subject to Phase II of the program. The list of units in Appendix B of today's proposal is preliminary and subject to revision. A more complete list of affected Phase II units is scheduled for proposal with the Allowance Allocation rule of 40 CFR Part 73, Subpart A, in December, 1991. Any comment on the inclusion or exclusion of specific units in Appendix B should, therefore, be reserved for this future proposal rather than today's proposal. Moreover, today's proposal does not include information on the basic allowance allocations for the units listed in Appendices A and B, or the units' baselines, and the lesser of their actual or allowable 1985 emissions. This information will also be proposed with the December Part 73 proposal.

(c) *Units Not Subject to the Acid Rain Program.* The proposal also identifies several categories of units which would not be subject to program requirements unless they elected to participate in the program, for example, pursuant to the opt-in provisions at 40 CFR Part 74. This list of excepted categories of units is provided to further clarify the scope of the Acid Rain program.

(d) *Applicability of Program to Specific Categories of Units.* The proposal clarifies the applicability of the program for two categories of units. The first category concerns units modified on or after enactment to serve a generator with a nameplate capacity of greater than 25MWe. The statutory definition of "existing unit" excludes any unit which only serves generators with a nameplate capacity of 25MWe or less. It does not, therefore, include units that were modified on or after enactment to serve one or more generators with a nameplate capacity of greater than 25MWe. The Agency proposes to treat any such unit as a "new unit". The Agency believes this interpretation is appropriate since treating such units as "existing units" would cause an exceedance of the 8.95 million ton cap on SO_2 emissions mandated in Section 403 of the Act. Since "existing units" are allocated allowances, whereas "new units" are not, treating such units as "existing units" would also put the Phase II allowance calculations, which the Administrator is required to propose by the end of 1991, in question in perpetuity. If each modified 25MWe unit were classified as an "existing unit" at the time it was modified to serve a larger generator, an indefinite number of allowances would be needed in the future to accommodate such units. As defined in today's proposal, any such unit would be required to obtain allowances to cover SO_2 emissions and comply with the

requirements of 40 CFR Parts 72-78, as specified for new units. The Agency solicits comment on this issue.

The second category of units for which applicability is clarified in today's proposal is combined cycle units. The Agency proposes to exempt existing combined cycle units without auxiliary firing from Acid Rain permitting requirements by including them in the definition of "simple combustion turbine." Existing combined cycle units with auxiliary firing would not be included in this exemption and would, thus, be subject to Acid Rain permitting requirements. The Agency proposes to include combined cycle units without auxiliary firing in the definition of "simple combustion turbine" because of the similarity of their design characteristics. They are a minor reconfiguration of simple combustion turbines. In addition, they use fuel more efficiently than combined cycle units with auxiliary firing. The Agency believes that exempting this category of units from the Acid Rain program is, therefore, consistent with the environmental intent of the Act. By comparison, combined cycle units with auxiliary firing diverge enough in design from simple combustion turbines to make their inclusion in the definition of simple combustion turbine, and hence their exemption from Acid Rain permitting requirements, questionable. However, under today's proposal both types of combined cycle units as well as simple combustion turbines would be subject to Acid Rain program requirements in Phase II, (as new units) if such units commence commercial operation on or after November 15, 1990, because the statutory exemption for simple combustion turbines is only applicable to existing units. The Agency requests comment on the proposed treatment of combined cycle units.

Today's proposal specifies, in accordance with the Act, that any new unit, including a simple combustion turbine or a unit that serves one or more generators of 25MWe or less is subject to the requirements of the Acid Rain program. The Agency requests comment on the effect of this requirement on very small units, and on whether a de minimis exclusion should be included in the final rule. For example, such an exclusion might be appropriate for emergency generators used by hospitals that do not sell electricity during peak load periods.

(e) *Applicability Determinations.* The Agency is considering establishing informal procedures for issuing applicability determinations to sources seeking a final statement regarding whether or not they are subject to Acid Rain program requirements.

(f) ***Shared Responsibility and Accountability.*** Under today's proposal, it will not be unusual for a number of "persons" within the meaning of the Act to be involved in common activities designed, at least in part, to achieve compliance with the Act. In this regard, the proposed rule affords the various persons a great deal of flexibility in designing appropriate compliance strategies. The Agency wishes here to clarify that, where there are violations in situations involving multiple persons, it will ordinarily focus its enforcement activities on

persons responsible for the violations, where such responsibility is apparent from information in the possession of EPA. The Agency also notes the Act does not affect the right of such persons to contractually apportion the financial responsibility for liability based upon violations of the Act.

Under some circumstances, a party to a multi-unit compliance plan may have no responsibility for a particular violation. For example, under a reduced utilization plan involving a Phase I unit and one or more compensating units, if a designated compensating unit had emissions in excess of the allowances held in its Allowance Tracking System compliance subaccount, and the Phase I unit is in full compliance with its own permit and compliance plan obligations, the Agency would focus its enforcement on the compensating unit.

(g) *Submissions.* Section 72.9(a) would require that all non-electronic written Acid Rain program submissions be delivered by certified mail. The certified mail requirement is to ensure that an independent third party would have a record to verify the transmittal. Under this provision, submissions could be sent by traditional forms of postal delivery (e.g., U.S. Postal Service) as well as by private delivery services, provided the service maintains an independent record of delivery verification.

Reservation of Other Federal and State Authorities. Consistent with Sections 403(f) and 413 of the Act, Subpart A would also reserve State and Federal air quality authorities and requirements under other provisions of the Act, including Section 116. This reservation is intended to ensure that nothing in the Acid Rain program, including an Acid Rain program permit provision, would excuse the source's obligation to comply with other, more stringent, requirements, for example, in a State implementation plan. In addition, Subpart A clarifies that the provisions of Title IV and the Acid Rain program rules are in addition to the Agency's authorities under other provisions of the Act.

C. *Designated Representative.*

1. Role and Certification Requirement. Subpart B of today's proposal governs the process for certifying, and the duties of, the designated representative. As a prerequisite to obtaining a permit, Section 408(i) of the Act requires that a designated representative for the owners and operators of each affected unit at the affected source file a certificate of representation with regard to Acid Rain matters. In addition, Section 408(c)(1) and (d)(2) require the designated representative for the affected source to submit the source's permit applications. Under Subpart B, no more than one designated representative must be certified for each affected source. The designated representative would represent the owners and operators of each affected unit at the affected source, as well as the owners and operators of the affected source as a whole, in matters pertaining to the Acid Rain program including: each affected unit's and source's submission of and compliance with Acid Rain permits, permit applications, and compliance

plans; and the holding, transfer and disposition of allowances for each affected unit at the affected source. These duties are consistent with the provisions of Title IV, which require that the owners and operators of affected units act through a "designated representative" with respect to such matters.

The proposed rule interprets the statutory authorities, responsibilities, and duties of the designated representative as establishing a specific category of "operator" role. Under this reading, provisions of the statute requiring a common "owner or operator" (e.g., substitution plans, NO_x averaging) would be satisfied by having a common designated representative. This would be consistent with the traditionally broad interpretation of the term "operator" under the Clean Air Act, which has included any "person" acting in a supervisory or control authority (e.g., site supervisors, plant managers, operating companies). The interpretation proposed today would not, however, alter the fact that the designated representative's supervisory and control authorities are both specific in purpose and fiduciary nature. The designated representative would, thus, not be required by this interpretation to have any additional authorities or duties not contemplated by the statute and today's proposed rules (e.g., the designated representative could, but would not have to be, the plant manager). An alternative reading of the statutory language pertaining to the roles and functions of the "designated representative" would be that a designated representative is not by definition a type of "operator". Under this reading, the provisions in the statute requiring common ownership or operation could not be satisfied merely by having a common designated representative (unless, the designated representative was also an owner or operator of both units.) EPA requests comment on these alternative interpretations of the relationship of "designated representative" to "operator". In addition, the rule provides that the designated representative would be deemed to be the "responsible official" for an affected source with regard to Acid Rain permitting under Title V and 40 CFR Parts 70 and 71. (This provision should not be confused with the use of the term "responsible official" as proposed on May 23,1991 in 40 CFR Part 73 Subpart E, and new Subpart F. The Agency intends to prevent any confusion in this regard by changing any reference to "responsible official" in 40 CFR Part 73, Subpart E, and new Subpart F to "certifying official" when promulgating that rule in final form.)

The role of the designated representative is of critical importance to the functioning of the program. By proposing to require all owners and operators of an affected source and of each affected unit at a source to interact with the Agency exclusively through one designated representative, the proposed rule would afford the regulated community maximum flexibility in compliance planning, and ensure the smooth functioning of the allowance system. At the same time, the proposed approach would

simplify the Agency's administration of the program and ensure source accountability.

The Agency recognizes that the designated representative cannot always be available to perform his or her duties (e.g., due to illness). Therefore, the rule proposes to allow the owners and operators of an affected source to appoint an alternate designated representative to act on behalf of the designated representative when the designated representative is unavailable. The certificate of representation required to be submitted by the designated representative under Subpart B must specify the name and other information identifying the alternate designated representative selected, and the alternate must sign the certificate. The rule specifies that in the event of concurrent and conflicting actions by the designated representative and the alternate, the Administrator shall deem the action of the designated representative as superseding. The rule also specifies how the alternate can be changed. Thus, unless expressly provided to the contrary, whenever the term "designated representative" is used in the rule, it should be read to apply to the alternate designated representative, if any, included in the certificate of representation.

The proposal would ensure that the Agency or State permitting authority could rely on submissions certified by the designated representative, without having to entertain or evaluate alternative submissions by individual owners or operators of the same unit or to seek separate concurrences by individual owners or operators. This approach should ensure a streamlined and expeditious permitting process and eliminate the need for lengthy inquiries into unit ownership before a permit could be issued. Similarly, participants in the allowance market would be able to rely on representations made by the designated representative acting in that capacity, without being forced to consult with the multiple owners of the unit. Instrumental to this is EPA's proposal to treat all submissions by the designated representative as binding on each owner and operator.

2. Owner/Operator Liability. As a result of the binding authority of the designated representative, Subpart B states that the designated representative and the multiple owners and operators of an affected source or affected unit would share liability for any violation by the source or unit of, or any failure by the source or unit to comply with, the requirements of Title IV. In certifying an affected source's permit application, the designated representative and the owners and operators of the affected source and of each affected unit at the source would be bound to comply with its terms, and would be responsible for ensuring the affected source's and unit's compliance with those terms.

The definition of "designated representative" in Section 72.2 would clarify that the representative must be a natural person. EPA considered whether to allow the designated representative to be a corporate entity rather than a natural

person. Such an approach would, however, create a greater risk of disputes regarding representation and was, thus, rejected.

The requirement that the designated representative be a natural person would not result in personal liability on the part of the designated representative in the absence of any criminal wrongdoing. Nor would EPA's proposal interfere with or limit any private indemnification agreements between the designated representative and the source's owners and operators to financially protect the individual representative in the event of a violation. Thus, the designated representative could, for example, be a corporate officer acting in his or her official capacity, risking no more personal liability then would any other officer or operator of the affected source.

In designating a representative to act on their behalf, an affected source's or unit's owners and operators would bind themselves to comply with the terms of any submissions made by the designated representative, and to the actions undertaken by the designated representative, thus, creating shared liability for each and all. This, together with the liability created by the designated representative's certifications, would enable EPA to hold the designated representatives, the owners, and the operators accountable for compliance problems at the affected unit or source, without having to first demonstrate a proper allocation of responsibility among the multiple owners and operators, or between the owners, operators, and the designated representative. The burden of allocating responsibility for noncompliance among multiple owners and operators would be a private matter to be resolved by the interested parties without implicating EPA or any other regulatory authority.

3. Designated Representative, Multiple Unit Permits, and Multiple Source Compliance Options. (a) *Multi-Unit Sources.* Since permits would be issued to each affected source, and affected sources typically will have more than one affected unit, the rule proposes that there be one designated representative certified for each affected source. Thus, even though ownership of multiple units at an affected source might vary, the important programmatic need of dealing with one representative for the affected source would be preserved. The owners and operators of any one affected unit at an affected source would not, however, be liable for violations of the Title IV requirements by another affected unit at the same affected source in which they had no ownership or operator interest merely because the two units shared the same designated representative. Multi-unit liability would only be involved to the extent the two units were governed by a multi-unit compliance plan that was violated, or if the violation was of a source requirement (such as the requirement to submit a complete permit application in a timely manner).

(b) *Multi-Source Plans.* As is provided in Subparts C and D, the rule proposes, consistent with Title IV, to authorize Acid Rain compliance options involving affected units located at more than one affected source. These include substitution plans, Phase I extension plans, reduced utilization plans, and nitrogen

oxides averaging plans. For multiple sources electing any such option, each source's permit application and permit would have to include a copy of the cross-referencing compliance plan.

Except in the case of substitution plans and nitrogen oxides averaging plans, where the Act expressly requires common control or ownership of the affected units involved, EPA proposes to not require a single designated representative for purposes of the multi-unit compliance options authorized by Subpart D, except when the affected units are located at the same affected source. Instead, the proposal would require that any multi-unit plan involving units located at different sources be jointly certified by the respective designated representatives for each source involved. Such certification would bind the individual owners and operators of all units governed by the plan, which would share responsibility for complying with the plan. The proposed role of the designated representative would make it possible for EPA to approve virtually any variation of multi-unit compliance options, thus, affording sources greater flexibility in achieving compliance.

By requiring that all owners and operators of all the units subject to a multi-unit/multi-source compliance option be bound by their designated representatives' joint submission, and that they share liability for ensuring the compliance of each unit subject to the plan, EPA would be shielded from defenses and disputes between and among multiple owners or operators concerning compliance plans and responsibility for any non-compliance. Without these safeguards, EPA would inevitably have to resolve potentially lengthy disputes between multiple owners or operators concerning their separate liability before issuing a permit or enforcing violations of program requirements. This would make it virtually impossible for EPA to authorize some of the more flexible compliance options (e.g., nitrogen oxides averaging plans which did not specify each individual unit's emissions limitation, but simply imposed a weighted-average emissions limitation for all units covered by the plan). Such disputes would erect unacceptable barriers to EPA's ability to enforce the Act's requirements, which, in turn, would preclude the flexibility proposed to be authorized for approval of multi-unit compliance plans.

4. Certificates of Representation. Subpart B of the proposed rule would require the designated representative to submit a certificate of representation stating, among other things, that he or she was selected by an agreement binding on all the owners and operators of the affected units at the source; and,as provided in Section 408(i), that allowances and their proceeds will be deemed to be held for an affected unit according to each owner's respective interest in the unit or pursuant to an agreement entered into by each owner of the unit providing otherwise. In addition, the rule proposes that the terms of the certificate of representation would be deemed to be incorporated into each Acid Rain program submission made by the designated representative. This is essential to establish each element of

the designated representative's authority to bind each owner and operator to subsequent submissions.

5. Issues Concerning Representation. (a) *Binding Agreement of Representation.* The Agency considered several approaches concerning what would be minimally necessary for inclusion in a certificate of representation to establish the representative relationship. The rule would require that the designated representative be selected by an agreement binding on all the owners and operators of each affected unit at the affected source. The Agency considered whether to require the "unanimous consent" of the owners and operators for a designated representative to be certified. Although the owners and operators of affected sources would be left free by today's proposal to privately agree on such a unanimity requirement, the Agency does not believe that it would be appropriate to prescribe the decision-making procedures that multiple owners would have to follow in selecting a representative. EPA seeks to avoid any requirement that would inadvertently alter the traditional business dealings within the utility industry. Since a source would not be able to obtain a permit or engage in allowance transactions until it had a designated representative, requiring "unanimous" agreement would give leverage to dissidents that they might not otherwise have, allowing them to force majority owners and operators into unreasonable concessions simply to remove objections. Today's proposal would afford various ownership interests no less protection than they have under existing agreements.

(b) *Binding Agreement Regarding the Holding and Distribution of Allowances -- Unanimity Issue.* Pursuant to Section 408(i) of the Act, Section 72.20(b)(6) of today's proposal also requires that, in the case of a unit with multiple owners, the designated representative certify that allowances will be deemed to be held, and that the proceeds of allowance transactions will be distributed either (1) in accordance with the respective ownership interests, or (2) if the multiple owners have expressly agreed to a different distribution of allowances by contract, in accordance with that express agreement. Today's proposal specifies that the express contractual agreement providing for a different distribution of allowances and allowance transaction proceeds must be binding on each and every owner of the unit.

EPA seeks comment on whether the rule should also require that the allowance distribution contract be based on a "unanimous" agreement between multiple owners. Although the statute does not expressly provide for such an approach, some commentors believe that one of the statutory purposes of Section 408(i) is to override existing contractual arrangements between owners of a unit to ensure that minority interests are protected. Under that interpretation, existing commercial arrangements regarding how future agreements should be reached would be superseded. For example, a corporate relationship might call for majority vote of the Board of Directors on future agreements,

another business relationship might call for arbitration, and yet another might have given all authority of a business's holdings to a general partner, a lessee, or a trustee. In addition, a Federally imposed "unanimity" requirement could impose a potential chilling effect on the designated representative's actions.

(c) *Changing the Designated Representative/Objections.* The proposal also stipulates the procedures for changing the designated representative, and that EPA would not become involved in private disputes among multiple owners or operators, nor "freeze" allowance accounts or otherwise stop dealing with the designated representative, even if notified of an objection concerning the actions of the designated representative. This approach would not alter private commercial relationships among multiple owners and operators. Furthermore, aggrieved multiple owners and operators would have adequate protection through their commercial agreements and through the courts, if necessary, to obtain injunctive or monetary relief in the resolution of private ownership disputes. Under the proposed rule the owners and operators could replace a designated representative who was not acting in accordance with the agreement of representation. In addition, if the owners and operators no longer agreed to be represented by the designated representative, and the designated representative knew this, the designated representative would no longer be able to truthfully certify in subsequent submissions to the Agency that he or she was duly authorized. Thus, the Agency does not believe that a unilateral decision by the Agency to freeze allowance accounts is the appropriate remedy to protect the rights of owners.

EPA also believes that freezing allowance accounts would undermine the functioning of the allowance market. The allowance market depends on the ability of third parties to rely on the full effectiveness of the recordation of an allowance transfer. A rule that subjected transfers to the possibility that they might be canceled administratively, even after recordation, would introduce uncertainties. These uncertainties could impair the efficiency of the market by either inhibiting activity or imposing additional transaction costs incurred in an effort to guard against such uncertainties. Second, if the mere filing of an objection forced EPA to suspend recordation of transfers to or from the account, unwarranted objections could introduce disorder into the market or force legitimate designated representatives to make unreasonable concessions to satisfy objections, however unwarranted. EPA, as an environmental regulatory agency, is not in a position to judge the legitimacy of an objection, so the Agency could not effectively guard against unwarranted objections.

The proposal would, however, protect the interests of minority owners. Though designated representatives could be selected by simple majority vote, if that is in accordance with the procedure agreed to by multiple owners and operators for making such decisions, the designated representative would be

required to certify that he or she was acting with full authority with every submission to EPA or the permitting authority. If such a certification proved to be untrue - either because an objection from an owner or operator was pending, or because the action violated the rules of the multiple owners and operators agreement for authorizing designated representative actions or for apportioning the allowances among multiple owners - the designated representative would be guilty of making a false certification and risk civil and possibly criminal sanctions under the Act. This affords owners and operators substantial leverage for ensuring that the actions of the designated representative are in accordance with the fiduciary role established by the law.

D. *Acid Rain Permit Applications and Compliance Plans.*

Section 408(a) of the Act specifies that the program be implemented through permits issued to affected sources in accordance with Titles IV and V, which in turn provide that it is illegal for a source to operate without a permit. Consistent with other environmental permit programs, such as the National Pollutant Discharge Elimination System (NPDES) under the Clean Water Act, the Resource Conservation and Recovery Act (RCRA), and as provided by Title V of the Act, this rule would place the burden of ensuring that an affected source is permitted on the responsible official for the source, which in the case of the Acid Rain program is the duly certified designated representative. (See discussion of Subpart B, above). The Act makes it clear that affected sources are responsible for ensuring compliance with the requirements of the Act; this responsibility does not rest with EPA. (See further discussion, below, concerning permit application shields.)

Subpart C sets forth the basic requirements for permit applications, including the requirement to accompany the application with a proposed compliance plan for each affected unit at the source. In accordance with Section 408 of the Act, Subpart C provides that permit applications and proposed compliance plans would be binding on the source until the permit was issued. Today's proposal, therefore, would require that the designated representative certify that the source will comply with certain standard conditions contained on the forms pursuant to the Act. In addition, Subpart C specifies the basic information concerning the affected source and the affected units at the source that permitting authorities would need in order to write an Acid Rain permit. One essential information requirement would be information identifying the source's utility system and North American Electric Reliability Council (NERC) region or subregion of operation. This information would be necessary to implement the reduced utilization and compensating generation provisions of Sections 72.43 and 72.409 of this part, and Sections 408(c)(1)(B) and 403(d) of the Act (See further discussion below).

Another information requirement would be that each unit must specify the most stringent Federally enforceable allowable

emissions limitation for that unit at the time of application. This limitation would be calculated using the annualization factors included with the National Allowance Data Base proposal (Friday, July 19, 1991, 56 FR 33278). These factors will be promulgated in 40 CFR Part 73 at a later date. Subpart C also sets forth the deadlines by which affected sources would be required to apply for initial Acid Rain permits and for Acid Rain permit renewals.

1. Compliance Planning. (a) *Compliance Options for Affected Units.* Section 408(b) requires that the compliance option or options chosen for each affected unit at a source be articulated in the proposed compliance plan submitted with the source's application. Thus, Section 72.32 of today's proposal requires that, except as noted below for multi-unit compliance options, separate compliance options be included in the compliance plan for each affected unit at the source. Since the sulfur dioxide and nitrogen oxides emissions limitations of the Acid Rain program apply to each affected unit, the rule provides that each affected unit is subject to a separate planning requirement. The specific compliance options available under the program are contained in Subpart D of today's proposal. (See, discussion below.) It is important to note, however, that no special compliance planning would be required under 40 CFR Part 72 by the Acid Rain program for sources choosing to purchase allowances to cover their unit emissions, to fuel switch, or (except for Phase I extension, repowering, and some of the NO_x options) to install control equipment. Rather, Acid Rain program compliance planning is limited to units seeking special regulatory treatment as provided in Subpart D.

(b) *Multi-Unit Compliance Options.* The one exception to the separate compliance planning requirement concerns units governed by a multi-unit compliance option approved pursuant to 40 CFR Part 72, Subpart D. These include substitution plans, reduced utilization/compensating unit plans, Phase I extension plans, nitrogen oxides averaging plans, and plans for units using a common stack. The basis for this proposed exception is that units operating under a multi-unit compliance option have interdependent compliance obligations. (See, further discussion of these and other compliance options at Subpart D, below.)

In the case of units operating under any multi-unit compliance plan, exceedances of the emissions limitation governed by the plan (e.g., sulfur dioxide) at any one unit would as a matter of Federal law have to be attributed to all the units governed by the plan. Otherwise, since an individual unit's ability to comply depends on the operations at the other units under the plan, a defense to an offset planning requirement could be raised based on disputes concerning the actions by the other units. Under a substitution plan, for example, an excess emissions situation could be the result of disputes between majority and minority owners concerning the transfer of allowance allocations from the substitution unit's Allowance Tracking

System account established under 40 CFR Part 73 to the originally affected unit's account. Similarly, a nitrogen oxides averaging plan would not be enforceable without such binding obligations.

Under today's proposal disputes concerning liability between the owners and operators of units covered by a multi-unit plan would not be allowed to delay the offset planning obligation. Because the owners and operators of all units governed by a multi-unit plan would share responibility compliance with the offset planning obligation, this section would build into the program a self-regulating element that should minimize, if not totally eliminate, such problems. As is noted above in the discussion of Subpart B, however, nothing in the rule as proposed would in any way limit private indemnification agreements (i.e., private contractual agreements to reimburse individuals for liability they incur in their official capacity in an enforcement action). Such agreements could not, however, be raised as a defense in any Federal enforcement action.

(c) *Using Multiple Compliance Options.* The rule as proposed would allow affected units to rely on one or more of the compliance options provided for in Subpart D of the proposed rule, to meet their SO_2 and NO_x emissions reduction requirements. If one or more of these options were chosen, the permit application would have to include the additional information requirements for that option set forth in Subpart D of today's proposal.

(d) *Conditional Approval of Compliance Options.* In order to afford affected sources maximum flexibility in compliance planning, and to obviate the need and burden to the source of subsequent permit revisions, the designated representative for a source could seek conditional approval, in accordance with Subpart D, of several compliance options. Thereafter, the designated representative would have to notify the Agency of the source's decision to "activate" any one conditionally approved compliance option. In some instances this flexibility may be limited by deadlines or other requirements due to the nature of the option. The reader is referred to the specific sections of today's preamble discussing the compliance options in Subpart D to see what restrictions would apply.

2. Mandatory Use of Forms/Paperwork Reduction Act. The Agency believes that it is important to minimize the imposition of duplicative or inconsistent information requirements on sources. Today's proposal would do so through the use of standardized forms and by codifying certain critical information concerning existing sources in the Appendices. (See, e.g., Appendices A, B and C). It is also important, however, to ensure that all necessary permit information and enforceable requirements be specified in one consolidated format, in order to expedite permit processing, to afford meaningful public review of proposed permit actions, and to ensure compliance. Ensuring that permit applications and proposed compliance plans have complete information is particularly important to the Acid Rain program

since, pursuant to Sections 408(c)(1)(A) and 408(d)(3) of the Act, an Acid Rain permit application and proposed compliance plan submitted in accordance with Title IV is binding on the source until superseded by a permit and approved compliance plan. Today's proposal would, thus, require permit applications to include certain information which EPA could obtain by other methods. In balancing these competing interests, the Agency has determined that the costs to sources of providing certain critical information that might be otherwise available are outweighed by the benefits of having all of the information about a source necessary to write a permit and ensure compliance prior to a permit's effective date provided by the applicant in one document. The Agency requests comment on this approach, and suggestions on whether the Agency could ensure clear articulation of all applicable requirements before the permit is in effect, without requiring their inclusion on the application forms.

The Agency's proposal to require that all applications be submitted on EPA-issued standard forms, and that States and local permitting agencies use these forms when issuing Acid Rain permits for Phase II will also help to ensure national consistency in information requirements for Acid Rain permit applications. Requiring standard forms, whether the permitting authority is EPA, a State, or a local agency, would ensure parity, and, thus, help promote a national allowance market. Nationwide use of standard forms would reduce the administrative burden on affected sources and permitting authorities associated with permitting. Utilities with sources located in more than one State would not have to complete different, and possibly conflicting, applications for each source. In addition, the use of standardized forms would facilitate the burden on States of developing an Acid Rain permitting program, and help ensure against some States inadvertently having more (or less) extensive informational requirements than others.

Ensuring that utilities in different States will have the same permit application requirements and burden should also facilitate a national allowance market. If, for example, one State required considerably more information about the source or more detailed compliance plans prior to issuing an Acid Rain permit than did another State, the source might encounter delays in obtaining permit approval or have greater difficulty making demonstrations. This could add to the source's incremental "cost" of permitting and of obtaining allowances. While costs of compliance may vary from source to source, thus affecting the individual value of allowances, the Agency believes that variations in these costs on the basis of who the permitting authority is, should be avoided to the extent possible. The Agency requests comment on the use of standardized forms nationwide.

EPA is also developing the Acid Rain permit program with a view toward eventual electronic reporting for permit applications and compliance plans for Phase II. Consistent with current EPA policy, set forth at 55 FR 31030 (July 30, 1990), the forms

proposed today have been developed in a way that is compatible with ANSI-X12, a computer-reporting system which is in widespread use throughout the United States for commercial reporting of information. The Agency plans to work with industry and States in developing specifications for compatible electronic reporting of Acid Rain permit applications and compliance plans, and in developing user-friendly software packages to facilitate this reporting. Electronic reporting of applications and compliance plans would not be mandatory, consistent with Agency policy, but would be recommended where feasible. The Agency believes such reporting would be particularly helpful in establishing a truly dynamic permitting and allowance data system. The Agency requests comment on the use of electronic reporting for permit applications and compliance plans.

3. Relationship of Acid Rain Permits to Emissions Monitoring Requirements. (a) *Monitoring Plans and Certifications.* The permit application for the source would have to indicate how each affected unit at the source would meet its emissions monitoring requirements under Section 412 of the Act and 40 CFR Part 75. The Agency is, consequently, proposing in the emissions monitoring rules at 40 CFR Part 75 that the designated representative for each Phase I affected source submit a proposed monitoring plan to EPA for approval for each affected unit at the source, prior to or concurrent with the source's permit application. Section 412 of the Act does not, however, require that the emissions monitoring system verification test results for Phase I units be submitted by the February, 1993 Phase I permit application deadline. Thus, the rule proposes that timely submission of the monitor verification test results and monitor certification be an enforceable permit requirement, and that certifications would be incorporated into the permit upon notification of the designated representative by the Administrator.

(b) *Alternative Monitoring Applications.* Unless a source had obtained Agency approval under 40 CFR Part 75 of an alternative monitoring system by the time a permit application was submitted, the permit would be issued requiring compliance with the CEMS requirements of 40 CFR Part 75. In the event an alternative monitoring system was approved by the Agency after permit issuance, the permit would have to be revised in accordance with Subpart J to authorize use of such alternative. The Agency proposes that permits be revised using the administrative amendment procedure specified in Section 72.303 of today's proposal to include alternative emissions monitoring requirements that have been reviewed and approved by the Administrator under 40 CFR Part 75. This is appropriate since 40 CFR Part 75 provides that such actions by the Administrator would be subject to an opportunity for public comment. Affording any further opportunity for public comment for the sole purpose of incorporating a properly approved emissions monitoring requirement into the permit would, thus, be redundant. Moreover, the administrative amendment procedure includes subsequent public

notice of the revision. The Agency requests comment on this approach.

(c) *Common Stack Monitors.* Section 72.50 specifies the requirements for common stack plans. The Agency proposes that units sharing a common stack shall so specify in the monitoring plan submitted with their permit application, and shall either monitor emissions independently or shall comply with the requirements in that section.

(d) *New Units.* The Agency proposes that all existing Phase II units must have monitors operational and certified by January 1, 1995. Any new unit that becomes affected between January 1, 1995 and December 31, 1999 must have monitors operational and certified by the effective date of the plan under which it becomes a Phase I affected unit.

E. *Acid Rain Compliance Options.*

A fundamental feature of the Acid Rain program is the flexibility provided in the Act for sources to choose cost effective means of complying with the mandated SO_2 and NO_x emissions reductions requirements. Sections 404, 405, 407, 408, 409, and 410 of the Act provide various compliance options by which an affected unit may obtain special relief to assist in its efforts to comply with its emissions limitations under the program. Section 408(b) specifies that the option or options chosen for each affected unit must be articulated in the proposed compliance plan submitted with the permit application for the source. It is important to note, however, that no special compliance planning would be required by the Acid Rain program for sources choosing to fuel switch, or (except for Phase I extension, repowering, and some of the NO_x options) to install control equipment. Rather, Acid Rain program compliance planning is limited to affected units seeking special regulatory treatment as provided in Subpart D.

Subpart D describes the proposed requirements for each of the compliance options specifically authorized by the Act. As provided in Subpart C each permit application would contain at least a standard permit application form specifying information and applicable standard requirements for each affected unit at an affected source. These would include the standard compliance requirement, i.e., a certification for each affected unit that it will meet the applicable emissions limitation requirements of the program in a timely manner, including a certification that for purposes of SO_2 compliance the affected unit will hold enough allowances in its Allowance Tracking System compliance sub-account to cover its SO_2 emissions for the year. (For NO_x, the emissions limitation would be the applicable limitation specified in 40 CFR Part 76, and each permit application would have to identify the type of boiler involved so that the applicable 40 CFR Part 76 NO_x limitation would be clear).

If an affected unit planned to comply with the Acid Rain program SO_2 or NO_x standard compliance requirements without any special exceptions, a simple check-box on the permit application

would indicate this choice. However, for affected units relying on one or more of the compliance options for SO_2 or NO_x authorized by the Act, a proposed compliance plan using the appropriate form for the option or options chosen would have to be included with the permit application package. Upon approval, the unit-specific compliance plans would be attached to the permit for that source and, depending on the option approved, would modify the program's standard requirements. The Agency requests comments, however, on whether it would be more appropriate to specify the terms of all unit-specific compliance plans in the permit as alternative operating scenarios, or whether the approved compliance plans should as proposed today be attached and incorporated into the permit by reference. In either case, the legally applicable requirements the source would be subject to would be the same. For example, in either case, the source would be able to activate a conditionally approved compliance option (or operating scenario) by providing notice to the permitting authority, using the administrative permit amendment procedures of Section 72.303, as discussed below. However, by specifying the terms of the "operating scenarios" in the permit, all of the requirements applicable to a source would be articulated in one document, as compared to the two-document approach proposed today. Under today's proposal, however, those requirements more likely to undergo numerous revisions during the course of a permit's term, i.e., the unit-specific compliance options, will be contained in the separate compliance plan proposed by the source, and approved by the permitting authority and incorporated by reference into the permit.

The permit revision procedures proposed in Subpart J of today's proposal, as they apply to compliance plans, are also designed to increase the flexibility for the compliance option provisions of the Act. A source would be able to conditionally propose several compliance options for each affected unit for approval when it submitted its permit application. A conditionally approved option would not become effective unless activated by the source. Activation of an option that was previously conditionally approved could, thus, be accomplished by a simple notice process as an administrative amendment to the permit. Because the various compliance options are subject to specific statutory requirements and limitations, today's proposal would specify rules for activating options as appropriate and necessary. Any compliance option not included in the original permit application, which was proposed after permit issuance, could be added by revising the permit pursuant to Subpart J.

1. Multi-Unit Requirements. The rule proposes that the permitting authority can approve multi-unit compliance plans where the units are located at different sources. In such cases, the designated representative of each source would have to certify the compliance plan, a copy of which would have to be included in the permit application for each source. This provision is intended to provide utilities with flexibility in

determining least-cost methods of compliance, and to allow compliance plans that are consistent, for example, with pre-existing power pooling arrangements. Restricting compliance plans to one source would greatly interfere with this flexibility. The Agency requests comments on this approach.

2. Phase I Substitution Plans. Subsections 404(b) and (c) of the Act authorize any source with a Phase I Appendix A affected unit to propose in its Acid Rain compliance plan a reassignment of the affected unit's Phase I sulfur dioxide emissions reduction requirements, in whole or in part, to one or more existing Phase II, Appendix B units. The designated substitution unit would, in turn, become a Phase I unit. The intent of this provision is to give any Appendix A Phase I unit the flexibility to reassign its Phase I emissions reductions obligations by allowing an Appendix B unit to achieve reductions in its place, above and beyond what the Phase II unit would otherwise be required to achieve. It also would provide Phase II Appendix B units the opportunity to participate in the Acid Rain program allowance system early, and to benefit from the economies associated with the allocation and banking of allowances.

The following example illustrates how a substitution plan might work: A Phase I unit emits 100,000 tons of SO_2 a year, but is only entitled to receive 50,000 allowances to cover its annual SO_2 emissions. It, therefore, needs 50,000 tons of extra allowances. Under a substitution plan, a utility may meet its allowance obligations by reducing emissions from one or more Appendix B unit by a total of 50,000 tons from its 1985 level of emissions and transfer the Appendix B unit's allowances to the Appendix A unit.

(a) *Applicable Units/Exclusions.* Only existing Phase II units (listed in Appendix B) would be eligible to participate in substitution plans with Phase I units. This requirement would rule out units that are not affected units under Title IV and new units. The Agency considered whether sources not affected under Title IV should be allowed to become substitution units. The Agency believes that no added flexibility would be achieved by allowing sources not subject to Title IV to be designated as substitution units since such sources would be able to participate in the allowance program as opt-in units pursuant to Section 410 of the Act and 40 CFR Part 74. In addition, such an interpretation would undermine the intent of Congress to encourage early reductions at existing Phase II units under Section 404(b) and (c), as well as the specific limitations imposed by Congress on sources not otherwise governed by Title IV which elect to participate in the Acid Rain allowance system under Section 410 of the Act. For example, Section 410 opt-in sources may not transfer allowances freed-up by reducing utilization below their baseline.

The Agency also proposes to exclude new units from the substitution provision because, with limited exceptions, the Act prohibits the allocation of allowances to new units. Thus, a

rule authorizing allocations of allowances to new units under substitution plans would dilute the emissions reductions the Act intended to be achieved during Phase I. Nor do new units have the historical operating data to calculate the reductions that would be required under a substitution plan. Such units were clearly not intended to be eligible to participate in the Acid Rain program under the substitution provision.

(b) *"Common Control" Requirement.* The proposed requirement in Section 72.41(a) that the substitution unit be under the "common control" of the same designated representative as the Appendix A unit for which the proposed plan is submitted is based on the statutory requirement that the units be under the control of the same "owner or operator". This is an exception to the general rule discussed above that units at more than one source could be designated in a single compliance plan signed by multiple designated representatives. The statutory language for substitution plans would prohibit this flexibility. By proposing that a single designated representative be deemed to fulfill the requirement of "common owner or operator", the Agency seeks to allow greater flexibility for sources while at the same time ensuring that the statutory concern regarding accountability will be met. As discussed above under Subpart B, an alternative reading of the statutory language would require that the units be under the control of the same owner or operator, and would hold that a common designated representative alone is inadequate unless that person is <u>also</u> an owner or operator. The Agency solicits comments on the approach taken in the proposed regulation, and on the alternative reading of the statute.

Section 72.41(e) specifies the requirements and prohibitions that would apply to substitution plans, including the requirement that the designated representative and the owners and operators of the original and substitution unit will share the responsibility for ensuring compliance with the plan by each unit, and liability for any violation. The basis for this provision is discussed in the general section on compliance plans and in the section on designated representatives.

(c) *Conditions of Plan.* The Act requires that the substitution plan ensure that the same or greater emissions reductions be achieved as would have been required to be achieved without the plan. The rule proposes step-by-step instructions concerning what would be needed in a substitution plan demonstration to meet this requirement. These proposed demonstration requirements are based on the provisions of Section 404(b) of the Act concerning what is required to be included in each proposed substitution plan. The proposal also specifies that the Administrator would allocate allowances to the Appendix A and substitution unit(s) in accordance with the approved substitution plan and that, thereafter, only the standard quarterly and end-of-year compliance certification reports would be necessary. The proposed reporting requirements have been kept to a minimum because the Agency believes that, once a substitution plan is approved and the appropriate number of

allowances are allocated for the year, the integrity of the plan is ensured.

Consistent with Section 404(b)(5), today's proposal assumes that when determining the reductions that would have been achieved without the substitution plan, the reductions that would have occurred at the Appendix A unit must be considered, as well as the reductions that would have been required of the Appendix B unit where its Federally enforceable applicable SO_2 emissions limitation (e.g., SIP limit) was made more stringent after 1985. Voluntary reductions at the Appendix B unit above and beyond what it was required to do under applicable Federally enforceable law would not be included in the calculation of reductions without the plan, since that would unnecessarily penalize and discourage early reductions. The Appendix A unit's required reductions would be calculated based on the difference between the unit's 1985 emissions rate multiplied by the unit's baseline and the unit's basic allowance allocations for Phase I (as authorized by Table A of the Act or as adjusted pursuant to Section 403. See, Appendix A). The Appendix B unit's reductions would be equal to the difference between its baseline multiplied by the lesser of its actual or allowable 1985 emissions rate and its baseline multiplied by the more stringent allowable rate at the time it was designated for substitution.

Alternatively, the Agency asks for comment as to whether the reductions that would have been achieved by the substitution unit in the absence of the plan should be deemed to be zero. Such an approach would be based on the fact that Appendix B units are not required by Title IV to achieve emissions reductions during Phase I. It could, thus, be argued that the rule, as proposed, would increase the overall Phase I reductions contemplated by the Act.

The Agency considered whether to calculate required reductions and allowance allocations for the substitute unit based on the substitution unit's current utilization and emissions rather than on the unit's baseline (i.e., 1985 through 1987) utilization and emissions. Such an approach would provide an additional incentive for substitution plans by accounting for growth. The Agency decided against this approach, however, for several reasons. First, neither Section 404(b) or (c) authorize growth credits. Second, the statutory authorities for calculating allowance allocations for Phase II are based on each unit's baseline utilization. Similarly, the only other provision under which Phase II units can become affected units during Phase I, Section 408(c)(1)(B) of the Act (reduced utilization), does not authorize allocations for growth allowances. Thus, even though the program's 8.95 million allowance cap does not begin during Phase I, it is apparent that Congress intended the substitution provisions to encourage and reward early controls, not to be used as a vehicle for inflating the number of allowances available on the market during Phase I of the program.

(d) *Termination of Substitution Plans.* The proposed rule allows units subject to substitution plans to terminate such

plans and to de-designate substitution units in a plan. As a pre-condition of such termination or de-designation, the affected substitution units must surrender allowances equal to those allocated pursuant to the substitution plan. This is to ensure that future-year allowances, equal to those allocated to the Appendix A and substitution unit under the presumption that the substitution unit would continue to be affected for the remainder of the Phase, cannot be used in future years when the de-designated substitution unit is no longer affected and no longer making verified emissions reductions. To effectuate the surrender of such allowances, the rule requires that before the substitution plan can be terminated or a substitution unit de-designated, the substitution unit's Allowance Tracking System subaccounts must include allowances equivalent in number and compliance use date to those allocated to the substitution or original Phase I unit (above the original unit's basic allocations) pursuant to the substitution plan for the remaining years of Phase I. When the plan is terminated, the Agency will deduct the allowances from the substitution unit's account.

3. Phase I Extension Plans. Section 72.42 of the rule would implement the authority in Section 404(d) of the Act, which provides that Phase I units may apply for a two-year extension of the Phase I compliance deadline of January 1, 1995, provided that the units install 90% sulfur dioxide removal technology or transfer their emissions reduction obligations to a unit or units that install such technology. (See, Section 72.2 for definitions of "qualifying Phase I technology", "transfer unit" and "control unit".) The Act provides that applications for Phase I extensions be acted upon by the Administrator in the "order of receipt". A limited reserve of up to 3.5 million allowances is authorized in Title IV to provide units that apply early enough and are granted Phase I extensions the extra allowances they will need to cover their sulfur dioxide emissions during the extension period.[2] The unit which installs the 90% control technology ("control unit") would also be eligible for additional allowance awards from this reserve for the three years after the extension period (1997-1999). These additional allowances would be provided to the extent the control technology reduces emissions at the unit beyond the standard Phase II emissions limitation of 1.2 lbs/mmBtu. (See, Section 404(d)(4)(c))

Section 404(d) was included in the Act to reduce the impact of the Acid Rain emissions reduction program on employment in high-sulfur coal mining communities, and to defray the compliance

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[2] A unit granted an "extension" under Section 404(d) is not exempted by Title IV from the requirement to prevent emissions of sulfur dioxide in excess of the allowances held in the unit's Allowance Tracking System account. Section 404(d) is, thus, better understood as authorizing a higher sulfur dioxide emissions limitation (and more allowances) for a two-year period, rather than an "extension" of the compliance date.

costs and consequent electricity rate increases that would otherwise be charged by some of the Phase I utilities currently using high-sulfur coal (See statement of Senator Baucus, Congressional Record, October 27, 1990, S 16981). The Agency considered these fundamental intentions in its interpretation of the final statutory language, and has interpreted Section 404(d) to the extent consistent with the statutory authority, to ensure that the reserve is not unnecessarily depleted. In addition, as is discussed further below, the Agency is proposing procedures to expedite the conditional award of allowances from the reserve in order to maximize the opportunity for sources to participate in the program.

(a) *Applicable Units.* Section 72.42(a) of the proposed rule states that the Phase I extension option may apply to: (1) all Appendix A units; and (2) Appendix B units used as control units and designated as affected units during Phase I as a result of their inclusion in either a substitution plan or a reduced utilization plan.

Consistent with the Act, the Agency proposes that new units not be eligible for inclusion in Phase I extension plans. New units would be required to meet strict SO_2 control requirements under other provisions of the Act. The Agency believes that allowing new units to benefit from achieving the level of control they would be required by law to meet anyway would deplete the reserve at the expense of Phase I affected units, and would be inconsistent with the intent of the Phase I extension provisions. The Agency also proposes not to allow opt-in units to apply for extension allowances for similar reasons, since they are not required to become affected units during Phase I.

The Agency has interpreted the statutory requirement in Section 404(d)(1) that the control unit "employ" a qualifying Phase I technology to mean that any Phase I Appendix A unit that installs and operates qualifying technology on or after enactment up until the end of the extension period on December 31, 1996, can apply for extension allowances. A unit that installed qualifying Phase I technology before enactment would not be eligible to apply for the extension, since sources installing controls before enactment clearly did not do so to comply with Title IV. Expanding the potential pool of applicants in this way would deplete the reserve and restrict the number of controlled units that would be granted extensions.

EPA considered whether to restrict eligibility for reserve allowances to only those units installing qualifying technology during the 1995 and 1996 extension period. This interpretation was rejected because it would penalize those utilities that controlled their units early. Moreover, had Congress intended to fully exclude units controlled before 1995, they could have clearly stated as much.

(b) *Transfer Unit Limitations.* The rule proposes conditions which would govern the relationship between a unit which installs qualifying Phase I control technology and Appendix

A units which transfer their emissions reduction obligations to that unit. One condition would prohibit the control unit from being oversubscribed. In this way, the Appendix A transfer units could not receive more extension allowances during 1995 and 1996 than the tonnage of reductions that would be achieved by the control unit below its basic allowance allocation by installing 90% control technology. For example, if a control unit would receive 50,000 allowances during each year of Phase I and 90% control of the unit would reduce its emissions to 10,000 tons per year, no more than 40,000 allowances could be allocated from the reserve to transfer unit(s) for 1995 and 1996 (i.e., the difference between the control unit's basic allocations and the unit's emissions assuming 90% control), even if the transfer unit(s) needed more allowances to cover actual emissions during the extension period. This limitation is to ensure that the reserve would not be depleted by units that were not installing controls. The Agency proposes this requirement because, without it, a utility could draw an unlimited number of allowances from the reserve in 1995 and 1996. The proposal also prohibits transfer units from transferring their same emissions reduction obligations to more than one control unit. Transfer units may be changed at any time prior to January 1, 1995, provided that no additional allowances would be available under a plan as a result of such a revision.

(c) *Control Unit Limitations.* The Agency proposes that each application for a Phase I extension may specify more than one control unit, provided that all control units included in the proposed plan are located at the same source. Allowing control units from more than one source to be included in one application would tend to give the largest utilities an undue advantage to draw-down large numbers of allowances from the reserve should that application be treated ahead of others. Requiring a separate application for each source would, thus, help ensure a more equitable distribution of the reserve. There are, however, significant reasons for allowing applications with more than one control unit at a source. For example, a source may be planning to treat the emissions from all its units with one Qualifying Phase I Technology. Such a source might only be able to justify continued use of high sulfur coal if all its units had high efficiency controls installed. The Agency requests comment on this aspect of today's proposal. Control units may be dropped from a plan at any time prior to 1995. New control units could not, however, be added or substituted in.

(d) *Contents of Proposed Phase I Extension Plan.* Each proposed Phase I Extension plan would include a copy of an executed contract for the design and construction of qualifying Phase I technology as required in Section 404(d)(1)(B) of the Act. The Agency considered whether to provide an exemption from this requirement for units located in States where state law requires the unit to install a scrubber. The Agency decided not to allow such an exemption for several reasons. First, the statutory language explicitly requires a contract. Second, such

an exemption could provide certain units with an undue advantage in obtaining the Phase I Extension reserve allowances because they would not be delayed in submitting an application by the requirement to negotiate a binding contract. Finally, the Agency does not want to encourage such special interest legislation.

In Part 72.42(e) the Agency proposes specifications for the two parameters used to determine the number of allowances allocated to each Phase I Extension unit from the Phase I extension reserve. The average annual emissions (in tons per year) for calendar years 1988 and 1989 as required by Section 404(d)(4)(A) and (B) of the Act would be calculated using information reported on EIA Form 767 and as listed in Appendices A and B of this part for those years or the most stringent Federally enforceable allowable emissions limitation for those years, whichever is less.[3] The most stringent Federally enforceable allowable emissions limitation would be calculated using the annualization factors specified in the National Allowance Data Base proposal (56 FR 33278, Friday, July 19, 1991). (These will be published in final at 40 CFR Part 73 at a later date.)

Part 72.42(e) also provides that projected 1995 and 1996 emissions would be calculated using (A) projected utilization as reported on EIA form 767 filed in the year in which the Phase I extension is made, and (B) the lesser of the most stringent Federally enforceable emissions limitation or the unit's actual projected emissions at the time of application.

The Agency considered whether to allow a procedure for sources to petition for adjustments of these information points, but believes that such a procedure is not warranted for several reasons. First, the Phase I Extension is voluntary. If a utility finds that it is not favorable to apply for a Phase I Extension, it can chose another compliance option. Second, the information is historical, actual data reported by the utility itself and the statute does not provide for adjustment. (Cf. Section 403). Third, the Agency is attempting to respond to industry's need for certainty at an early date regarding allocation of allowances from the Phase I Extension reserve. Allowing an opportunity for adjustments to be made to essential historical data would delay certainty. However, some industry concern was raised about the need for an adjustment to the emissions data for narrowly defined situations such as a forced outage during 1988 and 1989. The Agency requests comment on the

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[3] If the data for 1988 or 1989 tons of SO_2 is missing from Appendix A or B (missing data is represented by a "-", not by a "0"), for any unit, the EIA Form 767 may be refiled by the source for the missing year. EPA will accept any such data from EIA. If the unit is not covered by Form 767, EPA will calculate the tons per year for 1988 or 1989 upon receipt of adequate documentation. EPA invites comment on how to calculate missing data.

appropriateness of allowing an adjustment in the limited situations where a forced outage occurred.

To implement Section 404(d)(4)(A) and (B) of the Act, today's proposal allows for awards of Phase I Extension reserve allowances to control units in 1995 and 1996 based on each unit's projected uncontrolled emissions for those years. This is because the authority to award reserve allowances for the extension period is based on the assumption that such allowances are needed to cover operations at control units before the controls are installed. However, under today's proposal even if a control unit had an operational scrubber in place by 1995, it would receive reserve allowances in 1995 and 1996 as if it were not scrubbing. An alternative interpretation of the statutory language of Section 404(d)(4)(A) and (B) would allow awards of reserve allowances to each control unit based on its projected uncontrolled 1995 emissions only if the scrubber was <u>not</u> actually operational in 1995. If the scrubber were operational, the unit would receive allowances from the reserve based on the absolute (i.e., positive) difference between 2.5 lbs/mmBtu x baseline divided by 2000) and the unit's projected <u>controlled</u> emissions (at 90%). The Agency requests comment on which of these two interpretations would be most appropriate to adopt.

(e) *90% Control Technology Demonstrations.* EPA considered several methods for demonstrating a technology's capability to achieve 90% control for SO_2. For example, EPA considered whether a designated representative should provide detailed information on technical parameters of the equipment. Ultimately, however, the Agency believes that a basic demonstration of the capabilities of the technology is adequate and will ensure more expeditious processing of extension applications. This is because at an estimated market price of $500 an allowance, sources will have sufficient incentive to achieve, if not exceed, 90% control efficiency. Thus, today's proposal would require that the plan include a basic description of the technology, the executed design engineering and construction contract for the unit installing the technology, and a vendor guarantee that the technology is designed to achieve or exceed 90% control efficiency at expected ranges of fuel type and operating conditions.

There are several reasons for relying on this approach. First, Section 404(d)(7) provides that after January 1, 1997 an allowance is required to be deducted from each transfer or control unit's Acid Rain Allowance Tracking System compliance subaccount for each ton of SO_2 emitted by the unit in excess of the annual tonnage limitation specified in their extension plan. This deduction of allowances is in addition to any excess emissions offsets required under Section 411. (See, discussion of 40 CFR Part 77, below.) The Agency's interpretation of this provision is that the annual tonnage limitation specified in a Phase I extension plan would not only determine the allowances which would be awarded to the unit from the reserve, but would

represent a cap on the allowable annual tons of SO_2 which could be emitted by the named control and transfer units. Thus, each unit subject to a Phase I extension plan would pursuant to Section 72.42(g), have allowances deducted to the extent it exceeded the limitation specified in its plan even if it had allowances in its Allowance Tracking System account to cover all its emissions for the year. EPA believes that Congress intended this cap on Phase I extension units to serve as an assurance that the 90% control requirement would be met, and that both transfer and control units would abide by the annual tonnage limitations specified in the Phase I extension plan.

The Agency proposes that the 90% control obligation would apply through the end of Phase I. Utilities will receive substantial financial benefits from the bonus allowances allocated for a Phase I extension based upon the annual tonnage limitations specified in the extension plans. Because the Phase I extension reserve may be oversubscribed, the award of extension allowances to one unit is likely to mean that another otherwise eligible unit will not receive any extension allowances. Thus, as a matter of equity, it would be appropriate that units be required to maintain the levels of SO_2 control and emissions reductions upon which their bonus allowance allocations were based past Phase I.

The Agency has included in today's proposal a requirement that sources demonstrate achievement of 90% control through a start-up, and an annual performance test during each year of Phase I. This procedure would verify whether the limits specified in the plan are actually the result of the unit's use of 90% control technology. The test methodology for making the demonstration is proposed today in 40 CFR Part 75. (It should be noted that the test methodology specified in 40 CFR Part 75 would only apply to post-combustion control technologies. It would not apply to units that achieved 90% control with pre-combustion and combustion technologies, such as coal cleaning or repowering technologies. In such instances the Agency proposes that sources be required to demonstrate 90% control using a methodology proposed by the source and approved by the Administrator on a case-by-case basis. The unit would not obtain the conditionally allocated reserve allowances after it commenced operation of the controls, until 90% removal efficiency was demonstrated by a start-up test. Thereafter, if the annual performance test did not demonstrate 90% removal efficiency, the conditionally allocated reserve allowances for that year would be withheld from the units Allowance Tracking System account. The Agency requests comment on the 90% performance test provision. In particular, the Agency requests comment on whether the annual test should be a 30-day test which, if failed in the first instance could be repeated until 90% control can be demonstrated, or whether control units should, as proposed today, be required to demonstrate 90% control on an annual average basis, using continuous inlet monitor data collected throughout the year.

(f) *Determining "Order of Receipt" -- Early Ranking Procedure.* Section 72.42(c) and Subpart L of today's proposal (discussed further below) addresses the statutory mandate that submissions for Phase I extensions be acted on by the Administrator "in order of receipt", as well as the need of the regulated community to know whether they will be eligible for extension allowances as early as possible. Because of the economic benefits a source would derive from a Phase I extension, the allowance reserve of up to 3.5 million tons is expected to be oversubscribed. The Agency consequently believes that many sources are likely to apply for the extension allowances on the first day for submitting applications authorized by the rule. It may, therefore, be difficult to determine the "order of receipt" by relying exclusively on the U.S. postal system. Because of the problems inherent in implementing this provision, the Agency proposes a procedure at Subpart L of the rule allowing applicants the option of seeking early rankings of Phase I Extension applications, conditioned on submission by applicants of complete and approvable permit applications by the Section 408 Phase I deadline of February 15, 1993. The Early Ranking procedure is contained in a separate subpart of today's proposal in order to expedite rulemaking. (The Agency believes that going to an expedited final rulemaking on critical provisions, i.e., Section 72.42, Subparts A, B, and L, may be possible if no significant adverse comment is received on those portions of the rule.) The Agency is proposing the Early Ranking procedure in order to provide sources with a reasonable idea, at an early date, of whether they will be likely to qualify for and receive allowances under Section 72.42 for Phase I extensions. Information available to EPA indicates that it may take up to three years to design and install 90% control technology. Utilities, thus, need this assurance as early as possible in order to be able to install controls at their Phase I units before January 1, 1997.

In the event comment on this and other provisions of today's proposal central to Phase I extensions (e.g., Subparts A, B, L and substitution plans) is favorable, the Agency proposes to accelerate a portion of this rulemaking to implement the early ranking procedure as soon as possible. Significant adverse comment would make this less likely.

(g) ***Prohibition on Termination of Approved Phase I Extension Plans.*** Generally today's proposal authorizes sources to terminate compliance options using the Subpart J permit revision procedures. This general flexibility would not, however, apply in the case of approved Phase I Extension plans. The Agency believes that due to the competition for the limited Phase I Extension allowance reserve, sources should be subject to a firm requirement to go forward with installation of qualifying Phase I control technology once their proposed plan is approved. Sources may, however, elect to withdraw their plan before it is approved by the Administrator since they would not have benefitted from the award of any reserve allowances.

4. Phase I Reduced Utilization Plans and Under-utilization Accounting Requirements.

(a) *Background.* Utilities with units subject to emissions limitations in Phase I of the Acid Rain program may choose among a number of compliance strategies. One such strategy is to reduce utilization at higher emitting units, and to replace this generation through increased utilization of low-emitting units.[4] In enacting Title IV, however, Congress recognized that during Phase I of the Acid Rain program, reductions in emissions attributable to a decrease in utilization of Phase I affected units below their baseline could prevent full achievement of expected emissions reductions if the generation were shifted to non-affected units.[5] This is because such load shifting would result in a decrease in emissions and concomitant creation of excess allowances at the Phase I unit, despite the fact that there was an emissions increase at the non-affected unit providing compensating generation.

At the same time, Congress recognized that in order to ensure electric reliability, it was necessary to accommodate temporary changes in emissions (and shifts in utilization) resulting from decisions related to normal dispatching procedures and responses to emergencies. Because such load shifting between affected and non-affected units, whether planned or unplanned, could cut the actual aggregate emissions reductions expected during Phase I by as much as 50% a year, the Act includes two provisions, Section 408(c)(1)(B) and Section 403(d), to address these related but distinct situations. Both provisions give EPA the authority to require an allowance accounting for increases in emissions at otherwise non-affected units providing compensating generation.

Throughout the rule and preamble the term "under-utilization" is used to refer to any decrease in utilization at a Phase I unit below its baseline.[6] The term "reduced utilization"

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[4] The inherent fungibility of allowances and emissions reflects Congress' intent to enable utilities to utilize least-emissions dispatching procedures, in order to minimize their compliance costs. (See, Sen. Rept. No. 228, 101st Cong., 1st Sess., pp. 316, 319 (1989), House Rept. No. 490, 101st Cong., 2nd Sess. p. 373 (1990).)

[5] E.g. Phase II Appendix B or new units.

[6] "Baseline" refers to the unit's annual average 1985 through 1987 heat input or utilization measured in mmBtu. With certain specified exceptions, the Acid Rain program allowance allocation scheme established in Title IV is based on the unit's baseline utilization. Generally speaking, yearly allowance allocations are calculated by multiplying the baseline for a unit by the presumptive emissions limitation for the Phase. It is important to note that neither the rule nor the statutory provisions are

is used to refer only to under-utilization subject to the planning requirements of Section 408(c)(1)(B) of the Act.

(i) Section 408(c)(1)(B). Under Section 408(c)(1)(B), the designated representative, owners, and operators of any Phase I affected unit planning to achieve Phase I emissions limitation requirements by reducing the unit's utilization below its baseline or shutting the unit down, and shifting generation to a unit that is not otherwise affected during Phase I, are required to designate the otherwise unaffected unit as a Phase I compensating unit. The designated compensating unit becomes a Phase I affected unit subject to the Phase I emissions limitation, permitting, monitoring and excess emissions requirements of the Act. In addition, the designated compensating unit is allocated allowances by the Administrator approximately equal to its 1985 emissions, pursuant to a formula set out in Section 408(c)(1)(B).[7]

In this way, the Act allows shifts in generation from a Phase I unit to a designated compensating unit, while ensuring that emissions increases at the compensating unit are accounted for in the allowance system. In addition, all allowance savings resulting from the reduced utilization at the Phase I unit can be banked by the source, since these unused allowances will correspond to actual net reductions in SO_2 emissions for the year.

(ii) Section 403(d). Section 403(d)(2) provides, in relevant part:

> In order to insure electric reliability, regulations shall not prohibit or affect temporary increases and decreases in emissions within utility systems, power pools, or utilities entering into allowance pool agreements, that result from their operations, including emergencies and central dispatch, and such temporary emissions increases and decreases shall not require transfer of allowances among units nor shall it require recordation.

This language reflects Congressional intent to enable utilities to integrate compliance with their emissions limitation obligations with the normal operation of the nation's electric generation dispatch system. It specifically precludes EPA from issuing regulations that might hinder the ability of utilities to vary the utilization of individual units during the course of a year for energy reliability reasons according to traditional utility electricity dispatching practices.

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concerned about decreases in utilization at Phase I units that do not cause the unit's total utilization for a Phase I year to be less than its baseline.

[7] New units, having a zero baseline, would not receive any allowance under the formula.

Notwithstanding this goal of regulatory neutrality, however, Section 403(d)(2) also contains a requirement that utilities compensate at the end of the year for emissions resulting from generation load-shifting due to dispatching, including shifts from affected to non-affected units. Section 403(d)(2) goes on to provide, in relevant part, that:

> . . . [T]he total tonnage of emissions in any calendar year (calculated at the end thereof) from all units in such a utility system, power pool, or allowance pool agreements shall not exceed the total allowances for such units for the calendar year concerned.

In addition, Section 403(d)(1) requires EPA to promulgate regulations that provide for the "orderly and competitive functioning of the allowance system." EPA believes that an essential element of an "orderly and competitive" allowance system is that utilities not be allowed to bank allowances in the absence of actual reductions in emissions.

A system that permitted the banking of allowances without ensuring that corresponding emissions reductions took place in the year the allowances were banked would defeat the statutory intent to use allowances as the backbone of a national compliance system. While some banked allowances would reflect costs actually incurred by a utility to achieve actual emissions reductions, others would be banked notwithstanding the fact that actual emissions reductions had not been paid for or achieved. Thus, although cost-effective utility operations are encouraged, subsections (d)(1) and (2) together mandate that they not be achieved at the expense of required emissions reductions,[8] nor at the risk of undermining the integrity of the allowance system established under Title IV.

Consequently, EPA is faced with the task of ensuring the compatible achievement of two distinct policy objectives: first, the Phase I emissions reduction requirements must not be by-passed by load-shifting to unregulated units, and second, utilities must be permitted to continue to operate in an economic and reliable fashion. Accordingly, in addition to the specific planning requirements implementing Section 408(c)(1)(B), today's proposal includes an allowance accounting procedure, promulgated pursuant to Section 403(d) and set forth in Sections 72.402 and 72.409 of the rules, to address under-utilization and load-shifting that occurs incidental to dispatching or forced outages during Phase I.

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[8] Congress intended that Phase I emissions reductions be achieved not only on a unit-by-unit basis but on an aggregate basis as well. For example, section 404(a)(2) requires the Agency to establish an allowance reserve based on "the total tonnage of reductions in the emissions of SO_2 from all utility units in calendar year 1995 that will occur as a result of compliance with the emissions limitations requirements of this section."

To implement Section 403(d), the proposed rule would require that an allowance accounting be made at the end of each calendar year for any Phase I affected unit whose under-utilization due to dispatching or forced-outages resulted in emissions increases at non-Phase I affected units. The units that provided compensating generation for this purpose, and not for the purpose of a compliance plan meeting the Phase I emission limitation, would not have to be designated as Phase I affected compensating units. Allowances would, however, be deducted from the Phase I unit's account at the end of the year in an amount equal to the product of (A) the increment (in Btu's) of the unit's under-utilization multiplied by (B) the Btu-weighted average emissions rate for the year of the units providing compensating generation (after accounting for system-wide downturns, Phase I unit generation, and sulfur-free generation). Under-utilization would, thus, be accorded different regulatory treatment depending upon whether it occurred for the purpose of compliance planning under Phase I.[9]

In sum, EPA is proposing to limit the applicability of Section 408(c)(1)(B) to instances where utilities adopt reduced utilization as a method of compliance in order to afford utilities maximum flexibility in relying on economic dispatching and integrated compliance strategies. EPA is proposing under the authority in Section 403(d) to require that the designated representative of Phase I units that are under-utilized in any year for reasons other than compliance, and that shift generation to unaffected units, surrender allowances to account for the emissions increases at the unaffected units providing the compensating generation. In this way, allowance banking may not take place without corresponding emissions reductions.

The Agency believes that this approach best implements the express intent of Congress to establish a program that assures that Phase I emissions reductions are achieved, and the "orderly and competitive functioning of the allowance system" is preserved, without interfering with traditional utility dispatching operations.

(b) *Concerns Addressed by Limiting the Applicability of Section 408(c)(1)(B).* Today's proposal rejects an interpretation of Section 408(c)(1)(B) that would apply its provisions to <u>all</u> circumstances involving under-utilization and load-shifting. EPA believes that the appropriateness of the proposed limited applicability of Section 408(c)(1)(B) depends on the simultaneous

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[9] In developing today's proposal, the Agency rejected one interpretation that has been offered of Title IV, whereby no "retrospective" allowance accounting requirement would be imposed to account and compensate for under-utilization and corresponding shifts in generation that may occur as a result of forced outages or dispatching. EPA believes that an approach that ignored end-of-year accounting for shifts of generation in any year of Phase I that resulted in emission increases at non-affected units runs counter to the Agency's mandate under Section 403(d).

proposed implementation of its mandate under Section 403(d). Indeed, in the absence of the latter, EPA believes that it would be compelled to apply Section 408(c)(1)(B) to all circumstances involving under-utilization in order to carry out the statutory mandate of ensuring that required emissions reductions are achieved. As is explained further below, such an outcome is neither necessary nor desirable.

(i) Growth at Unaffected Units. EPA believes that, for purposes of ensuring the integrity of the Phase I emissions reduction program and of the allowance system, only those increased emissions at units not affected during Phase I resulting from shifts in generation from Phase I units are of concern. The balance of the emissions from units not affected during Phase I are not relevant, since those emissions were expected to occur and were accounted for when Congress established the Phase I emissions reduction portion of the Acid Rain program. Were the proposed rule to apply Section 408(c)(1)(B) in all instances of under-utilization, such that units providing compensating generation due to economic dispatching became affected units, far greater emissions reductions would occur in Phase I. Specifically, designated compensating units would be allocated allowances, pursuant to the statutory formula, in amounts equal to their mid-1980's utilization and emissions levels. These units would, in turn, be forced to obtain allowances to offset not only emissions occurring due to generation shifted from Phase I units, but also emissions resulting from demand growth between 1985 and 1995. Such a result is contrary to Congressional intent to accommodate growth in demand at Phase II units between 1985 and 2000. (See generally legislative history cited above; Sections 405(d), (e), (f), and (h) and 406 of the Act; House Rept., No. 952, 101st Cong., 2nd Sess. (1990), p. 343.)

(ii) Wholesale Power Arrangements. The proposed approach fully accommodates the unique problems faced by electric utility systems that routinely purchase power (as well as systems operating with low margins of unused capacity) and that may not be able to provide compensating generation from within their system and may be forced to buy additional power from outside their systems, for example, in the event of a forced outage. Sellers of power might be reluctant to sell power to purchasing systems if it meant that unaffected units providing the power would be subject to Phase I emissions limitation requirements under Section 408(c)(1)(B). Under today's approach to under-utilization, including the provisions proposed specifically for dealing with forced outages, a purchasing system could identify and account for emissions increases due to the compensating generation at another utility, by deducting allowances as provided in Section 72.409, without having to designate a compensating unit.

(iii) Operational flexibility. The Agency believes that the flexibility embodied in today's proposal is essential for large power pools and utility systems, which may vary generation

continuously at individual units based on economic dispatching procedures. These arrangements could continue, even if they resulted in incidental under-utilization, without the need for designating compensating units. Similarly, today's approach addresses the compliance problems that would otherwise be faced by utilities that may be unable to designate a compensating unit in the event of under-utilization caused by forced outages.

(c) *Distinguishing Between Section 408(c)(1)(B) and Section 403(d) Treatment.* The distinction between Section 408(c)(1)(B) and Section 403(d) is found in the language of Section 408(c)(1)(B), which states that it applies:

> [i]n the case of a compliance plan for an affected source under sections 404 and 407 for which the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit, . . .

Distinguishing between reduced utilization arising in the context of Section 408(c)(1)(B) and under-utilization under Section 403(d) will inevitably require a retrospective assessment of the reasons for, and circumstances surrounding, any under-utilization.

There are specific factors that would be dispositive of the applicability of Section 408(c)(1)(B) and Section 403(d). A unit would be treated as subject to Section 408(c)(1)(B) if the owners and operators of a Phase I affected unit institute a planned reduction in utilization below the unit's baseline in order to comply with the unit's Phase I emissions limitations.

By contrast, a showing that the net aggregate utilization of all Phase I units in a utility's system was equal to or greater than the aggregate baseline would excuse any under-utilization at a Phase I unit since all the under-utilization would be deemed to be treated as compensated for at those units. In addition, the demonstration of a system-wide downturn would excuse under-utilization to the extent the percentage under-utilization equals or is less than the percentage downturn. With regard to any excess of under-utilization above the level of the downturn, there would be a rebuttable presumption that Section 403(d) applies, and Section 408(c)(1)(B) would apply only if there is clear and convincing evidence that the planning requirements of Section 408(c)(1)(B) was violated. Under-utilization that is the result of a forced-outage would also be treated pursuant to the provisions of Section 403(d). In that regard, a showing that under-utilization was the result of a forced outage would clearly lead only to the applicability of the Section 403(d) allowance accounting.

Additionally, to the extent a unit can demonstrate that it had followed one or more of the options specified in its approved compliance plan and that, as of the allowance transfer deadline, the unit held allowances covering emissions that would have occurred in the absence of any reduced utilization, there would be a rebuttable presumption that Section 403(d) applies. Under such circumstances, Section 408(c)(1)(B) would apply only if

there is clear and convincing evidence that the planning requirements were violated.

In the absence of these dispositive cases, EPA would have to consider the full range of circumstances surrounding the specific case of reduced utilization or under-utilization. While no one factor would be dispositive, factors which EPA would consider as possible indications of the applicability of Section 408(c)(1)(B) include: a finding that there was a failure to implement additional emissions reduction strategies to comply with the Phase I emissions reduction requirements (in lieu of under-utilization as a compliance means); and a finding that a utility made a fundamental change in the Phase I unit's role within the system, such as shutting down the unit and replacing the generation with generation from a non-affected unit.[10] EPA considers the shutting down of a unit to be virtually dispositive that Section 408(c)(1)(B) applies, in the absence of compelling evidence to the contrary.

Factors that EPA would consider as possible indicators of the applicability of Section 403(d) include: a demonstration that the under-utilization was due to a change in the dispatch order because of increases in the relative generation costs at the unit to the extent such increases are unrelated to the benefits a utility might derive from the resulting banked allowances. For example, changes in the generation costs might reflect the installation of pollution control equipment at the unit or changes in fuel supply. The rule would also allow EPA to consider other relevant indicators demonstrated by the source. EPA requests public comment on indicators that should be considered to determine the applicability of Sections 403(d) and 408(c)(1)(B).

(d) *Specifics of Section 408(c)(1)(B) Reduced Utilization Plans and Section 403(d) Accounting.*

(i) Net Aggregate Phase I Utilization Threshold Test. Under the proposed rule, accounting for reduced or under-utilization and shifts in generation from a Phase I unit to unaffected units, would not be required under Section 408(c)(1)(B) or Section 403(d) unless there was a net aggregate reduction below the aggregate baseline at <u>all</u> Phase I units within a source's utility system. For example, if there are two Phase I units within a system, and one <u>decreases</u> its heat input to one million Btu's below its baseline, but the other <u>increases</u> its heat input by two million Btu's above baseline, then the Phase I units in the system will have a net <u>increase</u> in heat input of one million

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[10] Subject to a decision in the final rule on whether NO_x limits apply to designated compensating units. Another factor would be a finding that the utility had unaffected units that would have to meet a Phase I NO_x emissions limitation if they had been designated as compensating units. (<u>See</u> further discussion below).

Btu's, and the under-utilization at the first unit will not trigger requirements to account for shifts in generation.

The Agency believes this threshold test is appropriate because it accounts for totally permissible shifts in generation from one Phase I unit to another. Shifts between Phase I units do not warrant further accounting in the way that shifts between Phase I and Phase II units do, simply because all Phase I units are required to hold allowances to offset all of their emissions. Without such a threshold test, a Phase I unit might trigger accounting requirements if its heat input drops below baseline even if generation was shifted to another Phase I unit and the emissions increases were accounted for.

(ii) System-wide Sales Downturn Threshold Test. The proposed rule would allow under-utilization at a Phase I unit without requiring designation of a compensating unit to the extent that the reduction below baseline resulted from a system-wide decline in kilowatt hour sales for the year (as compared with the previous year) due, for example, to an economic downturn or unusual weather. (The "system", for the purpose of making such a showing, would be defined as the generating units controlled by the same utility operating company.) No allowance accounting or additional planning requirements would apply under Sections 408 or 403(d), in the event the percentage reduction below baseline was demonstrated to be less than or equal to the percentage system-wide sales decline. The Agency believes that this is a reasonable approach because in cases of system-wide declines in generation and purchases there would be no corresponding shifts of generation to unaffected units. Only in cases where a Phase I unit experienced reduced utilization of a percentage that exceeded the percentage of system-wide downturn in sales would a shift of generation to one or more unaffected units be indicated. For example, if a system's total sales dropped by 15 percent from the previous year, the Phase I unit's drop in utilization from the baseline would be excused up to 15 percent. EPA requests public comment on this approach.

(iii) Section 408(c)(1)(B) Reduced Utilization Plans.

(A) General Requirements. Under today's proposal, when reduced utilization is used as a planned compliance strategy the designated representative must file a reduced utilization plan with EPA, in accordance with Section 72.43. If the load is being shifted to an otherwise unaffected unit, the plan must designate the compensating unit. The designated compensating unit would become an affected unit for Phase I for all purposes. If the compensating unit designated in the plan is located at another source, the source would become an affected source and the designated representative for the source would be required to submit a Phase I permit application. EPA would allocate allowances to the designated compensating unit in an amount approximately equal to its 1985 emissions, pursuant to the statutory formula specified in Section 408(c)(1)(B).

(B) Sulfur-free Generation Plans. If the reduced utilization plan proposes to shift load to a generator that does

not emit SO_2 (e.g., a renewable energy generator), the proposed rule would require the designated representative to submit a Sulfur-free Generation Plan and make certain demonstrations and certifications to ensure that no SO_2 would be emitted.

(C) Energy Conservation and Improved Unit Efficiency Plans. Section 408(c)(1)(B) of the Act does not require the designation of a compensating unit when reduced utilization occurs at a Phase I unit as a result of a program of energy conservation or improved unit efficiency measures, since these cause decreases in utilization without any shifts of generation to unaffected units. To get credit for such measures, the proposed rule requires that energy conservation and improved unit efficiency programs be described in the unit's proposed compliance plan, and that kilowatt hour savings resulting from such measures be verified by an independent auditor, by the utility's State rate regulator or, for electric utilities not subject to the jurisdiction of a State utility rate regulatory authority, by the entity with utility rate regulatory authority for such utility. Both demand- and supply-side measures would be energy conservation measures for a demonstration of reduced utilization due to energy conservation. (Cf. The Conservation and Renewable Energy Reserve program in 40 CFR Part 73 of today's proposal.)

The proposed rule provides that any utility reducing utilization at a Phase I unit as a result of an approved energy conservation program would be required to verify its utility system's energy savings annually. In order to encourage the use of aggressive energy conservation programs the rule provides that all verified energy savings in a system resulting from such a program could be attributed to the affected unit. In addition, the rule provides that units may be credited with energy savings achieved by measures initiated between the baseline period and 1995. EPA proposes two methods for verification of reduced utilization due to energy conservation or improved unit efficiency: (1) using the EPA Conservation Verification Protocol of 40 CFR Part 73, Subpart F (scheduled to be published at a later date); or (2) by the State utility rate regulator, provided that only States that have adopted least-cost planning practices and net income neutrality rules for investments in energy conservation would be qualified to verify demand-side measures. (See further discussion of Part 73, Subpart F). EPA is not proposing to require the use of the EPA Conservation Verification Protocol in States with least-cost planning practices and net income neutrality rules since regulatory scrutiny in such States is likely to be rigorous.

EPA recognizes that it may be difficult for a utility to verify energy savings for the entire year within the 30-day deadline for submitting annual reports provided for in Subpart K. Thus, the rule proposes that the annual report would only be required to verify energy savings through the third quarter (September 30) of the calendar year. Based on this verification, the annual report would include an estimate of energy savings for

the fourth quarter. Verification of energy savings occurring during the fourth quarter would be due with the next quarterly report for the source, i.e., by April 1 of the following calendar year. If the verified energy savings for the fourth quarter were less than the preliminary estimate, the utility would be required to account for the compensating generation and emissions that represented the shortfall in expected energy savings. EPA requests comment in particular on any issues of timing raised by this approach to the verification of energy conservation and improved unit efficiency.

(D) Failure to Submit a Section 408 Plan. EPA is proposing that in cases where a Phase I unit's utilization fell in any calendar year below its baseline, and where such decreased utilization was not governed by an approved reduced utilization plan, and was the result of a compliance strategy that relied on such reduced utilization, the designated representative, owners, and operators of the unit would be held liable for violating the planning requirements of Section 408(c)(1)(B) if no reduced utilization plan were submitted. EPA proposes a three tiered approach to determine whether the reduced utilization planning requirement was violated in any one year.

Under the first tier, a Phase I unit with under-utilization would be deemed not to have violated the reduced utilization planning requirements of Section 408(c)(1)(B) to the extent its under-utilization during the year was: (a) accounted for by a reduced utilization plan (including an energy conservation, a boiler or generation efficiency improvement plan, or a sulfur-free generation plan); (b) offset by over-utilization at other Phase I units within the unit's system such that aggregate utilization for all the Phase I units within the system was at least equal to the aggregate baseline for these units; (c) equal to or less than the percentage of a system-wide downturn in sales (in Kwh); or (d) a result of a forced outage at the unit.

Under the second tier, it would be presumed that there is no violation of the Section 408(c)(1)(B) planning requirements to the extent the designated representative of the unit demonstrates that the unit was operated in accordance with an approved compliance plan with the result that the unit held sufficient allowances to cover sulfur dioxide emissions that would have occurred but for the under-utilization. In addition, where there was a system-wide downturn but the percentage of under-utilization exceeded the percentage of system-wide downturn, it would, nevertheless, be presumed that Section 408(c)(1)(B) is not violated. The rebuttable presumptions of this second tier would, however, be overcome by a finding, based on clear and convincing evidence, that the reduced utilization planning requirements were violated.

To the extent the above two tiers do not account for the total amount of under-utilization, EPA proposes to apply a third tier of indicators on a case-by-case basis to determine the applicability of Section 408(c)(1)(B). The indicators include, but are not limited to, (a) two indicators that the under-

utilization was not planned: (1) that the under-utilization resulted from changes in the unit's utility system dispatch order resulting from increases in the relative cost of generation at the unit (except to the extent that the change in dispatch order was a result of the savings resulting from banked allowances), and (2) that measures were taken at the unit to cut its emissions rate to 2.5 lbs/mmBtu or less (e.g., evidence of low-sulfur coal reserves on hand); and (b) two indicators that the planning requirement was violated: (1) whether the under-utilization was due to a fundamental change in the unit's role within the utility system (e.g., a total shutdown of the unit), and (2) whether the utility failed to implement any other compliance strategies.[11] In addition, the rule authorizes the Administrator to consider any other relevant information provided by the source, including the degree to which reduced utilization was used to meet the unit's emissions limitation requirements. EPA believes that this three-tiered approach will assist utilities in determining whether they are required to submit a plan pursuant to Section 72.43.

If EPA determines that the unit should have filed a reduced utilization plan, full compensation for the increased emissions at the compensating units would be required, and excess emissions penalties would be assessed pursuant to Section 411 and Part 77 of today's proposal. Finally, the designated representatives for the under-utilized and compensating units would be required to submit not later than the deadline for the annual compliance certification report (due January 30th of each year), a reduced utilization plan designating a compensating unit.

(E) Applicability of NO_x Requirements to Compensating Units Under Section 408(c)(1)(B) Reduced Utilization Plans. The Agency considered two opposing views regarding whether the Phase I NO_x emissions limitations must be met by otherwise unaffected units (e.g., Appendix B units) that are designated as compensating units in an approved reduced utilization plan. The proposed rule does not apply Phase I NO_x emissions limitations to compensating units. There are, however, textual arguments that can be made from the statutory language to support both views. EPA, therefore, requests public comment on this issue.

The relevant statutory language concerning this issue is in Sections 407(a) and 408(c)(1)(B) of the Act. Section 408(c)(1)(B) provides:

> The unit to be used for such compensating generation, which is not otherwise an affected unit under sections 404 and 407, shall be deemed an affected unit under section 404,

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[11] Subject to a determination in the final rule as to whether designated compensating units will be subject to NO_x limits. Another indicator is whether the utility had a reason to try to avoid the NO_x obligations that would have to be met by a compensating unit. (See further discussion below).

subject to all of the requirements for such units under this title, ...

In addition, Section 407(a) states:

> On the date that a coal-fired utility unit becomes an affected unit pursuant to sections 404, 405, 409, or on the date a unit subject to the provisions of section 404(d) [Phase I extensions] or 409(b) [repowering extensions] must meet the SO_2 reduction requirements, each such unit shall become an affected unit for purposes of this section and shall be subject to the emission limitations for nitrogen oxides set forth herein.

Under the first view, designated compensating units that were not otherwise subject to Phase I of the Acid Rain program would not be subject to the Section 407 NO_x emissions limitations. This view would be based on the belief that Congress was concerned primarily with SO_2 emissions reductions in Phase I, and was either not concerned with shifts in NO_x emissions to unregulated compensating units or thought that the effects of such shifts would be minimal. This view is supported by the phrase in Section 408(c)(1)(B) providing expressly that otherwise unaffected compensating units become affected "under section 404", but does not state that the units also become subject to Section 407. In addition, although Section 407(a) provides that a coal-fired utility unit becomes subject to the NO_x requirements on the date that it "becomes an affected unit pursuant to sections 404, . . .", Congress did not include Section 408(c)(1)(B) in the list of sections giving rise to NO_x applicability.

The same two statutory provisions can, however, also be read together as requiring otherwise unaffected compensating units to comply with the applicable limits. Since Section 408(c)(1)(B) states that compensating units become affected units "under section 404, subject to <u>all</u> of the requirements for such units under [Title IV]", the applicability of the NO_x limits to units when they become affected "pursuant to section 404" would include units designated as compensating units. This view would be based on the belief that Congress intended Section 408(c)(1)(B) to prevent the shift of not only SO_2 but also NO_x emissions to units not otherwise affected during Phase I. This view is further supported by the express references to Section 407 in Section 408(c)(1)(B).

Because of the difficulties in reconciling the conflicting inferences which can be drawn from the textual material, and particularly given the complexity of the regulatory scheme, the Agency must adopt a construction of the statute that "represents a reasonable accommodation of . . . competing interests," following "detailed and reasoned" consideration of the issues. Chevron, U.S.A. v. NRDC, 467 U.S. 837, 865 (1984). The Agency, therefore, asks for comment in order to judge the relative weight (and wisdom) of the two views based on consideration of the full rulemaking record.

(F) Termination of Compensating Unit Plans. The proposed rule allows units subject to compensating unit plans to terminate such plans and to de-designate compensating units in a plan. As a pre-condition of such termination or de-designation, the affected compensating units must surrender allowances equal to those allocated pursuant to the compensating unit plans. This is to ensure that future-year allowances, equal to those allocated to the compensating unit under the presumption that the unit would continue to be affected for the remainder of the Phase, cannot be used in future years when the de-designated compensating unit is no longer affected and no longer making verified emissions reductions. To effectuate the surrender of such allowances, the rule requires that before the reduced utilization plan can be terminated, or a compensating unit is de-designated, the compensating unit's Allowance Tracking System subaccounts must include allowances, equivalent in number and compliance use date, to those allocated pursuant to the compensating unit plan for the remaining years of Phase I. When the plan is terminated, the Agency will deduct the allowances from the compensating unit's account.

(iv) Section 403 Accounting. Generally. Today's proposal specifies that, pursuant to Section 403 of the Act, any Phase I unit that experiences utilization below its baseline as calculated at the end of the year would, subject to the threshold tests discussed above, have allowances deducted from its Allowance Tracking System account to account for the shifts in generation and consequent emissions increases at unaffected units. Of course, the very nature of the electric utility industry operating through international grids of intra- and inter-connections, as well as complex variations of business relationships, eludes precise definition of where compensating generation is in fact being provided. The formula proposed in today's rule would serve as a proxy for calculating the actual emissions resulting from load-shifting that would otherwise be unaccounted for.

The accounting procedure proposed in today's rule would be accomplished as follows. Pursuant to Subpart C of today's proposal the designated representative for each Phase I unit would include in the permit application information identifying the NERC region or subregion where the Phase I unit operates. This broadly identifies the universe of units which may provide compensating generation for a Phase I unit as a result of dispatching. EPA is requesting comment on the feasibility of assembling and processing the data required to calculate NERC region average emissions rates as of the end of the allowance transfer deadline. The Agency acknowledges that NERC regions and subregions contain a large number of units and a number of different utility operating companies. It may be difficult for individual utilities to coordinate and assemble the necessary data on emissions rates and utilization levels in a relatively short period of time. One approach under consideration is to allow utilities to use utilization and emissions data from the

four consecutive quarters running from September 1 of the previous year to September 1 of the year for which the compliance certification is being made. The Agency requests comment on this approach and on other approaches for facilitating the calculations of NERC region average emissions rates.

At the end of the year, pursuant to the annual reporting and compliance certification procedures in Section 72.409 of Subpart K, a utility would take the following steps to account for incidental under-utilization:[12]

First, the utility would determine whether any of its Phase I units had utilization below baseline. If not, no further accounting would be necessary.

Second, the utility would calculate whether it meets the threshold test for aggregate Phase I under-utilization, i.e., whether, when viewed collectively, the aggregate utilization for all of the utility's Phase I units was below an aggregate baseline for these units. If the aggregate utilization for the utility's Phase I units was equal to or greater than the aggregate baseline, no further accounting for under-utilization would be necessary.

Third, the utility would determine whether it meets the threshold test concerning system-wide sales downturn, i.e., the extent to which the percentage of under-utilization is matched by the percentage of system-wide downturn. For example, if a utility system has experienced a decline in kilowatt hour sales of 1% during the year, and each of the utility's under-utilized units has been under-utilized by less than or equal to 1% of its baseline, then no further accounting would be necessary for under-utilization.

Fourth, using the formulas specified in the rule the utility would determine how much under-utilization is unaccounted for at each unit after subtracting the effects of: (a) shifts of utilization to other Phase I units within the utility's system; (b) system-wide downturn in sales; (c) shifts of utilization to other Phase I units within the NERC region of which the utility is a part; and (d) under-utilization accounted for by an approved reduced utilization plan.

Fifth, if after the above four steps the utility determines that not all the under-utilization at the unit can be explained and accounted for, it would then determine the emissions rates at which it will calculate allowances to be deducted as provided in the rule. As proposed today, the utility would have a choice between two different approaches. The first approach is the NERC region or subregion average emissions rate. Under this option, the utility would calculate an average emissions rate based on

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[12] The term "incidental under-utilization" implies that the under-utilization was not due to a failure to plan. It also implies that the decrease is not accounted for using the net-aggregate Phase I utilization and system-wide downturn threshold tests.

all the units within its NERC region or subregion. The calculation provided for in today's proposal would weight each unit's emissions rate by the number of Btu's it utilized over baseline.[13]

The second approach is the system average emissions rate. Under this option, the utility would base its average emissions rate on units within its own system plus any other units outside of its system for which it can document specific amounts of generation. The utility would also have the option to use the NERC system average emissions rate for any portion of generation outside of its system that could not be tied to any specific unit.

In addition, the Agency considered other formulas for calculating average emissions rate of compensating generation. Under another less complex formula the Agency is considering, allowances would be deducted from the Phase I unit's Allowance Tracking System account equal to the Btu's the unit reduced below its baseline times the under-utilized Phase I unit's actual annual average emissions rate. This simplified formula would apply subject to a demonstration by the source that the compensating generation was actually provided at a different emissions rate. A variation of this formula would be to multiply the Btu's of under-utilization by 2.5 lbs/mmBtu, the presumptive Phase I emissions limitation.

Finally, the Agency considered but rejected an approach that would require each Phase I unit to include a list in its permit application of every other unit in its utility dispatch order, including any units used by other utilities that are relied on by the Phase I unit's utility to meet electricity generating obligations. The end of year accounting in the event of under-utilization would be based on the annual average emissions rate of those units. The Agency decided against such an approach since it would unnecessarily complicate and burden the initial permitting process.

(A) Treatment of NO_x. EPA is proposing that NO_x requirements would not have to be met by unaffected units providing compensating generation as a result of incidental shifts in generation not subject to Section 408(c)(1)(B), since Section 403(d) of the Act is only concerned with SO_2.

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[13] EPA requests comment on how to establish baselines for sulfur-free generators for purposes of this calculation. In addition, EPA requests comment on how to treat shifts in generation to facilities outside the United States. Today's rule would not require United States utilities to designate foreign compensating units or to account for under-utilization due to shifts in generation to sources outside the United States, including surrendering allowances for emissions increases resulting from such shifts.

(B) Treatment of Forced Outages. As mentioned above, reduced utilization and shifts in generation resulting from forced outages would also be subject to Section 72.409 compliance certification and allowance accounting procedures proposed today pursuant to Section 403(d). In the case of a forced outage, a designated representative would document that an outage was due to unavoidable circumstances. The rule would also require a demonstration that the utility took steps and/or continues to take steps to restore the unit to service as expeditiously as practicable.

(e) *Timing of Accounting Period.* EPA considered two approaches for accounting for reduced utilization: a one-year accounting period and a five-year accounting period. Under the one-year approach, proposed in the rule, accounting would be required at the end of each year of Phase I. Allowances would be surrendered to account for the actual emissions from increased utilization at unaffected units due to load-shifting from Phase I units during the year.

Under a five-year approach, utilities would average utilization at Phase I units over the five-year Phase I period. At the end of each year utilities would place allowances equivalent to any under-utilization in a special allowance escrow account. If utilization increased above baseline at any Phase I units in a system in a subsequent year, the escrowed allowances could be used to offset the increased emissions. At the end of the five-year period, the utility would be required to surrender banked allowances only for any net under-utilization at Phase I units. The five-year approach, however, focuses exclusively on Phase I unit utilization and would not account for increases in emissions at the unaffected units providing compensating generation in any given year. EPA believes that the objective of both Section 403(d) and Section 408(c)(1)(B) is to account for annual emissions, not just utilization. Under a five-year approach, allowances that would have to be deducted from a unit's account under the approach proposed today would be available to offset emissions. The environmental effects would plainly be adverse.

In addition, a five-year accounting period would be inconsistent with the annual allowance allocation and compliance demonstration requirements mandated by the Act. The five-year approach does not account for annual increases in SO_2 emissions due to reduced utilization and load-shifting.

Finally, as is noted above, utility systems would have the flexibility under the one-year approach proposed today to dispatch generation cost-effectively and to deal with forced outages. Thus, the Agency believes that today's proposal allows for changes in load and operating conditions at electric utility systems without diminishing the emissions reductions contemplated by the Act.

5. Phase II Repowering Extensions. Section 409 of the Act authorizes the Administrator to grant a four-year extension of

the Phase II emissions reduction deadline where a unit repowers with a qualified technology. In addition, under certain circumstances, an existing utility unit may qualify for the extension if it is to be shut down and replaced with a new unit located at a different site but using a qualified repowering technology.

(a) *Effect of Repowering Extension.* During the "repowering extension period", a unit satisfying the criteria for eligibility and meeting the procedural requirements for repowering will not be subject to the otherwise applicable emissions limitation requirements for SO_2 and NO_x but instead will be allocated allowances under Section 409(c)(1) of the Act, implemented at Section 72.44(f)(3). EPA today proposes that the repowering extension period begin on January 1, 2000 and end on the date on which the affected unit for which the extension has been granted will be removed from operation to install the repowering technology or will be permanently removed from service for replacement in accordance with Section 72.44(b)(2), but no later than December 31, 2003. Thus, the repowering extension period will be unit specific. EPA believes this interpretation is consistent with the allowance allocation scheme developed in Section 409(c). In particular, Section 409(c)(2) states that upon the date the unit is removed from operation, the unit will be subject to the emission limitations of Section 405 of the Act.

(b) *Prohibitions on Termination of Approved Repowering Extension Plans.* Generally, today's proposal authorizes sources to terminate compliance options using the Subpart J permit revision procedures. This general flexibility would not, however, apply in the case of approved repowering extension plans after Phase II begins. Specifically, units granted a repowering extension will have benefitted from the receipt of additional extension allowances, some of which were allocated to the units pursuant to a pro rata ratchet on the allocation for all other Phase II units. EPA believes that it would, therefore, be unfair to allow sources to terminate repowering extension plans after they have benefitted from the allocation of extension allowances. Approved repowering extension plans could, thus, be terminated only until December 31, 1999.

(c) *Treatment of Failed and Abandoned Repowering Project.* The proposal states that, if after construction and testing of a repowering technology a source determines that the repowering technology is infeasible, the source would not be in violation of the Act, provided it demonstrates that it had proceeded with the repowering project in good faith. However, the source would not be eligible for allocations of additional extension allowances beyond the four year extension period in such cases. This is pursuant to Section 409(b)(2) of the Act, which addresses situations in which a repowering technology fails to achieve desired emissions reductions and is economically or technically infeasible. EPA is proposing that in such cases, where (as provided in the Act) the designated representative demonstrates

that the technology has been properly constructed and tested, the source's failure would not be a violation of the Act and extension allowances would continue to be allocated for the remainder of the repowering extension period. Upon expiration of the repowering extension period, however, the Administrator would allocate allowances to the unit according to the unit's standard Phase II allocations pursuant to Section 405. EPA believes that this is an appropriate interpretation of Congressional intent for this provision because it avoids penalizing utilities that attempted to comply with Acid Rain requirements through the use of innovative or experimental technologies.

EPA considered several other interpretations of Section 409(b)(2). Under one approach the source would have to surrender the extension allowances or pay other penalties in cases of failed repowering projects. Such an approach would, however, be clearly contrary to the intent of Congress, which included Section 409(b)(2) in the Act to ensure that the use of nonconventional technologies would not increase utilities' exposure to non-compliance penalties.

EPA also considered whether it should continue to provide extension allowances beyond the four year extension period in the event of a failed repowering project. EPA rejected this interpretation because the allocation of extension allowances beyond December 31, 2003 is not expressly provided for in the Act. Moreover, providing extension allowances beyond the extension period provided for in the Act would increase SO_2 emissions above the levels that would otherwise be allowed annually during Phase II, thereby causing an additional, negative environmental impact. The Agency believes that the ability to buy allowances on the market gives utilities the flexibility and time to consider other technological options for meeting Phase II emissions limits, without the necessity for further extensions.

Finally, EPA considered whether extension allowances should be granted in cases where a utility decides <u>before</u> it has completed construction that a repowering technology is infeasible, and the Agency makes a determination that the utility has proceeded in good faith. Two scenarios relevant to this issue are possible: (1) A utility applies for and receives a repowering extension by December 31, 1997, but determines prior to beginning construction that the repowering technology is economically or technologically infeasible and abandons the project; (2) A utility successfully demonstrates preliminary engineering and existence of the required contracts prior to the January 1, 2000, deadline, and begins construction. However, the technology proves infeasible prior to the completion of construction.

In both cases it could be argued that a utility would be faced with little time to meet the Phase II emissions limitations. Thus, without the assurance of an extension few utilities would attempt repowering as a method of compliance.

Today's proposal, however, allows the extension where a repowering project is abandoned before construction is commenced. EPA is concerned that providing extensions in cases such as the first might lead to attempts to circumvent the Phase II emissions deadline by submitting repowering extension applications without a serious intent to repower. The second scenario is more difficult. EPA believes, however, that both scenarios are contrary to the intent of Congress. The Agency notes that although the original Senate bill (S. 1630) had no requirement that construction and testing of the repowering technology be completed, the repowering provision enacted by Congress included this language. Thus, EPA believes that Congress intended to preclude extensions where construction and testing were not completed. Nevertheless, the Agency requests comment on the issues raised by Scenario 2. Specifically, EPA is interested in the types of demonstrations or other requirements that might be implemented if extensions until December 31, 2003 were granted in such cases. EPA is particularly interested in requirements that would safeguard against frivolous applications and efforts to circumvent the Phase II emissions deadline.

(d) *Repowering Application Process.* The proposed rule provides for a two-tiered process by which a designated representative would apply for a repowering extension. The first tier of the repowering extension application process would involve submission of a repowering extension compliance plan to the permitting authority by January 1, 1996, the deadline for Phase II permit applications. The plan may be submitted for conditional approval. However, the designated representative would be required to notify the permitting authority by December 31, 1997 of his or her decision to activate or withdraw the proposed compliance plan. EPA believes that the ability to activate or withdraw the repowering proposal gives utilities the flexibility to reconsider repowering plans up until the December 31, 1997 deadline provided for in Section 409(a) of the Act.

The second tier would be conditional approval of the repowering technology, a petition for which would have to be submitted to EPA before June 1, 1997. This deadline allows EPA and DOE six-months to review the technology and make a determination regarding whether the technology conditionally qualifies for an extension. Without such a deadline, it would be difficult for EPA and DOE to review all proposals before the December 31, 1997, deadline for the permitting authority to approve or disapprove the Phase II permit applications. It is important that this deadline be met so EPA will have adequate time to revise and publish the Phase II allowance ratchet before the June 1, 1998 deadline specified in Section 403(a) of the Act. EPA believes it is in the interest of any source wishing to repower to submit repowering technology petitions as soon as possible to avoid possible delays in the review of petitions. The Agency requests comment on the June 1, 1997 deadline for submitting this petition.

(e) *Qualifying Repowering Technology.* Section 402(12), in relevant part, defines "repowering" as follows:

> replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990. . . .[14]

The definition thus provides for three major categories of repowering technologies: (1) technologies specifically listed in the statute; (2) derivatives of one or more of these listed technologies; and (3) technologies which: (a) are capable of controlling multiple combustion emissions simultaneously; (b) with improved boiler or generation efficiency; and (c) with significantly greater waste reduction than technologies in widespread commercial use as of the date of enactment of the Act (November 15, 1990).

(i) Proposed Approach.

In accordance with the language of the statutory definition of repowering, the proposed rule provides that a qualifying repowering technology must involve "replacement" of an existing boiler. The language of Section 402(12), though ambiguous in many significant respects, will not support an interpretation which fails to recognize that repowering requires use of an appropriate new technology instead of the existing boiler.

EPA considered whether the reference to boiler replacement in Section 402(12) could be read as referring to only the first category of technologies. However, such an approach would require reading the provision as if the recital of the three alternative technologies began immediately after the phrase "repowering means", rather than after the phrase "repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies:".

Such a reading is inconsistent with the structure of the provision, in which the colon, which is "used chiefly to direct attention to matter that follows (as a list, explanation, or quotation)", See Webster's Ninth New Collegiate Dictionary 266

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[14] The last sentence in the definition of "repowering" in Section 402(12) of the Act refers to a specific clean coal technology project in Tallahassee, Florida (Arvah B. Hopkins Station Unit 2 Circulating Fluidized-Bed Repowering Project) awarded November 30, 1990.

(1985), follows rather than precedes the reference to boiler replacement. Moreover, all three categories of technologies would be properly described as "the following clean coal technologies:".

While it is true that the list following the colon, like the phrase "the following clean coal technologies," could be read to refer exclusively to the seven named technologies (or to those technologies and their approved derivatives), such an interpretation would still fail to provide a satisfactory explanation of the grammatical structure of the provision. Either of these two readings would fail to explain how the technologies that, according to those readings, do not consider boiler replacement, relate to the term "repowering". In other words, if the concept of boiler replacement were removed from either the third category of technologies or from both the second and third categories, the provision would read, with respect to those categories:

> The term "repowering" means . . . a derivative of one or more of [the seven] technologies, and any other technology capable of [meeting the three performance criteria].

The difficulty with this reading is that "repowering," whatever the precise scope of its definition, clearly means doing something with a derivative technology or a multipollutant control technology, rather than simply those technologies themselves. Requiring boiler replacement for all three categories avoids this particular infirmity.

EPA also considered another textual argument that could be advanced to support an interpretation of Section 402(12) that boiler replacement is not required for the third category of technology, but it also is unpersuasive. It simply does not follow from the fact that the category of multipollutant control technologies alone has expressly enumerated performance criteria and that those criteria are meant to be the exclusive test for qualifying technologies of these types. Because the third category of technology was intended to encompass types of technologies which were unknown on the date of enactment (and thus, unlike the prior categories, not susceptible to being enumerated in the statute) that category would necessarily have to include explicit defining criteria, whether or not the boiler replacement criterion applied to it. By the same token, the fact that the latter two categories are subject to EPA approval in consultation with DOE does not imply that this is the only criterion applicable to them. Each is subject to additional criteria (i.e., the requirement of derivation in the case of the second category, and the three performance criteria in the case of the third category).

The pivotal phrase "replacement of an existing coal-fired boiler" is undefined in the statute, and its scope is not clearly delineated by its context. Some of the seven listed technologies may not require total boiler replacement, although all require such extensive changes to the boiler that they are tantamount to boiler replacement. Under the principle of ejusdem generis,

therefore, the Agency clearly has, at a minimum, ample discretion to treat as functional boiler replacement any changes broadly similar in scope to those involved in installing the seven named technologies. Such a definition would clearly represent the lower, not the upper, limit on the Agency's discretion to give meaning to the term "replacement". Accordingly, the statute confers on EPA the additional discretion to define boiler replacement in a functional manner that takes into account achievement of the specified performance criteria as well as the degree of changes to the boiler. By way of example, it should be noted that in the recently proposed WEPCO rule the Agency proposed to consider a unit to be "replaced" if it would "constitute a reconstructed unit within the meaning of 40 CFR 60.15." 56 FEDERAL REGISTER 27636 (June 14, 1991). 40 CFR 60.15 defines "reconstruction" as:

> the replacement of components of an existing facility 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 set forth in this part.

In short, because "Congress has not directly spoken to the precise question at issue," Chevron, U.S.A. v. NRDC, 467 U.S. 837, 842-43 (1984), EPA enjoys a significant measure of discretion to determine to what extent replacement of less than 100% of the parts of an existing boiler could be deemed replacement for purposes of Section 402(12).

In accordance with the above language EPA proposes to use the 40 CFR 60.15 test for "reconstruction" as general guidance in determining whether each individual application under Section 409 involves sufficient replacement to qualify for a repowering extension. The Agency seeks comment on this approach and also seeks comment on whether there are other alternative interpretations of "replacement" that are appropriate. In addition, the Agency solicits comment concerning whether, instead of issuing general guidance pertaining to the definition of replacement, the Agency should promulgate specific regulatory requirements concerning the definition of "replacement" applicable to all repowering extension applications.

Finally, EPA notes that utilities are free to use <u>any</u> technology to comply with Acid Rain program requirements within the regular time-frame for compliance with Phase II emissions limits, or to bank allowances and control emissions earlier or later than January 1, 2000. Failure to qualify for a repowering extension does not preclude a source from employing a clean coal technology. In fact, the underlying philosophy of Title IV is to encourage technological innovation by giving utilities the flexibility to choose the most cost-effective technology and schedule for meeting emissions limitations.

6. New Unit Plans. New units are defined in Section 402(10) of the Act as units which commenced commercial operation

on or after November 15, 1990. Such units are generally subject to the Acid Rain program during Phase II. The proposed rule would require new units to begin complying with the Phase II Acid Rain emissions reduction requirements upon "commencement of operation," i.e., when the unit begins emitting SO_2 and NO_x.

Although most new units which commence operation between enactment and 1995 will receive some allowances pursuant to Section 405(g) of the Act, new units which commence commercial operation after 1995 will receive no allocations. Rather they are required under Title IV to obtain allowances to cover their SO_2 emissions from the market. A detailed discussion of which new units would be allocated allowances can be found in the preamble discussion of 40 CFR Part 73.

Although new units are generally not subject to Acid Rain program emissions reduction requirements until Phase II, a new unit may become an affected unit during Phase I if it shares a common stack with a Phase I affected unit and does not monitor emissions independently (or has not been approved for alternative monitoring pursuant to 40 CFR Part 75), or if it is designated as a compensating unit in a reduced utilization plan. Today's proposal specifies that each such new unit would not be allocated allowances during Phase I and would be deemed to have a baseline of zero. Although under Section 405(g) the Administrator is authorized to allocate allowances to some new units, beginning on January 1, 2000, the statute does not provide for these units to receive allowances in Phase I. The Agency requests comment on this treatment of new units that become affected units in Phase I.

(a) *Proposal.* Section 72.45(a) specifies the units to which this provision would apply. These include two categories of units: (1) those which commenced commercial operation on or after November 15, 1990, and (2) those which served a generator with a nameplate capacity of 25MWe or less before November 15,1990 but which on or after November 15, 1990, serve a generator with a nameplate capacity of greater than 25MWe.

Although the statutory definition of existing units does not include simple combustion turbines and units which serve a generator with a nameplate capacity of 25MWe or less, Title IV defines "new units" to include these types of units.

Today's proposal specifies, in accordance with the Act, that any new unit, including a simple combustion turbine or a unit that serves a generator of 25MWe or less is subject to the requirements of the Acid Rain program. The Agency requests comment on the effect of this requirement on very small units, and whether a de minimis exclusion should be included in the final rule. For example, such an exclusion might be appropriate for emergency generators used by hospitals that do not otherwise provide peak load generation for a system.

(b) *Special Deadlines.* The designated representative of a new unit would be required to submit a permit application to the permitting authority not later than 24 months before the later of

January 1, 2000, or the date on which the unit "commences operation." Two proposed exceptions to this deadline are if a new unit serves as a compensating unit in a reduced utilization plan during Phase I or the new unit becomes affected during Phase I because of the provisions dealing with units using a common stack. Such a unit would be required to submit its permit application at the time the reduced utilization plan or common stack plan is due, i.e., the later of February, 1993 or 24 months before commencing operation.

(c) *Compliance upon Commencement of Operation.* The Agency proposes that in the permit application for a new unit, the designated representative include a "commence operation" schedule. This information is necessary to confirm the date on which the unit becomes an affected unit. It is especially important for units which commence operation after Phase II begins because the permitting authority, the Agency, and the source need to know the exact date upon which compliance begins.

The Agency proposes, in accordance with Section 408(e) of the Act, that the designated representative of a new unit hold allowances to cover the annual SO_2 emissions at that unit beginning in the year that the unit commences operation.

(d) *New Unit Emissions Monitoring Requirements.* The emissions monitoring at 40 CFR Part 75 proposes that new units must account for their emissions upon commencement of operation. 40 CFR Part 75 also specifies a default methodology for calculating emissions for any period before the monitors are fully operational.

(e) *Other Options Considered.* The Agency considered allowing new units to begin compliance with the Act upon "commencement of commercial operation", but rejected this approach because emissions during the period between "commencement of operation" and "commencement of commercial operation" could be significant. Under NSPS requirements this period could last for as long as 180 days. Congress intended that any emissions above the 8.95 million ton cap for sulfur dioxide for Phase II should be avoided. The Agency, thus, believes start-up emissions emitted by new units should be accounted for.

7. Nitrogen Oxides Options - Generally. Section 407 of the Act requires that the Administrator promulgate nitrogen oxides emissions limitations for boilers[15] that are affected units under the sulfur dioxide requirements of Title IV of the Act.

As is indicated in Part I of this preamble, the Acid Rain program emissions limitations for NO_x will be promulgated at 40

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[15] Section 402 of the Act defines the term "unit" to mean any "fossil fuel-fired combustion device." This can be a boiler, a turbine, or any other fossil fuel-fired device. The nitrogen oxides requirements of Section 407, however, apply only to units that are boilers.

CFR Part 76 at a later date. The Acid Rain compliance options for NO_x discussed in Subpart D of today's proposal are, therefore, only a partial proposal of the NO_x requirements under the program. Because NO_x requirements will be included in Acid Rain permit applications and permits, today's proposal includes a framework for the NO_x compliance options which will be addressed more substantively in the 40 CFR Part 76 rulemaking. If appropriate, following consideration of public comment on this proposal, EPA may determine to publish all the NO_x compliance options rules in the 40 CFR Part 76 regulations.

The three NO_x compliance options proposed in this section have significantly different environmental effects. Nitrogen oxides emissions averaging plans are the most environmentally neutral of the three options because they must ensure the emissions reductions that would be achieved by strict compliance with the applicable NO_x limitation for each unit. Nitrogen oxides compliance deadline extension plans allow for emissions in excess of the emissions that would be achieved by strict compliance for a limited period. Nitrogen oxides alternative emissions limitation plans allow for a permanent limitation in excess of that which would otherwise be required pursuant to 40 CFR Part 76. The latter plan is, therefore, the option most likely to impact the environment. The Agency has proposed the requirements for these three options with the intent of providing maximum flexibility, while being cognizant of their potential environmental effect. Because the NO_x emissions averaging and NO_x alternative emissions limitations options are available in Phase I and Phase II, the Agency seeks to provide for consistent implementation of these requirements nationwide. The NO_x alternative emissions limitations provisions are especially prone to inconsistent application because of the individual nature of each request and the judgments that will have to be made by the reviewer of the application rather than on standardized formulas and criteria. The approach proposed today seeks to minimize the potential for inconsistent treatment of sources State-to-State and to help ensure expeditious permitting by setting forth a framework for the specific requirements for approval of the three NO_x compliance options.

8. Phase I or Phase II Nitrogen Oxides Emissions Averaging Plans. Pursuant to Section 407(e), a NO_x emissions averaging plan would allow two or more units subject to the applicable emission limitations established pursuant to Section 407 at 40 CFR Part 76, to petition the permitting authority for alternative contemporaneous annual emission limitations for such units. Section 72.46 would specify the procedures by which a proposed NO_x emissions averaging plan would have to be submitted for approval, and some of the information requirements of the application. The Act states only in very general terms how the averaging relationship could be established and the parameters for an acceptable averaging plan. Since the emission limitations for NO_x and the rules for determining excess emissions of NO_x will

be determined in the 40 CFR Part 76 rules, the substantive requirements for an approvable averaging plan will also have to be specified in the 40 CFR Part 76 rules.

(a) *Applicable Units.* The applicability section of today's proposal states that any unit that is an affected unit for NO_x during Phase I would be able to apply for NO_x emissions averaging during Phase I. The rule provides that only those units subject to a NO_x emission limitation under Title IV could be included in an averaging plan. EPA requests comment whether only those units which are affected should be allowed to participate in NO_x averaging during Phase I. During Phase II, any unit that is an affected unit for NO_x under Title IV of the Act may apply for this option.

(b) *Common Ownership Requirement.* Units governed by a proposed nitrogen oxides emissions averaging plan would be required to have a common owner or operator in accordance with Section 407(e) of the Act. If the units are located at more than one source they may be linked by a single compliance plan signed by multiple designated representatives. The Agency also considered whether to require that in addition to a common owner or operator, all units in a NO_x emissions averaging plan also must have a common designated representative. The Agency solicits comment on these interpretations of the common ownership requirement and, in addition, on whether the requirement could be met by requiring a common designated representative.

Section 72.46 also specifies the requirements and prohibitions that would apply to averaging plans, including the requirement that the designated representative and the owners and operators of the averaged units would share responsibility for ensuring compliance by all units' with the plan, and liability for a violation at any or all units in the plan. The basis for this provision is discussed in the general section on compliance plans and in the section on designated representatives.

(c) *Special Annual Compliance Certification.* Today's proposal provides that the designated representative of any source with an approved NO_x emissions averaging plan may be required to include certain information in the end of year compliance certification in addition to the standard information required in Section 72.400. This compliance information would identify all units in the NO_x emissions averaging plan and the combined emissions limitation for these units. It would also specify the total annual emissions of NO_x for each individual unit.

9. Phase I or Phase II Nitrogen Oxides Alternative Emission Limitations Plans. Section 72.47 of today's proposal would implement the NO_x alternative emission limitation compliance option authorized by Section 407(d) of the Act. Under this section the designated representative for a unit subject to the NO_x emission limitation requirements of Title IV of the Act and 40 CFR Part 76, could request an alternative, less stringent, limitation, if a demonstration is made that appropriate control

equipment, as specified in 40 CFR Part 76, cannot meet the applicable limitation at that unit.

Today's proposal would specify the procedures by which a NO_x alternative emission limitation application would have to be submitted for approval, and some of the information requirements of the application. The substantive criteria upon which the granting of such a request would be based and the remaining procedural requirements are proposed to be specified in the 40 CFR Part 76 rules.

(a) *Applicable Units.* Section 72.47 of today's proposal specifies, in accordance with the Act, that this compliance option may be petitioned for during Phase I or Phase II by affected units subject to NO_x requirements during Phase I or Phase II, respectively according to the procedures specifies in 40 CFR Part 76.

(b) *Technology Requirements.* Today's proposal would, in accordance with the statutory authority, require that the determination to grant an alternative emission limitation must be based upon a showing, satisfactory to the permitting authority and the Administrator and in accordance with criteria to be specified by 40 CFR Part 76, that the owner or operator: (1) properly installed control equipment designed to meet the applicable 40 CFR Part 76 NO_x emission limitation; (2) properly operated such equipment for a period of no less than fifteen months; and (3) provided operating and continuous emission monitoring data as specified in 40 CFR Part 76 for such period demonstrating that the unit cannot meet the applicable NO_x emission limitation. In addition, the designated representative must specify in the application an alternative emission limitation that such unit could meet on an annual average basis.

Because such units would be unable to comply with the statutory requirement for a 15-month demonstration period, without first obtaining an operating permit, today's proposal specifies interim procedures by which a source may obtain a permit to demonstrate that a unit at that source cannot meet the NO_x emission limitation. Today's proposal presents a two-tiered application process: (1) an application for an alternative emission limitation demonstration period, and (2) an application for a final alternative emission limitation.

If a unit has properly installed and operated appropriate NO_x control equipment according to the conditions specified in 40 CFR Part 76 for at least 6 months, and the monitoring data collected in accordance with 40 CFR Part 75 demonstrates that the unit cannot meet the applicable NO_x emission limitation, then that unit would submit in its permit application, an application for an alternative emission limitation demonstration period. Based on this application, the permitting authority and the Administrator would designate (1) a demonstration period of not less than 15 months (which may incorporate retroactively some or all of the operating period prior to the date the application was

submitted), and (2) an interim alternative emission limitation for the unit for the proposed demonstration period.

If by the permit application deadline the unit has not operated for a minimum of 6 months according to the procedures specified in 40 CFR Part 76, the designated representative for the unit would not be authorized to submit a petition for an alternative emission limitation demonstration period in the permit application for that unit. Any such petition would have to be submitted as (1) an amendment to the permit application, if the Administrator had not yet acted upon the permit application, or (2) a modification or fast-track permit modification under Subpart J, if the permit had been issued.

An alternative emission limitation may also apply to any unit for which the designated representative can demonstrate to the permitting authority and the Administrator, pursuant to 40 CFR Part 76, that appropriate control equipment cannot be designed so as to meet the applicable limitation for that unit. In any such case, the designated representative would submit a petition, as specified in 40 CFR Part 76, for an alternative emission limitation in the permit application for that unit. This alternative has been included in today's proposal to provide flexibility to utilities that know in advance of installation that appropriate control equipment cannot meet the applicable limit at a unit. Such utilities would be exempt from the requirement to install and operate the equipment before submitting an alternative emission limitation demonstration period application, if a demonstration can be made based on proven engineering design that such equipment could not meet the limit at the unit. The alternative would be to put such units in a double bind because the Act requires that in order to be granted an alternative emissions limitation the unit must demonstrate it has properly installed appropriate control equipment designed to meet the applicable limitation.

(c) *Submission of Applications.* The intent of the Agency in its interpretation of the NO_x alternative emission limitations provisions of the Act was to provide sources with adequate flexibility to enable them to take advantage of this provision where absolutely necessary, while not allowing frivolous applications which might undermine the goals for NO_x emissions reductions set forth in the Act. Of the four compliance options available to sources for complying with the NO_x emission limitations, the NO_x alternative emission limitations provisions would result in the most adverse environmental impact. For this reason, the Agency has included some features in today's proposal to ensure that the alternative limitation request is absolutely necessary and is a last resort, e.g., the requirement that a unit operate for a minimum of 6 months before requesting an alternative emission limitation. The Agency believes that this proposed requirement may have the practical effect of causing many sources to apply for a permit revision in order to be granted a demonstration period. Under these conditions, a source

would probably not submit a frivolous application. This requirement would also ensure national consistency in the amount of data upon which a determination for the need for a demonstration period is based.

Approval of alternative emission limitations involves an evaluation of the equipment installed at a unit and of the operation of such equipment. This evaluation is comparatively more complex than the evaluations required for the approval of other compliance options. For this reason, the Agency is considering establishing a procedure for approval of alternative emission limitations during Phase II that involves the Administrator. Such a procedure would assist the States in their evaluation of requests for alternative emission limitations and assure consistent application of the requirements nationwide. The Agency requests comment on the inclusion of such a procedure in today's proposal.

Section 72.47(d) of today's proposal specifies the permitting authority's action on requests for NO_x alternative emission limitations. The Agency's specifications in this section mirror closely the statutory requirements of Section 407(d) of the Act. The permitting authority's action on proposals for a demonstration period have been discussed above. Today's proposal would require the designated representative of a unit which has been granted a demonstration period to submit operating and monitoring data in accordance with 40 CFR Part 76 which support the request for the final alternative emission limitation six months before the end of that demonstration period. The permitting authority would, then, take action on the final alternative emission limitation. Today's proposal would require that the permit revision be a permit modification. This proposal is consistent with the Agency's treatment of permit revisions, a discussion of which can be found in Subpart J of today's preamble.

As stated in the opening remarks of this section of today's preamble, most of the substantive requirements for NO_x alternative emissions limitation applications and determinations will be addressed in 40 CFR Part 76.

10. Phase I Nitrogen Oxides Compliance Deadline Extension Plans. Section 72.48 would implement the provisions under Section 407(d) of the Act which allow for an extension of 15 months of the Phase I NO_x compliance deadline. The intent of this provision is to alleviate a potential timing problem that may be faced by some sources during Phase I of the program. Specifically, Congress was concerned about the ability of sources affected in Phase I to comply on time due to the cumulative impacts of the following: (1) the limited number of vendors of low-NO_x burner technology, (2) the statutory schedule for promulgation of the NO_x emission limitations for affected units, and (3) the compliance deadline of January 1, 1995.

The NO_x compliance deadline extension would apply only during Phase I and only to the NO_x emission reduction provisions.

Any unit which is an affected unit for NO_x during Phase I would be eligible to apply for the extension.

(a) *Approach.* Today's proposal specifies, in accordance with the Act, that in order to be granted an extension the designated representative of the unit would be required to demonstrate to the satisfaction of the Administrator that the technology necessary to meet the applicable NO_x requirements is not in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995.

The substantive requirements for making such a demonstration will be specified in the 40 CFR Part 76 rules. The procedures proposed today would require that the designated representative of a unit applying for the extension submit a list of the commercial vendors that have been contacted by the source, with certifications from these vendors that they cannot supply the appropriate control equipment for installation by January 1, 1995, including the date on which the owners, operators, or designated representative first solicited the equipment from each vendor.

To implement the statutory limitation on extensions where a utility is claiming an inability to comply with the January 1, 1995 deadline due to system reliability, utilities would be required to show that obligations to supply electricity could not be met due solely to the need to schedule shutdowns to install the NO_x control equipment. Today's proposal also specifies that the designated representative of any unit applying for an extension would be required to submit a vendor-certified schedule for equipment installation and related construction that delineates the dates of specific milestones, including the date on which the equipment will be operational. The Agency has included the above requirements to ensure that the source made a good faith effort to install NO_x control equipment in a timely manner.

Section 72.48 of today's proposal also describes the Administrator's action on proposed NO_x compliance extension plans. If the plan is submitted as part of the original permit application, the Administrator would take initial action on it within 3 months of receipt and final action within 6 months of receipt, as required by Section 408. If the plan is submitted separately from the original permit application, the Administrator would be required to act on a proposed extension plan within three months of receipt as required by Section 407(d).

11. **Phase I or Phase II Opt-in Plans.** Section 72.49 of today's proposal would require that permit application deadlines for opt-in units be those specified in 40 CFR Part 74. EPA is reserving 40 CFR Part 74 for purposes of implementing Section 410 of the Act which allows sources that would not be affected in Phase I or Phase II to participate in the Acid Rain SO_2 program. Acid Rain requirements for sources that choose to opt-in to the

program will be promulgated at 40 CFR Part 74 in a later rulemaking.

12. Phase I or Phase II Common-Stack Plans. Section 72.50 specifies the proposed requirements for common-stack plans. When the emissions from units are ducted through and monitored in a common stack it is exceedingly difficult to reliably assign emissions to the individual units absent additional monitoring devices. In view of this concern, the Agency proposes in 40 CFR Part 75 to treat affected units that share a common stack as one unit for purposes of calculating emissions, unless the source has installed, operated, and maintained continuous emission monitoring systems that satisfy the requirements in Appendix A of 40 CFR Part 75 in the ducts to the common stack for monitoring the emissions form each unit. When affected and non-affected units utilize a common stack, the owner or operator may also employ the procedures specified in Section 75.11(a)(7) for determining the emissions from each of the affected units. In addition, the Agency has proposed to require one excess emissions offset plan under 40 CFR Part 77, from affected units utilizing a common stack. Section 72.50, thus, proposes that units utilizing and monitoring in a common stack be governed by a common-stack plan submitted in accordance with 40 CFR Parts 72 and 75. In addition, Section 72.50 would require that, in the absence of a demonstration in the permit application that separate emission monitoring systems or procedures have been duly certified in accordance with 40 CFR Part 75 for each unit, if any one unit using the common stack is not otherwise an affected unit it would have to be designated as an affected unit under the substitution, opt-in, or new unit provisions of Subpart D, as appropriate. This would be a mandatory and necessary obligation in order to hold the source accountable for all emissions from the stack.

Thus, if the combined emissions exceed the aggregate of SO_2 allowances held for the units utilizing the common stack or the NO_x emission rate that would have been allowed under the applicable emissions limitation(s), all of the units using the common stack would be treated as being in noncompliance. Moreover, since it is exceedingly difficult to assign or apportion emissions to the individual units using one monitor at a common stack, the owners and operators of all the units with emissions ducted to the stack would share responsibility for ensuring compliance with any excess emissions penalties and offset requirements.

D. *Acid Rain Permit Contents.*

Subpart E describes the content requirements of all Acid Rain permits, including general information, designated representative certifications, prohibitions, the incorporation of Acid Rain program definitions, allowance information, compliance plans, monitoring requirements, and reporting and recordkeeping requirements. These requirements are mandated by the statute or are necessary to ensure that the permit provisions are enforceable and will achieve the emissions reductions required by

the Act. Each permit would specify the annual basic and bonus allowance allocation for each unit because if the allowance system were to fail, the annual emissions limit for each unit would be that unit's annual allowance allocation.

The Acid Rain permit content requirements would apply to all Phase I and Phase II Acid Rain permits, whether those permits were issued by EPA or by a State or local permitting authority with a program approved under Title V. The purpose of the Acid Rain permit is to provide a document where all of the Acid Rain requirements that apply to an individual source, and to each unit at the source, are articulated. This would provide certainty to the source, the permitting authority, and the public regarding exactly what requirements the source is subject to under the program.

1. Permit Shield. This subpart would also address the "permit application shield" and "permit shield" effects of permit submissions under the Acid Rain program. Section 72.53(a) would, consistent with Section 503(d) of the Act, shield any source which has submitted a timely and complete permit application, from any possible liability under Section 502(a) of the Act for operating without a permit, where the source's failure to have a permit is the result of inaction on the part of the permitting authority and no fault of the source. The application shield would also apply where an affected source operates in compliance with an approved permit application and compliance plan binding on the source prior to the permit's effective date.

In addition, consistent with Section 504(f) of the Act and Section 70.6(h)(1) of the proposed Title V regulations, Section 72.52(b) of today's proposal would shield any source operated in accordance with a permit properly issued under Title IV and 40 CFR Part 72, from enforcement. The provision would give certainty to affected sources operated in compliance with the terms of a properly issued permit that they would no longer be subject to other requirements of the program that might otherwise apply. For example, a unit governed by a properly approved repowering extension, would no longer be subject to the January 1, 2000 Phase II compliance deadline.

Section 72.52(b) would, however, limit the shield that is being proposed by the Agency under Section 504(f) at Section 70.6(h)(1). Specifically, as required by Section 408(h)(2) and as authorized by Section 504(f), EPA proposes that a source would not be shielded by a provision of a permit that does not clearly comply with the requirements of Title IV or the Acid Rain program, including any provision in a Title V permit or State decision interpreting a Title V permit in a manner that would alter the applicability of a Title IV requirement to a source. The Agency interprets the language in Section 504(f) authorizing such limitations on the shield and the limiting language in Section 408(h)(2) as a protection against permit conditions, including conditions resulting from a State interpretation of a permit provision, that would alter essential Acid Rain program requirements such as the requirements governing designated

representatives, emissions monitoring, recordkeeping, and reporting, approval of compliance options, and liability. The Agency requests comments on the permit shield provisions in today's proposal.

E. *Acid Rain Phase I Implementation.*

1. Description of Process. Subpart F describes the proposed implementation of the Phase I Acid Rain permit program. The units covered under Phase I of the program, listed in Appendix A, generally include the largest plants with the highest SO_2 emissions in the United States. In addition, certain other units may become affected units in Phase I of the program under one or more of the compliance options provided in Subpart D. Title IV of the Act mandates that SO_2 and NO_x emissions reductions for Phase I affected units begin on January 1, 1995 and continue in effect until December 31, 1999. While the Phase I emissions reduction obligations begin on January 1, 1995, some Phase I requirements begin earlier.

Title IV requires that Phase I permitting be implemented by EPA. The Agency will process permit applications, write and issue permits, and process permit revisions. In addition, in cooperation with State and local air quality agencies, EPA will monitor compliance and take appropriate enforcement action as necessary. In contrast, permitting for Phase II of the Acid Rain program, which begins January 1, 2000, will be implemented by States with approved operating permit programs under Title V of the Act, and by EPA only for sources in States where an operating permit program has not been approved. This subpart includes the proposed deadlines and procedures for the Phase I permit program only.

Consistent with Section 408, the basic permitting process for Phase I would be as follows: The designated representatives for Phase I affected sources would be required to submit Acid Rain permit applications and proposed compliance plans to the Agency on or before February 15, 1993. (Designated representative certifications under Subpart B, would have to be filed for each Phase I affected source not later than with the permit application.) The Agency would review and act on these applications, using the procedures set forth in Subpart G including an opportunity for public comment, within 6 months of receipt. (For sources applying on February 15, this would be about August 15, 1993; earlier applications would receive earlier attention.) The rule would afford sources and persons who commented on proposed permits an opportunity to appeal permitting decisions (using the procedures set forth in Subpart H). The appeals would have to be filed within 60 days of the Agency's decision; thus, ensuring that disputes will be resolved prior to the emissions reduction requirements that begin on January 1, 1995.

2. Treatment of Effective Date of Permits. Section 408(a) of the Act specifies that Acid Rain permits have a term of five

years, but Section 408(c)(2) requires EPA to act on compliance plans by August 15, 1993. EPA believes that the clear intent of Congress was for Phase I Acid Rain permits to remain in effect for the 5-year duration of Phase I. Thus, the Agency is proposing to issue Phase I permits on or about August 15, 1993, and to have those permits take effect on January 1, 1995. This interpretation of the statutory deadlines would ensure that the Phase I permits will not expire in the middle of Phase I.

The rule would also clarify what requirements apply to the source prior to the permit's effective date. Specifically, the permit application and compliance plan would be binding on the source upon a determination of completeness until the permit became effective. EPA could, thus, ensure compliance by the source with monitoring and other Acid Rain requirements that must be met before January 1, 1995. EPA's authority to approve, disapprove, or modify permit applications and compliance plans would afford further protections.

The Agency believes that the proposed approach to the permit term and effectiveness issue best reflects the intent of Congress. It allows permittees and interested parties the flexibility to contest Acid Rain permit conditions before commencement of Phase I emissions reduction requirements, reduces the potential burden of redundant permitting, yet ensures that essential program elements will continue to be in place.

F. *Federal Acid Rain Permit Issuance Procedures.*

1. Approach. This subpart describes the proposed issuance procedures for Federal Acid Rain permits. The authority for the permitting procedures set forth in this subpart can be found in Section 408(a) of the Act, which mandates that the provisions of the Title IV be implemented by permits issued to affected units in accordance with the provisions of Title V (40 CFR Parts 70 proposed at 56 FR 21712, May 10, 1991, and 71), as modified by Title IV. These procedures are intended to be as consistent with 40 CFR Parts 70 and 71 as possible, while addressing the particular permitting concerns of the Acid Rain program. The Agency requests comments on coordination of this subpart with the operating permits program. EPA also requests comments on the coordination between requirements in this subpart which apply to State Acid Rain permitting programs (40 CFR Part 72, Subpart I) and the State operating permits program set forth at 40 CFR Part 70.

Title V of the Act is largely based on the Agency's existing Clean Water Act permitting program, the National Pollutant Discharge Elimination System (NPDES). Congress believed the NPDES program was relatively successful in reducing pollutants in the waters of the United States, and used the NPDES program as a model for Clean Air permitting. In keeping with Congress' intent to base Clean Air permitting programs on existing Agency permitting programs, this subpart is modeled in large part on the consolidated permitting procedures set forth at 40 CFR Part 124. The Part 124 procedures are used for the NPDES program, the Resource Conservation and Recovery Act (RCRA) permitting program,

and the Prevention of Significant Deterioration (PSD) air permitting program. The Agency believes that it is preferable to build on these existing procedures, rather than developing completely new permitting procedures. While 40 CFR Part 124 is used as the basis for today's proposed procedures, the Agency has made modifications to those procedures to ensure consistency with Title V, to address the particular concerns of Acid Rain permitting, and to modify aspects of the 40 CFR Part 124 procedures which have not worked effectively in these other permitting programs. Thus, while the procedures set forth in today's proposal are similar to those in 40 CFR Part 124, they are not identical. The Agency requests both overall comments on the procedures in today's proposal and comments on specific aspects of the proposed procedures.

The permit issuance process proposed in this subpart is as follows: the permit writer would determine whether the application and compliance plan submitted by the designated representative is complete. After all additional information has been obtained, the permit writer would prepare a proposed permit and an accompanying statement of basis, which would describe the legal and factual basis of the permit requirements. Public notice would be provided on the proposed permit, and the public would have an opportunity to comment and ask for a public hearing.[16] Following submission of all comments, the permit writer would revise the proposed permit based on the comments. The revised permit would be issued as the permitting decision, after which appeals to the permit may occur.

2. Regional Role. The proposal would require that copies of all Acid Rain program filings be sent simultaneously to the State, to the EPA Regional Air Program Division, and to the EPA Headquarters, Acid Rain Division. The date of receipt of permit submissions would be determined by the date of receipt at the appropriate U.S. EPA Regional office. This proposal does not, however, articulate whether the Regions or Headquarters will issue the Phase I permits, and Phase II permits where the State defaults, or whether the Regions will have a role in Acid Rain permit appeals. Instead, the proposal uses the term "Administrator". EPA's current thinking is that the Agency would employ a team approach in taking any Federal permit action during which the EPA Regional office, EPA Headquarters office, and the State would work together. The Regional office would, however, maintain the official record of permit actions and would officially issue the permit.

Traditionally, implementation of Federal environmental permitting programs has been delegated to the Regions. Such an

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[16] In its public notice, the Agency will provide a phone number or method of access to an electronic bulletin board to ensure the public can obtain information on whether a hearing will be held on the proposed permit, and the time and location of any scheduled hearing.

approach is logical since the Regions are more familiar with the sources. The Regions also would be responsible for reviewing State permit programs beginning in 1993 for consistency with the Acid Rain program, and for reviewing proposed State-issued operating permits in Phase II. Similarly, administrative challenges to EPA actions are traditionally heard in the Regional Offices, with the Administrative Law Judge's office operating a circuit managed by the Regional Hearing Clerks. This is particularly appropriate since the record of a permit action and information about the source is located in the Regional Office. Thus, the Regions will undoubtedly play a critical role in the Acid Rain program. Certain permit actions might, however, require a Headquarters lead to improve national consistency in Acid Rain permitting requirements.

G. *Appeal Procedures for Acid Rain Permits.*

Subpart H describes the proposed rights and procedures for administrative appeals of permitting decisions of the Administrator under the Acid Rain program.[17] Subpart H also lists other Acid Rain program decisions of the Administrator that are not "permitting decisions" and, therefore, not subject to the procedures of Subpart H even though they may ultimately be incorporated into the Acid Rain program permit provisions applicable to the source. These include any action by the Administrator relying on a certificate of representation submitted under Subpart B; any action by the Administrator regarding a proposed excess emissions offset plan under 40 CFR Part 77; or any action by the Administrator on a proposed alternative emissions monitoring system under 40 CFR Part 75. The Agency is, however, considering whether all decisions by the Administrator under the Acid Rain program pursuant to 40 CFR Parts 72-78 should be subject to an appeals procedure such as is proposed today.

Section 307 of the Act provides an opportunity for judicial review of final Agency action under the Act in Federal circuit court. Such judicial review is available after the petitioner has exhausted all administrative remedies, such as administrative appeals procedures. Use of an administrative appeals procedure is consistent with other environmental permitting programs, including the NPDES, RCRA, and PSD programs. An administrative appeals procedure is, moreover, appropriate since it would allow the Agency to review permitting decisions for correctness before having to defend permitting actions in Federal court. This approach would also provide petitioners with a less resource intensive (and less time-consuming) process for resolving

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[17] The term "permitting decision" is defined in section 72.2 as any permitting action taken by the Administrator under the Acid Rain Program following the administrative procedures of 40 CFR Part 72, including where provided for, an opportunity for public comment. (See, also definitions for "proposed permit")

disputes concerning Acid Rain permit conditions, than would be involved in a judicial action.

The administrative appeals procedures proposed in Subpart H are guided by two concerns: (a) the need to expedite the appeals process (particularly since an opportunity for public comment would have already been provided before any permitting decision was reached), and (b) the need to provide a forum for resolving factual disputes if necessary in any final review by the Administrator.

The rule would allow appeals of decisions by the Administrator on the basis of factual, legal, or policy issues. The rule would include limited opportunity for an evidentiary hearing to resolve disputes concerning genuine issues of material fact. Specifically in reviewing any appeal involving disputed issues of fact, the Administrator would have the option of referring the case to a Presiding Officer (See definitions) appointed by the Chief Administrative Law Judge to conduct an evidentiary hearing. If permit issuance responsibility is delegated to the Regions (See discussion of Subparts F and G), the Agency proposes that such appeals would be heard in the Region in which the affected unit is located.

The rules and procedures proposed today for conducting evidentiary hearings are based on the procedures used for permit appeals in the NPDES program, and on the Federal Rules of Civil Procedure. To ensure expedition, Presiding Officers would be required to: limit evidentiary hearings to genuine issues of material fact, limit evidence to such factual issues, and bar testimony on legal and policy issues. The Presiding Officer would, moreover, be authorized to limit the hearing to a paper evidentiary hearing where direct- and cross-examination of witnesses would not be necessary for a full and true disclosure of the facts. This is appropriate since permitting is an essential rulemaking function and, as previously mentioned, there would already have been an opportunity for public comment.

The rule proposes that the standard of review to be applied by the Administrator and Presiding Officer be as follows. The person seeking a permit would bear the burden of proof that the permit should be issued. Any person challenging the permitting decision would bear the burden of going forward and showing that: (1) with regard to any factual finding or legal conclusion underlying the permitting decision, the standard is "clearly erroneous"; and (2) with regard to an exercise of discretion or a policy determination underlying the permitting decision, the standard would be "arbitrary and capricious". These standards are consistent with the traditional standards for reviewing actions of agencies under the Administrative Procedures Act.

After a petition for review is filed, the Administrator would grant or deny the petition and have the option to refer the petition to a Presiding Officer for evidentiary hearing. If the petition for review is granted and an evidentiary hearing is not granted, the parties may file briefs. The Administrator would, thereafter, issue a final order addressing the appealed issues.

The order, supplemented by the record of the appeal and of the decision, would become the final Agency action.

If the case is referred to a Presiding Officer for hearing, the Presiding Officer's review would conclude with a proposed order. The proposed order would become a final Agency action, unless (a) the Administrator issued a notice of intent to review within 30 days, sua sponte; or (b) a party filed a further appeal to the Administrator objecting to the proposed order within 15 days and the Administrator issued a notice of intent to review the proposed order pursuant to the objection. An appeal of a proposed order to the Administrator would have to allege that a finding of fact or conclusion of law was clearly erroneous, or that an exercise of discretion or a policy determination was arbitrary and capricious. In issuing a notice of review, the Administrator would have discretion to allow briefs by the parties.

The Agency has proposed this approach because it would allow for full development of factual disputes during the administrative review process. It would afford the Agency an opportunity to correct erroneous factual determinations, and ensure that the permit writer appropriately applied the regulatory and statutory requirements to the site-specific circumstances of the source. This approach would also allow the Agency to fully consider the legal and policy implications of a permitting decision, prior to any judicial review.

1. Other Approaches Considered. The Agency also considered proposing permit appeals procedures that would not afford any opportunity for a hearing. Such an approach is used in the RCRA and PSD programs which do not provide for evidentiary hearings, where challenges to permitting decisions are filed with the Administrator. The Agency considered whether such an approach might be appropriate here since: the permit decision would have been reached following a full opportunity for public comment, and evidentiary hearings can be resource intensive. The Agency believes, however, that allowing a procedure for a full airing of factual issues would ultimately reduce delays in the permitting program. This is particularly the case since factual hearings could help expedite reviews by the Administrator, and since the absence of a hearing procedure could increase the risk of judicial remands to the Agency for further development in cases alleging genuine issues of material fact. In addition, using an evidentiary hearing process the Administrator would have a more complete record to review concerning any factual issues than if he or she were to make a decision based solely on the permit issuance record. Thus, an administrative proceeding which only allowed for an appeal to the Administrator would not necessarily be more expeditious. The proposed procedure would, thus, tend to remove any doubt that decisions accurately reflect the policies of the Agency.

Perhaps the strongest criticism of an evidentiary hearing process is the time involved in an appeal. Today's proposal, therefore, would not only limit hearings to cases where they are

really necessary, but would also establish deadlines for parties' submissions and for certain Agency actions. The proposed limitations and deadlines would speed evidentiary hearings and, thus, reduce the burden of hearings on the Agency, on permittees, and on parties seeking to appeal permit conditions. The Agency requests comment on whether to provide for an evidentiary hearing process or an abbreviated process similar to that used in the RCRA and PSD programs for appealing initial decisions of the Administrator.

H. *Acid Rain Phase II Implementation.*

Subpart I sets forth the permitting requirements for Phase II of the Acid Rain program.[18] Unlike Phase I, Section 408 requires that Phase II permitting be implemented by States with operating permit programs approved under 40 CFR Part 70 by July 1, 1996. In the event a State's permit program has not been approved in time under 40 CFR Part 70, EPA would implement the Acid Rain permit requirements for affected sources in that State in accordance with 40 CFR Part 71 and this part. (The process for Federal permitting of Phase II requirements would be the same as for Phase I and for other Federal permit issuance under 40 CFR Part 71 in instances of State defaults under 40 CFR Part 70.) In some cases, a State may obtain 40 CFR Part 70 program approval after July 1, 1996, but before the EPA has issued initial Phase II permits to all of the Acid Rain sources in the State. Some States may have relatively few Phase II Acid Rain sources to begin with. The EPA, thus, proposes to reserve the right to delegate responsibility for permit review and implementation to such a State, potentially including permit issuance for all unpermitted Acid Rain sources, if EPA determines that such a delegation would not result in undue burden for the permitting authority or delay.

Pursuant to the schedules and procedures of Title IV, Subpart I would require affected sources to submit Phase II permit applications and proposed compliance plans for SO_2 by January 1, 1996, for NO_x by January 1, 1998, and for new units twenty four months before the latter of January 1, 2000 or the date the unit "commences operation". Copies of each application would have to be sent to the State, to EPA Headquarters, and to the Region.

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[18] Phase II emissions reductions begin on January 1, 2000 following the conclusion of Phase I. Some other Phase II requirements begin earlier (e.g. emissions monitoring, and schedules for sources applying for repowering extensions). In Phase II, the remaining affected units that were not regulated in Phase I, e.g., those listed in Appendix B of today's proposal, will be subject to Acid Rain Program emissions reduction requirements. New units and units that "opt in" under the terms of 40 CFR Part 74 will be regulated as well.

Subpart I provides that the State with an approved program would make a determination of completeness in accordance with 40 CFR 70.5(c), and would notify the Administrator of such determination.[19] The permitting authority then would write a "draft permit" (See, Section 72.2 definitions) and allow opportunity for public comment in accordance with Section 502(b)(6) and proposed 40 CFR Part 70(i). Following the public comment period, the State would submit a "proposed permit" to EPA for review. Following EPA review, and assuming EPA did not veto the proposed permit as provided in proposed Section 70.8, the Acid Rain permit would be issued. Section 408 mandates that Phase II SO_2 permits be issued by States on or before December 31, 1997. As is discussed above regarding Subpart E, applications would be binding on sources before the permit is issued.

The schedule mandated by Title IV for issuing initial Phase II Acid Rain permits coincides roughly with the first two years for States to complete issuing original permits under Title V and proposed 40 CFR Part 70. Pursuant to Title IV, State permitting authorities are required to issue permits for Phase II SO_2 requirements by December 1997. Pursuant to Title V, within four years after a State receives EPA approval of its Title V permit program it must complete the process of issuing Title V permits covering *all* Clean Air Act requirements to all sources in its jurisdiction. Thus, under today's proposal the Acid Rain program Phase II SO_2 requirements would appear as a separate section of the operating permit issued to an affected source under Title V and 40 CFR Part 70.

With regard to the Title IV NO_x permitting deadlines, applications are not due until January 1, 1998. Thus, where a source did not file its NO_x limitation application with its Phase II SO_2 permit application in 1996, the State would have to reopen the previously issued permit "for cause" to add the pertinent NO_x provisions. Similarly, if a Title V operating permit covering SIP requirements were issued to a source under 40 CFR Part 70 before the deadline for sources to submit, or for States to act on, Acid Rain Phase II SO_2 permit applications, the State would have to reopen the Title V permit "for cause" to incorporate the Acid Rain SO_2 requirements. As is discussed further below,

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[19] The permit application and proposed compliance plan are binding on the source prior to permit issuance. (See § 408(d)(3).) The Agency is proposing that the application and proposed compliance plan be binding upon submission to the permitting authority. The Agency believes, however, that a disapproved or incomplete application should not be binding because it does not meet the applicable requirements of the Act. The rule proposes that the State inform EPA if any completeness determination in order to know whether the application is binding on the source and enforceable.

permits for affected sources are required by Section 408 to have a fixed term of five years. To prevent permit cycle problems, States would be required by 40 CFR Parts 70 and 72 to put affected sources on a 5-year cycle for *all* permitting requirements.

1. Appeals of State Issued Permits. Consistent with 40 CFR 70.4(b)(3)(x) and Section 502(b)(6) of the Act, appeals of Acid Rain provisions in State-issued permits would occur through State administrative and judicial appeals procedures. The Agency believes this requirement is appropriate since the expression of Congressional intent in Section 502(b)(6) that States undertake these functions is clear. In addition, with the exception of matters constituting actions of the Administrator (See discussion below), the State will have made the permitting decisions which will be considered on appeal. Furthermore, the Acid Rain requirements will be only one portion of the State-issued operating permit applicable to an affected source, and other operating permit provisions may also be at issue in any appeal.

Decisions of the Administrator that are incorporated into State issued Acid Rain permits would, however, be subject to the administrative appeals procedures set forth at Subpart H, and to judicial review in Federal circuit court pursuant to Section 307(b)(1) of the Act which provides an opportunity for Federal court review of "final actions of the Administrator". Decisions of the Administrator that must be incorporated into the source's operating permit include: acceptance of a designated representative certification and issuance of a designated representative identification number, approval of a monitoring plan, certification of a monitoring system and or of an alternative emissions monitoring system under 40 CFR Part 75, approval of an excess emissions offset plan under 40 CFR Part 77, and determination of whether a proposed technology meets the criteria for a repowering extension under Subpart D. The Agency believes that such decisions of the Administrator should be appealed Federally rather than through State procedures because: (1) the State was not involved in making the decision, (2) a Federal review procedure for these decisions will help ensure a nationally consistent body of judicial precedent, and (3) as final Agency action, the decisions will be reviewable in Federal rather than State court. The Agency is, therefore, proposing that decisions of the Administrator that are incorporated into the Acid Rain portion of a State permit be subject to Federal administrative, and (upon becoming final) Federal judicial appeal procedures if challenged. This is consistent with statutory authority, as any final decision of the Administrator is reviewable in Federal court under Section 307(b)(1) of the Act, and is therefore not appropriate for State court review. State court actions in such cases is preempted.

In addition, Section 72.202 of today's rule proposes Acid Rain-specific criteria for approving State operating permit program approval. These criteria, which would ensure adequate

notice and opportunity for EPA to participate in challenges to Acid Rain permit provisions during Phase II, include:

- Providing actual notice to EPA of administrative or judicial proceedings at the State level concerning an Acid Rain provision of any permit;
- Providing actual notice to EPA of any order or decision issued following a State administrative or judicial proceeding that interprets, modifies, voids, or otherwise relates to any portion of an Acid Rain permit. (Following any such decision, EPA would have an opportunity to review the permit pursuant to 40 CFR 70.8);
- Authority effectively granting EPA the right to intervene in any administrative or judicial appeal before the State involving an Acid Rain permit provision;
- Limitations to ensure that no appeal concerning an Acid Rain permit provision will result in a stay of any such provision, except as provided in Section 72.95.

These criteria are specified to help ensure nationally consistent implementation of the Acid Rain program. As has been discussed elsewhere in today's proposal, national consistency is necessary to ensure an active allowance market that is not hindered by local inconsistencies in Acid Rain implementation. The actual notice requirements will ensure that EPA has an opportunity to become involved in a State level appeal, and that decisions interpreting Acid Rain permit provisions in a manner that is inconsistent with the national implementation of the program will be treated as proposed permit modifications subject to review by the Agency. Affording the Agency the right to intervene in any State administrative or judicial appeal of an Acid Rain permit provision in order to inform the State agency or court on any issues of concern to the Acid Rain program as a whole would further help ensure a nationally consistent program. In addition, a right of intervention would afford EPA a clear opportunity to seek removal to Federal court of any proceeding that might raise a question of Federal law by interpreting Acid Rain requirements in a way that is significantly inconsistent with the national program.

The Agency also believes that it is in the interest of the States to provide these opportunities for Agency participation in challenges to Acid Rain permit provisions. A State administrative or judicial proceeding could inadvertently result in interpretations of Acid Rain requirements inconsistent with the national Acid Rain program. This interpretation could bind the State permitting authority when issuing subsequent Acid Rain permits. The Agency would have to veto each such permit and possibly revoke approval of the entire operating permits program until the problem was remedied. The Agency believes that such an outcome would be far more intrusive and detrimental to the State and EPA than the approach proposed today.

The Agency also proposes to require that State appeals procedures include the limitations on stays of Acid Rain permit provisions specified at Section 72.95. The Agency believes that these limitation provisions are essential to the proper functioning of the Acid Rain program and is, therefore, proposing today to require States to include these provisions in their regulations as a precondition to receiving approval of an operating permits program. This section disallows stays of standard permit provisions that are mandated by Title IV and the Acid Rain program regulation, or of provisions that are essential to the functioning of the Acid Rain program. This requirement is designed to ensure that appeals are not brought by sources seeking to escape from the Acid Rain requirements of the Act, and to protect sources from challenges brought by other "interested persons" for the purpose of pressuring the source to meet demands that may or may not be related to the Acid Rain program or risk non-compliance because of stays of, for example, an extension, during an appeal.

The Agency requests comments on this approach and on the extent to which States already have the legal authority to comply with the State program approval criteria specified above.

2. Permit Term. Title IV mandates that Acid Rain permits be issued for terms of 5 years. The Agency is proposing that Phase I permits (which will be issued in 1993) be effective from January 1, 1995 through December 31, 1999 to coincide with Phase I. In addition, the Agency seeks comment on three options for integrating Title IV Phase II and Title V permit issuance.

Under one option States would schedule all Title V permitting for affected sources so that the effective date of the Phase II permits would run from January 1, 2000 to 2005. Under this approach the State would "issue" the permit in 1997 as required by statute, but the permit would have a delayed effective date. The State would reopen "for cause" the already-existing EPA-issued Phase I permit to add other Clean Air Act requirements, such as SIP limitations. This combined permit would expire on December 31, 1999, five years after the date on which the Phase I permit originally became effective (January 1, 1995). In addition, the State would concurrently issue a second Title V permit to the source. This second permit would be effective from January 1, 2000 through December 31, 2004, and would include all applicable Clean Air Act requirements (e.g., SIP or NSPS requirements and Phase II Acid Rain requirements). Under this approach only one Title V permit would be effective at any given point in time. This approach would be consistent with the approach proposed for the Phase I permit cycle, but has several drawbacks. First the approach will only be available for those affected sources that were regulated, and issued permits by EPA, in Phase I. This is only a small fraction of the total

number of sources which must be issued permits for Phase II.[20] In addition, some Phase II requirements begin before the year 2000. For example, sources choosing to repower must notify EPA of their intent by December 31, 1997. In addition, all Phase II sources must have their emissions monitors certified by January, 1995. Ideally those requirements should be incorporated into the permit for the source. If the Phase II permit has a delayed effective date, the requirements would have to be added to the Phase I permit.

Thus, for many sources, delaying the permit's effective date until January 1, 2000, would not be practical and delaying the effective date of the Phase II permit until January 1, 2000, would not result in any resource savings for the source or the permitting authority. The Agency, therefore, recommends that the States endeavor to issue Phase II Acid Rain permits on the same cycle as other permitting for the source.

Under the second and recommended option the State would issue all Title V operating permits to affected sources by no later than December 31, 1997, as in option one. But, unlike option one, the State would not reopen the original EPA-issued Phase I permit. Instead, it would issue a separate Title V permit that would become effective immediately upon issuance in 1997 and would remain effective for five years, through 2002. This separate permit would not include or address in any way any of the Acid Rain Phase I requirements covered by the EPA-issued permit, but would contain all the Phase II Acid Rain requirements as well as all other Clean Air Act requirements (e.g., SIP limitations and other Title V specific permit requirements). Thus, although both the EPA-issued Phase I permit and the State-issued initial Phase II permit would be in effect during a short period of overlap (1998 and 1999), all requirements that must be met by the source will thereafter be contained in one permit document.

Under a third option States and sources would be allowed flexibility to rely on one of the two approaches just discussed, or to adopt some other approach. The only constraint would be that any approach adopted by the State would have to conform to the permitting deadlines in both Titles IV and V. Under this option the State permit program approval criteria in Section 72.202 would include a requirement that the States propose the approach they intend to use to integrate the Title IV - Title V permitting requirements when submitting their permit programs to EPA for approval.

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[20] There are 110 sources which must obtain permits for Phase I of the Acid Rain program. Some as yet unknown additional number of sources will have to obtain Phase I permits if they have substitution or compensating units (See discussion of Subpart D). Over 1000 affected sources will be subject to Phase II.

The Agency requests comment on the three integration approaches, and whether any one approach should be mandated in the final rule.

The Subpart I regulations are designed to ensure that when the States issue the Acid Rain portion of operating permits to affected sources within its jurisdiction, the goal of national regulatory consistency among all Acid Rain permittees will be met. The Agency recognizes, however, that the State will issue an Acid Rain permit as a component of a larger operating permit. To the extent possible, the regulations are structured to allow a State to issue the permits in a manner consistent with the permit issuance procedures that will be in place under an approvable Title V program. The regulations seek to achieve the goal of minimal State administrative disruption by relying, whenever possible, on the Title V regulations proposed at 40 CFR Part 70. The Agency invites public comment on whether there are unnecessary inconsistencies between the proposed Title IV and V regulations and solicits comments on specific ways of improving coordination and consistency to the extent possible.

1. State Program Approval Criteria. Subpart I includes the Acid Rain program criteria that would have to be met by any State seeking EPA approval of an operating permit program under Title V of the Act and 40 CFR Part 70. It provides, first, that the Administrator will withhold or withdraw approval of a permitting program submitted under 40 CFR Part 70 if the program authorizes any measure, or is implemented in a manner, that would interfere with the Acid Rain allowance program. Measures or implementation that would constitute such interference, and are thus prohibited, include but are not limited to:

- prohibitions on the acquisition or transfer of allowances by an affected unit located in the State or area under the jurisdiction of the permitting authority;
- restrictions on an affected unit's ability to sell or otherwise transfer allowances;
- requirements that an affected unit maintain a reserve of allowances over and above those necessary for purposes of prudence;
- failing to notify the Agency of any State-level appeals to, or decisions covering Acid Rain permit provisions, that might affect Acid Rain program requirements;
- the issuance of orders by the permitting authority inconsistent with Title IV interpreting Acid Rain program requirements as not applying to a source in whole or in part, or otherwise modifying the requirements; or
- any other measure that the Administrator determines would hinder the flexible operation of the Acid Rain allowance program.

In addition, to ensure national consistency in the Acid Rain program implementation, Section 72.202(i) provides that State permit programs would not be approvable unless they:

- provide for notification to the Agency in the event of a permit appeal under Section 502(b)(6) of the Act that might affect Acid Rain program requirements;
- impose a time bar that limits when appeals of Acid Rain permit provisions can be brought;
- authorize Agency intervention in any State-level permit challenge as a matter of right; and
- require submission to the Agency, as a proposed permit modification subject to Section 70.8 review, of any determination by the State interpreting any permit requirement in a manner that might change or void the requirements.

The Agency believes that these criteria are necessary to ensure that States do not inadvertently interfere with nationally consistent implementation of the Acid Rain program. The rule provides further that EPA will revoke a permit "for cause" in the event of any administrative or judicial State determination concerning the permit that is inconsistent with Title IV of the Act and 40 CFR Parts 72-78.

In addition, Section 72.202(b) of the proposal provides that the Administrator will withhold or withdraw approval of any permit program, if the permitting authority interferes with the Administrator's decision regarding an excess emissions offset plan. The goal of the Acid Rain program is to achieve national reductions in the total loadings of SO_2 and NO_x while allowing sources maximum flexibility in determining least-cost methods of compliance. To ensure that actual reductions occur, the statute provides for stringent excess emissions offsets and penalties. These offsets and penalties are designed so that emitting beyond the number of allowances held will never be cost-effective for a source. This enforcement authority counterbalances the incentive program provided by allowance trading, and should not be undermined by inconsistent State enforcement. Therefore, the Agency is proposing to limit the States' authority to interfere with Agency decisions regarding excess emissions offset plans.

The Agency also plans to ensure national consistency by requiring the permitting authority to use standardized forms or the Acid Rain Program Electronic Permitting System for Acid Rain permit applications and compliance plans, permits (including standard conditions), designated representative certifications, and compliance certifications. Use of these forms or the computerized permitting system will help to ensure nationally uniform implementation of the permitting requirements, and to prevent the increased costs that would be associated with the imposition by States of additional Acid Rain permitting requirements. The Agency believes that this requirement will facilitate the allowance market because all sources, no matter where they are located, will be subject to the same requirements.

The Agency requests comments on these criteria for State program approval.

I. *Permit Revisions.*

Subpart J specifies the procedures that would apply for revising Acid Rain permits. The rule proposes that permit revisions would become effective upon approval in accordance with the procedures specified in Subpart J. This is to ensure that no proposed revision could be used to insulate a source from the obligation to comply with a permitted requirement, and to provide clarity regarding what applies to a source at any given point in time.

Generally, the proposed rule tracks the permit revision requirements in proposed Section 70.7, which would apply to State permitting programs under Title V of the Act and 40 CFR Part 70. The Title V rules propose three types of permit revisions: permit modifications, minor permit amendments, and administrative permit amendments. Subpart J of today's proposal specifies how various types of changes to Acid Rain permits would fall into the 40 CFR Part 70 categories of revisions. It also proposes an additional category of automatic permit amendments, and proposes a procedure to expedite the permit modification process.

1. Prohibited Revisions. The rule ensures that certain Acid Rain permit provisions cannot be modified. For example, notwithstanding any changes a source makes in its method of compliance, each unit must hold enough allowances in its Allowance Tracking System account to cover its SO_2 emissions for the year. This requirement cannot be revised. Other standard provisions would similarly not be subject to any possible revision.

2. Modifications. Today's proposal specifies that, within the 40 CFR Part 70 structure, the Acid Rain program would apply permit modification procedures to changes such as the addition of a new compliance option that the source did not submit to the permitting authority with the initial permit application for review and comment during the permit issuance process, and that involves a unit at a source that was not previously affected and subject to the Acid Rain permit's requirements.[21] The Agency also proposes to use the permit modification procedure (or a

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[21] The concept of "modification" as used in an Acid Rain Program context is distinct from the use of the term in an NSR or NSPS context under Parts C or D or Section 111 in Title I of the Act. The Agency's proposed "WEPCO decision" [56 FR 27630, June 14, 1991], therefore, does not affect today's proposal. The revision of the modification definition for purposes of "WEPCO" concerns physical or operational changes to the facility, in particular, pollution control projects which could affect ambient air quality. Certain changes (pollution control projects) will be exempt from NSPS and NSR so long as they are "not less environmentally beneficial". A change in an Acid Rain compliance option may or may not involve a pollution control project. However, no such change would alter ambient program requirements applicable to the source.

variant allowing fast-track modifications as discussed further below) for revisions to a previously approved compliance plan that involve units not previously governed by the plan.

The Acid Rain compliance option is a fundamental component of the permit. Certain changes in the compliance option, such as those described above, have significant implications for allowance allocations, on emissions levels, and sometimes, on unit coverage under the program. Thus, the Agency believes that certain significant changes to compliance options must not occur without an opportunity for review and public input where appropriate. Where, however, a new or revised compliance option does not involve a unit not previously affected, for example a new reduced utilization plan relying on energy conservation measures where no compensating unit is designated, the permit modification procedure would not apply.

In addition, Sections 72.300(e) and 72.301 provide that a State decision interpreting an Acid Rain program permit provision in a manner that effectively modifies or voids a program requirement would be deemed a proposed permit modification by operation of law. As with any proposed permit modification by the State during Phase II, such an interpretation would be subject to Agency review pursuant to Section 70.8 of the Title V rules. Under 40 CFR Part 70 public comment and Federal oversight, as required for original permit issuance, would be required for modifications except that such comment and oversight would cover only the proposed permit changes, rather than the unchanged activities at a source.

The Agency believes that an expedited procedure is appropriate to allow for permit modifications in a manner that will provide sources with the flexibility to make needed changes in a timely manner. Without such a procedure sources would have to follow the more burdensome modification procedures discussed above and specified in 40 CFR Part 70. Today's proposal, therefore, includes a separate "fast-track" modification procedure, at Section 72.302, which could be used at the option of the source in lieu of the modification procedure of Section 72.301, for example, (1) where an affected source wishes to change its method of compliance with the Acid Rain program requirements to an Acid Rain compliance option under Subpart D which it did not submit for approval and comment during the permit issuance or reissuance process and which, in the absence of the fast-track procedure, would have to made pursuant to the modification procedure of Section 72.301; (2) for a change in a Phase I Extension, repowering extension, NO_x extension, NO_x averaging, or NO_x alternative emissions plan; or (3) for a change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program or an affected unit becoming unaffected. As is noted above, these types of changes are fundamental to the Acid Rain program and would normally be subject to the permit modification process. The time and resources involved in the permit modification

process set forth in 40 CFR Part 70 would, however, take away much of the source flexibility which the Acid Rain program was designed to ensure. Congress intended the Acid Rain program to promote least-cost planning through optional methods of compliance and an active allowance market. Requiring the affected source to go through a time- and resource-intensive process each time it wished to change its method of compliance would restrict much of the flexibility of the Acid Rain program. Sources should be able to revise their methods of compliance where the method originally chosen does not turn out to be cost-effective.

Balanced against this interest is the need to provide an opportunity for public involvement to ensure that the source is held accountable for the requirements in its permit. The Agency is, therefore, proposing a fast-track modification procedure to avoid the excessive delays associated with the permit modification procedure proposed in 40 CFR Part 70, while providing appropriate review and where appropriate public involvement. The proposal includes two options for the fast-track modification procedure. The Agency requests comment on both.

In most cases a prudent source, uncertain of the most cost-effective method of compliance, will seek conditional approval of several compliance options in its permit application and compliance plan. The Agency encourages sources to do this. In this way, when the source notifies EPA of the compliance option it wishes to use, or that it wishes to switch methods, the permit could be revised through the administrative amendment procedure discussed below. (See, also Section 70.7(e)) The Agency believes this approach is appropriate because the compliance option will have undergone public notice and comment during the permit issuance procedure.

Sources may not, however, always be able to predict all possible methods of compliance that they might need during the permit issuance process. A source may wish to change the method of compliance for a unit in the middle of the permit term.

Three approaches to fast-track modifications are offered. Under the first approach, the applicant would submit the proposed revision to EPA. EPA would then have 30 days to approve or disapprove it. If EPA proposed to approve the revision, actual notice would be sent to interested persons, i.e., all persons who (1) commented on the proposed permit, or (2) requested to be informed of any subsequent permit actions proposed to be taken concerning the source. (The second category of interested persons could get their names on a mailing list for notice of any subsequent permit actions, whether or not they had comments on the initial proposed permit.) Interested persons would have 15 days in which to raise substantive objections to the proposed fast-track modification. If no substantive objections were received, the modification would take effect. If substantive objections were received, the proposal would have to go through the permit modification procedure, including general public

notice, of 40 CFR Part 70. Objections would be evaluated by the Agency, using the criteria in Section 72.77, to determine whether they were substantive.

Under the second approach to fast-track modifications, the permittee would give public notice of its proposed new compliance option through publication in a journal (or newspaper) of national and general circulation. The permittee would also give actual notice to each interested person, on or after the permittee submitted the proposed compliance option to the Administrator. The notice would specify that all comments be submitted to the Administrator. The public would have 30 days to send comments to the Administrator. The Administrator would approve or disapprove the fast-track modification within 30 days after the end of the comment period.

EPA believes that either of these approaches would prove to be more expeditious than the permit modification procedures of 40 CFR Part 70. The first approach is more streamlined than the second, so long as no substantive objections are raised. The second approach would be quicker if the public were to raise objections. EPA is considering whether to: (1) promulgate the permit modification procedure of 40 CFR Part 70 only, (2) choose one of the options for fast-track modifications, or (3) promulgate both fast-track modification options into regulation and allow the permittee discretion to choose which option to use. The Agency requests comment on these approaches.

In addition, as was mentioned above, the Agency will be promulgating final Title V rules during the pendency of this rulemaking. The Agency, thus, also requests comment on whether any of the types of changes that would be subject to any of the modifications procedures in today's proposal could be handled under any procedures for minor permit amendments that may be established in the final Title V rule.

3. Administrative Permit Amendments. The Agency also proposes to adopt, for purposes of the Acid Rain program, the administrative amendment procedures set forth at 40 CFR Part 70. Changes to a permit, such as corrections of typographical errors, changes in names, addresses, and phone numbers, a change which requires more frequent monitoring at a source, and in most cases a change in ownership or operational control at a source are included under the administrative amendments procedures of 40 CFR Part 70. Today's proposal would add to that list: changes such as the activation of a compliance option which was previously conditionally approved in the original permit application; and changes to the designated representative, so long as a new certificate of representation is submitted pursuant to Subpart B. The administrative permit amendment procedure would also be used to incorporate or revise a reduced utilization plan that does not involve a compensating unit, so long as the plan meets all the requirements specified in the regulations at Section 72.43, and changes to a substitution plan that does not result in a previously unaffected unit becoming affected.

The Agency also proposes that the administrative permit amendment procedure be used to terminate an Acid Rain compliance option as authorized by the regulations. This approach would, however, be subject to the limitations on terminating options applicable to Phase I Extensions and Repowering Extensions, as well as the limitations on de-designating substitution units in Section 72.41, and on de-designating compensating units in Section 72.43.

In addition, the administrative amendments procedures would apply to incorporate alternative monitoring systems approved under 40 CFR Part 75 of today's proposal, and excess emissions offset plans pursuant to Section 411 of the Act approved by the Administrator according to procedures specified in 40 CFR Part 77 of today's proposal into a permit. The procedures for these two categories of actions by the Administrator include public comment. Further public comment would, therefore, be redundant.

EPA asks for comment on the scope of permit revisions appropriately made pursuant to the administrative amendments procedures.

4. Minor Permit Amendments. Under proposed 40 CFR Part 70 a minor permit amendment procedure is also authorized, to cover any proposed revision to a permit that is not a modification under Title I.[22] This procedure is primarily intended to provide sources with operating flexibility in their day-to-day operations. Because the Acid Rain program is an annual program which, by definition, provides ample flexibility with regard to variation in operating conditions throughout the year, EPA does not believe that this procedure would be necessary for most types of revisions that will be seen in Acid Rain program.

The changes that utilities might need to make rapidly generally would not involve any sort of notice or permit revision under the Acid Rain program. For example, operational changes such as fuel switching would not normally require any notice. The few types of changes that would need to be made rapidly and for which notice might be required are covered under the administrative or automatic permit amendment procedures (e.g., end-of-year allowance transactions amend the permit automatically upon recordation with EPA). The changes that would necessitate a permit revision with significant input from the permitting authority are, under the Acid Rain program, all long-term changes. Thus, EPA believes that a two month delay for approval of a new compliance option would not hinder the ability of sources to operate in a cost-effective manner. For example, a

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[22] The source would be required to notify the permitting authority 7 calendar days before the change is to occur. The rule would require the change to comply with all applicable elements of the Act relevant to the source. Under this procedure, the permitting authority has 7 days to notify the source if the change is not acceptable as a minor amendment, and it is then treated as a modification.

source may determine in the middle of the permit term that it is more cost-effective to make emissions reductions at a Phase II unit and to bring the Phase II unit in to Phase I as a substitution unit. Since allowances will be allocated on an annual basis, the source may specify whether the new allowance allocation is to be calculated retrospectively for that calendar year, or applied to the following calendar year. Any delay on the part of EPA in processing the revision (under the fast-track modification procedure, for example) would, therefore, not affect the source's ability to comply with the Act.

The Agency, therefore, believes that the minor permit amendment process will not be needed in the Acid Rain program. Thus, EPA is proposing that no revisions to the Acid Rain portion of a permit would be processed under the minor permit amendment procedure. However, EPA requests comment on the need for a minor permit amendment provision and specifically requests comment on the types of changes that would best be covered through minor permit amendments.

5. Automatic Permit Amendments. Today's proposal also provides that allowance transactions to or from a unit's Allowance Tracking System compliance subaccount that are properly recorded with EPA would automatically amend the permit. Title IV of the Act specifies that allowance transactions be treated differently from most permit revisions. The proposal reflects this statutory requirement. Allowance transactions are incorporated into permits as automatic amendments upon recordation by the Administrator. A detailed discussion of allowance transaction recordation can be found in the 40 CFR Part 73 preamble.

J. *Compliance Certification.*

Compliance certifications are a fundamental element of the Acid Rain program's implementation strategy. The term "compliance certification" is defined in today's proposal as a report signed and verified by the designated representative of the source's or unit's compliance or non-compliance with applicable requirements. The statutory authority for this requirement can be found in Section 114(a) of the Act (as amended by Section 702 of Act Amendments of 1990), which requires that the Administrator promulgate enhanced monitoring and compliance certification regulations, and in Section 504(c) in Title V of the Act, which requires that compliance certification requirements be included in each source's operating permit.

The Agency believes that heavy reliance on compliance certifications in the Acid Rain program will greatly increase flexibility, reduce the burden on sources of demonstrating compliance while maintaining the Agency's ability to ensure program accountability. They will also provide a helpful vehicle for resolving misunderstandings concerning applicable requirements before there has been a violation. This feature which should greatly increase program certainty for sources.

The strategy of relying heavily on certifications evidences a dramatic departure from the methods traditionally used to

determine compliance, i.e., on-site inspections and source-specific investigatory letters requiring the collection and submission of emissions data and operational reports. The Agency proposes that every Acid Rain program submittal be certified as to its truth and accuracy by the designated representative. As is discussed in Subpart B, only the designated representative can submit compliance certifications.

Compliance certifications are categorized in today's proposal according to frequency of submission, such as quarterly or annual. The proposal specifies the contents and submission dates for these certifications and reports. The submission deadlines are consistent with the Agency's proposal today at 40 CFR Part 73, specifying an end of year allowance transfer deadline for sources to consolidate data and conform their allowance accounts, and the emissions data reporting requirements of 40 CFR Part 75.

Some compliance certifications would be submitted on an irregular schedule to provide the Agency and the permitting authority with notice of an operational change pertinent to the Acid Rain program (e.g., shut-down of a unit for repowering). The proposal also requires the designated representative of an affected unit employing one or more Acid Rain compliance option to include in the annual, quarterly, and other reports, the compliance certifications specified in the sections of the regulation for the relevant compliance option. For example, certain statutory compliance deadlines are specified under the Phase I and repowering extension provisions. In addition, sources may specify implementation deadlines, for example, for putting into effect energy conservation measures under a reduced utilization plan or for phasing in allowance distributions under a substitution plan. This rule does not, however, contemplate the use of detailed schedules and increments not mandated by the statute or sought by the source.

One data requirement that the Agency believes is an essential program element during Phase I is heat input and generation information. This information is necessary to ensure compliance with the reduced utilization requirements of the program (addressed in today's preamble discussion of Section 72.43 and Subpart C), and to allow sources the flexibility to pursue their normal dispatching operations while ensuring that SO_2 emissions are accounted for in accordance with Section 403(d)(1) and (2) of the Act. The annual compliance certification for each Phase I unit would provide that if the unit has reduced utilization below its baseline, the designated representative must make one or more of several demonstrations to account for the SO_2 emissions that would have resulted from load shifts. The annual compliance certification would also require the designated representative to certify whether any reductions in utilization caused the unit to be subject to the planning requirements for reduced utilization in Section 72.43 of Subpart D.

1. Need for Information. Some information proposed to be required in annual compliance certifications is information that the Agency could obtain from other sources. This proposal contemplates, however, that compliance certifications be self-contained documents to the extent feasible. First, this will facilitate more expeditious review of a source's compliance status. In addition, the Agency believes that requiring the designated representative to report this information and certify emissions totals will provide an added verification of the data, and minimize the opportunity for disputes concerning the compliance status for each unit. The Agency requests comment on the scope of the information required to be included in the annual compliance certification.

K. *Phase I Extension Early Ranking Procedures.*

Subpart L would provide the procedures for early ranking of Phase I Extension plans submitted under Section 72.42 of today's proposal. Subpart L addresses two concerns: (1) the statutory mandate in Section 404(d)(3) of the Act that submissions for Phase I Extensions be considered by the Administrator "in order of receipt", and (2) the need of the regulated community to know as early as possible whether they will be eligible for Phase I Extension allowances. Because of the economic benefits a source would derive from a Phase I Extension, some estimates indicate that the Phase I Extension allowance reserve of up to 3.5 million tons, mandated by Section 404(a)(2) of the Act, may be oversubscribed. Many sources can, therefore, be expected to apply for Phase I Extension allowances in a short period of time, making it difficult to determine the "order of receipt" of a proposed Phase I Extension plan submitted under Section 72.42 by relying exclusively on postal delivery services.

The Agency is, thus, proposing an Early Ranking procedure for determining the order in which to act on Phase I Extension applications. The Agency proposes to use a voice-mail telephone queuing procedure followed by a written Phase I Extension Early Ranking application submission mailed not later than midnight of the same business day of the phone queue. The "order of receipt" established by the Early Ranking procedure would be conditional. In particular, it would be conditioned on timely submission by the designated representative for each applicant, in accordance with the procedures proposed in Subpart C and Section 72.42 of Subpart D of today's proposal, of a complete and approvable permit application and proposed compliance plan by the Phase I permit application deadline of February 15, 1993 specified in Section 408 of the Act.

1. Industry's Interest in an Accelerated Procedure. Information available to EPA indicates that it takes three years to design, construct, and install qualifying Phase I Extension control technology (i.e., 90% controls). The Agency believes that the Early Ranking procedure proposed today is necessary to provide sources considering installing such controls with a reasonable idea of whether they will be eligible for Phase I Extension allowances, and to allow utilities enough time to

install the qualifying Phase I technology before January 1, 1997. (See preamble discussion of Section 72.42 of Subpart D, of today's proposal for a more detailed discussion of Section 404(d) of the Act.)

2. Overview. Subpart L presents a voice-mail phone queuing procedure which sources seeking a Phase I Extension may use for obtaining an early ranking.[23] Subpart L also describes procedures for EPA action on Early Ranking applications. Currently available voice-mail systems can receive hundreds of calls within a short period of time, and rank them in order of incoming calls by milliseconds. The Agency proposes this approach because it is consistent with the statutory language of "order of receipt", and it affords an expeditious minimally burdensome way for giving applicants critical information regarding their eligibility for extension allowances at an early stage in the program.

As described in Section 72.500, Subpart L applies only during Phase I, and only to existing affected units for which a Phase I Extension is sought pursuant to Section 72.42 of today's proposal. Consistent with other provisions of Part 72, the designated representative(s) for the unit(s) in a proposed Phase I Extension plan would be the sole person(s) with authority to participate in the Early Ranking procedure under this subpart.

Under today's proposal, the designated representative for each affected unit that would be governed by the Section 72.42 Phase I Extension plan would submit a certificate of representation. EPA proposes to issue a secure designated representative identification number to each designated representative within 30 days of receipt of a certificate of representation. (See, Subpart B of today's proposal). These identification numbers are required to participate in the Early Ranking phone queuing procedure. The notice would include instructions for the designated representative to follow in order to participate in the phone queuing procedure. These would include procedures for registering a secure application ID# with EPA, for obtaining a secured phone number to call on the date of the phone queuing, the date and time of the phone queuing, instructions on how to enter information into the voice-mail system, and instructions and forms for the follow-up mailing.

Section 72.502 describes the Administrator's action on Early Ranking applications. Following the ranking, allowances would be conditionally awarded by the Administrator based on the order of each Early Ranking application as established by the phone

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[23] Sources that did not wish to participate in the Early Ranking procedure could wait until submitting their permit application, as provided in Subpart C of today's proposal, to submit a proposed Phase I Extension plan. The proposed plan would, however, have to be disapproved if the extension allowance reserve were oversubscribed.

queuing procedure, until all ranking applications were acted on or until the reserve appeared to be oversubscribed.

Because EPA recognizes the need for applicants to know their conditional ranking as soon as possible, Subpart L proposes that EPA would notify applicants within 30 days after the conditional ranking is established through the phone queuing procedure. Allowance awards would be calculated based on the formula described in Section 72.42.

The allowance awards would be conditional in several respects. First, they would be subject to an applicant's meeting the full requirements for timely submitting a complete permit application and Phase I Extension plan that are set forth in Subpart D, Section 72.42 and Subpart C of today's proposal. The Administrator's action on Early Ranking applications would also be conditional subject to subsequent corrections to the information contained in the ranking application and to the results of challenges to the rule, if any are brought. Moreover, if Subpart L is promulgated in final in advance of the rest of the core rules (Parts 72, 73 and 75), the Administrator's action on Early Ranking applications would be subject to the designated representative modifying the application, as necessary, to conform to the Part 72 rule as finally promulgated. One provision which would be promulgated at Part 73 after the Early Ranking procedure is implemented, and which could significantly affect the allowance awards for each Phase I Extension plan, is the procedure for annualizing Federally enforceable allowable emissions limitations.

The ranking provided for in Subpart L would, therefore, not constitute either an approval of a proposed Phase I Extension plan or an award of Phase I Extension allowances. Thus, the ranking provided for by Subpart L would be presumptive, and conditional on the Administrator's review of, and action on, a complete Phase I Extension plan and approvable and timely permit application pursuant to Subpart C and Section 72.42. Likewise, Phase I Extension allowances would be awarded pursuant to the ranking procedure on a conditional basis only. The awards would be subject to the timely submission of the permit application and compliance plan, and to yearly demonstrations that the qualifying Phase I control technology for the control unit and the source has achieved 90% removal of sulfur dioxide (See, Section 72.42). Actual approval of Phase I Extension plans and awards of Phase I Extension allowances would be made pursuant to the provisions of Section 72.42. The conditional ranking would, however, give applicants greater certainty regarding the approximate distribution of the Phase I Extension allowance reserve, assuming all subsequently required submissions and steps are achieved. Any allowances returned to the reserve by the withdrawal of an application or by the failure of an applicant to meet all of the conditions of this subpart and Section 72.42 of the rule would be conditionally awarded to the next application in the ranking order.

3. Other Approaches Considered for Determining "Order of Receipt". (a) *Modified Phone Queue Approach.* Under another approach the Agency is considering the designated representative would submit an Early Ranking application to EPA by certified mail when he or she submits the certificate of representation. EPA would begin accepting applications 15 days after the day the rule is promulgated in final in the FEDERAL REGISTER. Once an Early Ranking application was received, EPA would notify the applicant within 30 days whether the application was complete. An application would not be deemed to have been complete or received unless and until the certificate of representation required by Subpart B was received by the Administrator.

All complete Early Ranking applications received by EPA on a given day would be considered to have been received at the same time. For applications received on a particular day that did not result in the Phase I Extension allowance reserve being oversubscribed, the notification of receipt would specify a conditional award of allowances. If, however, the applications received on a given day resulted in an apparent oversubscription of the Phase I Extension allowance reserve, a phone queuing procedure would be used to determine the "order of receipt" for the tied applications.

Beginning on the day of apparent oversubscription, for each application received on a day when more than one application was received, the Administrator's notification of completeness would specify that a phone queuing procedure would be used to determine the application's "order of receipt" for the tied applications. The notification would indicate the date and time (not earlier than 30 days and not later than 60 days after the date of the apparent oversubscription) when the phone queuing procedure would be carried out. In addition, the Administrator would issue with the notice procedures for registering a secure application identifier number for use during the phone queuing procedure. The period between the day of oversubscription and the day on which the phone queuing for that day was scheduled to take place, would provide each applicant an opportunity to decide whether to withdraw the application and proceed with other compliance options. Applicants would be able to elect not to participate in the phone queuing.

(b) *Lottery.* Another option considered by the Agency is a chance drawing or lottery approach. As with the modified phone queuing approach, under this approach, the designated representatives for all applications received on the same day beginning on the day of oversubscription would be notified of the tie, and each applicant would be informed of the procedures for registering a secure application identifier number. The designated representatives would, thereafter, have 30 days to decide whether to participate in a chance drawing. Designated representatives that did not notify EPA in writing within 30 days to proceed with the chance drawing would be deemed to have withdrawn their applications. The chance drawing, using the application identifier, would be used to randomly establish the

individual ranking of each tied application for which an election to participate was made. The designated representatives for participating applicants could be "present" at the drawing at their option.

(c) *Date Stamp.* Under another approach, under consideration for determining the "order of receipt" of Phase I Extension Early Ranking applications, applications would have to be submitted by certified mail. These would be date/time stamped by EPA in the order they were received at the location of the date stamp machine. The EPA time clock would determine each application's "order of receipt".

(d) *Stand-in-Line.* The Agency considered and is rejecting a stand-in-line approach to determining "order of receipt". Under this approach, applicants would have to deliver Early Ranking applications in person, and the rule would specify a date and time for applicants to begin submitting their applications. This approach, however, presented major logistical problems for the applicants, who would be required to wait in line, and for the Agency.

(e) *Pro Rata.* Another approach that was proposed to EPA, but is rejected by the Agency, was a pro rata distribution of reserve allowances. As in the modified phone queue and lottery approaches, this option would have provided for a window of submission that was one day long, so that any application received during a given day would be considered to have been received at the same time. The pro rata approach is also similar to the modified phone queue and lottery approaches discussed above in that, beginning on the day the applications received oversubscribed the reserve, a 30-day cooling-off period would be observed during which any applicant could choose to withdraw their application. The pro rata approach differs from the modified phone queue and lottery approaches, however, in that after the 30-day cooling-off period, the Administrator would award any allowances remaining in the reserve on a pro rata basis to the remaining applicants.

In considering this option, the Agency recognized that distributing reserve allowances pro rata to more applicants, rather than giving the full amount requested to fewer applicants, might potentially encourage the installation of more control technology. However, the allocation scheme ultimately adopted by Congress in Section 404(d) -- including the requirement that applications be acted on and allowance awards made "in order of receipt"--is very specific in requiring a sequential distribution of allowances from the reserve, rather than a distribution of a share of allowances to all applicants. In addition, a pro rata distribution would be substantially more time consuming than the approach proposed today. Nor would today's proposal preclude side-bar pro rata agreements between applicants, should utilities wish to pursue such arrangements. EPA would have no involvement, however, with such agreements.

4. Early Rulemaking. EPA is considering accelerating final promulgation of portions of today's Part 72 proposed rulemaking

in order to implement the Early Ranking procedures as soon as possible. The portions of today's proposal which would be included in an accelerated final package include Subpart L, Subpart A (general provisions), Subpart B (designated representative certification procedures), and Section 72.42 of Subpart D. In the event comment on those subparts is favorable, the Agency would be in a better position to move forward with an accelerated rulemaking and early implementation of the Early Ranking procedure. Significant adverse comment on these provisions would make an early rulemaking less feasible.

V. Sulfur Dioxide Allowance System

A. Allowance Rule Background and Summary

1. Applicability

Today's proposal contains a statement of applicability to inform the public as to who is subject to the requirements of Part 73. First, Part 73 applies to owners and operators of sources of sulfur dioxide that are affected sources pursuant to Title IV and §72.7. Such affected sources, including new sources and sources that "opt in" pursuant to §410 of the Act and Part 74, are required to hold allowances sufficient to offset their sulfur dioxide emissions. Most existing utility units and some new utility units will be allocated allowances by EPA pursuant to Part 73, Subpart B, Part 72, Subpart D, and Part 74. Most new sources will not be allocated allowances, but will be required to purchase allowances. This Part also applies to independent power producers (IPPs) as defined in §416 of the Act (except those exempted under §405(g)(6) of the Act), and in Part 73.74 of the Auctions, Direct Sale and IPP Written Guarantee Proposed Regulations. IPPs with written guarantees have priority in the purchase of allowances from the EPA Direct Sale.

Subject to the opt-in regulations, which will be proposed at a later date, any small diesel refinery as described in §410(h) of the Act will also be covered by regulations in this Part.

Finally, this Part applies to any person who purchases, holds, and trades allowances as allowed in §403(b) of the Act. The term "person" is defined in §302(e) of the Act and includes an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

2. Function of Allowances in the Acid Rain Program

As discussed in sections II and III of this preamble, the fundamental compliance mechanism for the SO_2 reduction program is an innovative system of marketable allowances. Since allowances are the fundamental instruments of SO_2 compliance, the Act requires EPA to establish a system for tracking allowances. Accordingly, the Allowance Tracking System must be reliable, and it must be designed and must function in a way that does not impair the ability of affected units to use allowance transfers to maximize efficiency in their compliance strategies.

3. Statutory Authority for the Proposed Allowance System

Section 403 of the Act creates the primary authority for the regulations proposed today. Excepting certain provisions in effect only through the year 2009, §403(a) of the Act mandates that EPA allocate allowances for each affected unit in an amount equal to its statutory SO_2 emissions limitation requirement (expressed in tons), provided that no more than 8.95 million allowances are allocated annually after January 1, 2000.

Section 403(b) of the Act authorizes the transfer of allowances between and among

units through the "designated representative" for the owners and operators of each unit, and between and among any other person holding allowances. Section 403(b) also requires EPA to promulgate regulations to "establish the allowance system prescribed under this section, including, but not limited to, requirements for the allocation, transfer, and use of allowances under this title." Pursuant to §403(b), the regulations are to "prohibit the use of any allowance prior to the calendar year for which the allowance was allocated," while providing for "unused allowances to be carried forward and added to allowances allocated in subsequent years." Section 403(b) further requires "written certification of...transfer[s], signed by a responsible official of each party to the transfer...." Finally, paragraph (b) of the section states that "recorded pre-allocation transfers shall be deducted by the Administrator from the number of allowances which would otherwise be allocated to the transferor and added to those allowances allocated to the transferee." In addition, §403(d) of the Act requires EPA to promulgate "a system for issuing, recording, and tracking allowances, which shall specify all necessary procedures and requirements for an orderly and competitive functioning of the allowance system."

At the same time, §403(f) of the Act provides, in part, as follows:
"Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such State regulation or as limiting regulation (including any prudency review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under that Act. Nothing in this title shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established."

Section 408(i) of the Act requires a designated representative of the owners and operators of each affected unit to "file[] a certificate of representation with regard to matters under this Title, including the holding and distribution of allowances and the proceeds of transactions involving allowances." In the case of multiple owners, such certificate must address the holding and distribution of allowances and the proceeds of transactions involving allowances.

Finally, when a unit's SO_2 emissions exceed the number of allowances held for the unit, §411(b) of the Act, in addition to imposing a $2,000 penalty for each ton (or fraction of a ton) of exceedance, requires EPA to "deduct allowances equal to the excess tonnage from those allocated for the source for the calendar year, or succeeding years during which offsets are required, following the year in which the excess emissions occurred."

4. Summary of Today's Proposed Rule

(a) Regulatory Approach to the Allowance System

The design of the allowance trading and tracking system proposed today reflects the implicit roles Congress devised for the Agency, other regulatory agencies, and the market participants.

EPA views its role as filling three critical needs of the allowance trading market: (i) neutral, low-cost rules of exchange; (ii) basic tracking information on allowances; and (iii) certainty in the identification of a person's authority to transfer allowances. EPA therefore

approached the trading rules with the view that the system should be simple to understand and should impose minimal burdens on the participants. Under today's proposal EPA would provide the authoritative record of allowance account holdings and transfers, in order to fulfill its implied statutory mandate to assure certainty for the allowance market and its express mandate to ensure compliance with SO_2 emissions requirements. These roles are clearly laid out in §403 of the Act and are implicit in Congress' direction that EPA establish an orderly and well-functioning market.

Similarly, today's proposal reflects the Act's express limitation on intrusions by EPA's regulations in areas of economic regulation of the electric utility industry that are already carried out by the Federal Energy Regulatory Commission (FERC) and State rate regulators (Public Utility Commissions, or "PUCs"). Such regulatory authorities will play a useful role in reviewing long-range plans of utilities as they comply with the requirements of the Acid Rain program.

The market participants themselves, which include both affected units and others, are the only parties who can "make the market work" by providing the various private commercial arrangements markets need to function efficiently. Indeed, in previous emission trading programs, the private market has created all necessary contractual and informational functions for the orderly operation of the markets. In view of this record and the ultimate exclusive role of private actors in determining the level of activity and efficiency of the market, it is EPA's belief that the EPA allowance system must provide flexibility to participants and be as unconstrained by regulatory authority as is reasonable while meeting the stated environmental protection objectives of the Act. Therefore, in designing the proposed regulations for Part 73, EPA eschewed any option that would cast the Agency in new purportedly "market-making" roles beyond those expressly prescribed by the Act.

(b) Overview of Proposed Rule

As proposed here in Part 73, pursuant to §403(b) and §403(d) of the Act, EPA will establish a system of allowance accounts for each affected unit and for any other person likely to hold allowances. Allowances initially allocated by EPA for each affected unit pursuant to §§ 403(a), 404, 405, 406, 408, 409 and 410 of the Act and proposed Parts 72, 73 and 74 will be held in these accounts. Transfers of allowances recorded with EPA will be effected by deducting allowances from the transferor's account and adding them to the transferee's account. To determine whether or not a unit has met its annual emissions control requirements, EPA proposes to deduct, at the end of each year from each unit's account allowances usable in that year in an amount equal to the unit tons of SO_2 emissions for the year, as recorded and reported pursuant to the emissions monitoring regulations proposed today at Part 75 and Part 72, Subpart K. If a unit's allowances exceed its emissions of SO_2 for the year, allowances remaining in the account after each year's deduction will be carried forward and banked in the unit's account for the following year. If the unit's total emissions of SO_2 for the year exceed the number of allowances usable in the year held in the unit's account, then EPA proposes to deduct, at the end of each year from each unit's account, allowances usable in that year for the following year in an amount equal to the unit's excess emissions, pursuant to an excess emissions offset plan submitted for the unit under Part 77.

Part 73 of the proposed Acid Rain rules sets forth the procedures for establishing

accounts, and the procedures applicable to EPA and account holders in operating the account system.

(c) Design of the Tracking System

For an affected unit, each allowance account would include a "compliance subaccount" (and for accounts held by others, a "current year subaccount"), for allowances that may be used for compliance purposes in that calendar year, and a subaccount for each future calendar year. For example, in Phase I each unit would have a separate subaccount for 1995, 1996, 1997, 1998, and 1999. The latter subaccounts will reflect allowances that may be used for compliance in each subsequent specified year. Each compliance and future subaccount initially would reflect the number of allowances that the Act authorizes EPA to allocate for each year for the unit. Thereafter, each subaccount's allowances would be credited or debited to reflect any allowance transfers. EPA proposes to assign a unique identification number for each allowance, which will reflect the calendar year for which the allowance may first be used for purposes of compliance ("the compliance use date").

EPA proposes to provide for the automatic banking of allowances by retaining in the compliance subaccount any allowances remaining in the subaccount that are not deducted to meet the unit's emissions limitation requirements.

The proposed rule requires EPA to establish an Allowance Tracking System account for every existing affected unit, even if the unit is affected only in Phase II, by no later than January 30, 1993. This proposed action permits EPA to record in the accounting system any allowances Phase II units may acquire, through the allowance auction or from a private seller, during Phase I (i.e., 1995-1999) and allows the Phase II units to trade their Phase II allowances immediately. In addition, EPA would establish accounts for new units, and for SO_2 sources that elect to participate or "opt in" to the allowance system, by becoming affected units for purposes of Title IV (under Part 74 and §410 of the Act). Finally, any person may apply to EPA to establish a non-unit account for purposes of holding allowances, after the effective date of the Part.

All matters pertaining to the account would be carried out by a person designated and certified as the authorized account representative for the account. In the case of unit accounts, the authorized account representative would be the designated representative for the unit, as established pursuant to the Acid Rain Permits regulations proposed today at Part 72, Subpart B.

As noted above, EPA proposes to determine a unit's compliance by deducting from the unit's compliance subaccount allowances equal in number to the SO_2 emissions tonnage reported for the unit pursuant to Part 75 and Part 72, Subpart K for each year. EPA proposes today to establish as an "allowance transfer deadline," January 30 of the calendar year following the year for which compliance is being established, as the last day on which allowance transfers may be submitted to EPA for recordation in a compliance subaccount for use in meeting a unit's SO_2 emissions limitation requirements for the year.

After the allowance transfer deadline, if the unit's SO_2 emissions in tons exceed the number of allowances recorded in the unit's compliance subaccount, EPA proposes to "freeze," for purposes of subsequent transfers from the unit's account, allowances in the unit's compliance subaccount for the next year (i.e. the year following the calendar year in which the excess occurred), in an amount equal to the unit's excess emissions tonnage. The

"freeze" would be lifted after EPA deducted allowances from the unit's compliance subaccount for purposes of offsetting the excess emissions, pursuant to the unit's approved excess emissions offset plan submitted pursuant to §411 of the Act and Part 77.

EPA will make available for public review the information, in summary form, contained in each allowance account.

(d) Annual Timeline for Subaccounts

The compliance requirements of the Acid Rain Program are on a calendar year basis, under the proposed rules today. However January 30 of each year (the "allowance transfer deadline") will be the last day for submitting requests to transfer allowances to compliance subaccounts for purposes of meeting sulfur dioxide emissions requirements for the preceding calendar year. Following that date, EPA will record all requests to transfer allowances submitted by the allowance transfer deadline and will then deduct allowances from the compliance subaccount, equal in amount to the unit's SO_2 emissions tonnage for the year, reported pursuant to Part 75 and Part 72, Subpart K in order to determine compliance for what, at that point, will be the preceding calendar year. Any allowances remaining in the compliance subaccount after the deductions will remain in the subaccount for the following calendar year and remain there until transferred, or deducted for compliance in a subsequent year. Once deductions have occurred, EPA will also replenish the compliance subaccount by adding to it, allowances in the future subaccount for what is now the current calendar year. Following this step, EPA will begin recording for the compliance subaccount transfers of allowances whose compliance use date is what, at that point, will be the current calendar year or earlier.

(e) Recordation of Transfers

In the proposed rule, the exchange of allowances between account holders is made by submitting to EPA a request to record the transfer of allowances from one account to another. Until allowance transfers are recorded by EPA in a unit's account, they will not be available for meeting the unit's SO_2 emissions requirements. This is true regardless of what any commercial contractual obligation between two units to transfer allowances may be. Submissions to EPA of requests to record transfers may specify the identification numbers of the allowances to be transferred. As required by the Act, the proposed rule prohibits the transfer of an allowance usable in a specified calendar year to an allowance subaccount for an earlier year. In addition, EPA proposes not to record the transfer of any allowance if the allowance as specifically identified by its serial number in the transfer request does not appear in the transferor's account. Apart from this exception, EPA will record any transfer of an allowance from a unit's compliance subaccount without regard to the SO_2 emissions reported for the unit as of the date of the transfer. However, each transfer submitted for recordation that involves a unit account will be required to include an acknowledgement by the authorized account representative that EPA's recordation of the transfer shall not affect the unit's continuing legal obligation to comply with its requirements to hold allowances usable in that year in an amount equal to, or greater than, the unit's SO_2 emissions tonnage for the year.

(f) Timeline of Allowance System Activities

Following the final promulgation of this rule and of each unit's Phase II allowance allocations, EPA will establish an Allowance Tracking System account for each existing

affected unit, including those that will not become affected until the year 2000. Each account will include a subaccount for each year, beginning in 1995, until at least 2025. The owners and operators of each unit may select a designated representative for the unit and at any time after promulgation, the designated representative may submit a certificate of representation in accordance with Part 72, Subpart B. The designated representative for a unit shall be the authorized account representative for the unit's account. As soon as a certificate of representation is submitted, EPA will record any allowance transfer submitted by the designated representative, provided that the transfer meets the requirements of the allowance transfer regulations. In addition, any person may open a non-unit Allowance Tracking System account at any time after EPA establishes accounts for existing affected units. Draft forms are published today as part of the proposed rule. EPA may choose not to publish forms in the rule at promulgation.

By no later than December 31, 1991, EPA is required under §403(a) of the Act to propose a list stating the number of allowances to be allocated by EPA to each Phase II affected unit, apart from any allocations under any compliance option in Part 72, Subpart D. By no later than the end of 1992, EPA must promulgate a final list of allocations. The final list for Phase II allocations is subject to mandatory revision by EPA in 1998, in order for EPA to offset the allowances allocated for units with approved repowering compliance plans pursuant to §409 of the Act.

B. *Allowance Tracking System*

1. Function of Accounts

As proposed, the Allowance Tracking System (ATS) accounts will be the official records for allowance allocations, holdings and transfers, and will be used to track each unit's compliance. Initial allowance allocations, using calculations to be promulgated in Part 73, Subpart B (at a later date) and reflecting each unit's statutory SO_2 emissions limit, as well as allocations pursuant to Part 72, Subpart D, provide the starting point for tracking allowances. All allowance transfers to and from the accounts will be recorded to track the unit-by-unit holding of allowances as they are transferred. For the purposes of determining compliance EPA proposes to deduct allowances from each unit's compliance subaccount in an amount equal to its annual SO_2 emissions in tons as reported pursuant to Part 75 and Part 72, Subpart K.

2. Subaccounts

EPA proposes that each unit account include a compliance subaccount. The compliance subaccount will hold all allowances that may be used for purposes of meeting the unit's SO_2 emissions limitation requirements in the current year. Each account will also include a future year subaccount for each of the 30 years following the current year, which would reflect allowances usable for compliance purposes in each specified future year.

The proposed system, which creates a record both of current and future allowance holdings, is compatible with the decision-making and planning functions of utilities. Long-

term planning is characteristic of utility business practices in meeting their electric generation obligations and is nearly indispensable in meeting emissions limitations. For the latter purpose many utilities will rely on the installation of control technology, which must be planned on a long-term basis, or on switching to lower SO_2-emitting fuels, which also requires long-term contractual commitments and, in some cases, equipment modifications. In general, 30 years is considered to be an average operating life of an electric utility unit, not including any repowering or life extension. Thus, EPA believes that future year subaccounts spanning 30 years would facilitate long-term planning for meeting emission requirements within the standard operating life of a unit. Furthermore, transfers involving allowances to be allocated in years after the 30 year period tracked in the ATS may be submitted for recordation by EPA at any time. The transaction would be noted in the transferring accounts and then would appear in the applicable future year subaccounts at the time they were added to the ATS.

(a) Compliance and Future Year Subaccounts

Separating allowances between those usable in the current year and those usable in future years is intended to implement the Act's prohibition against the use of any allowance prior to the calendar year for which the allowance was allocated. Because only allowances recorded in a unit's compliance subaccount can be used to offset a unit's emissions, the proposed allocation and account structure would preclude the use of future year allowances in offsetting current year emissions.

EPA is proposing that the future year subaccounts cover at least the first 30 years following the current year, beginning with 1995, and continue to cover a 30-year period following each successive year. This means that at any point in time, any account holder would be able to view a unit's allowance balances for each year for each of the next thirty years. Any transfer of an allowance for any of the years in the 30-year period can be recorded in the Allowance Tracking System.

(b) Allocations in Future Year Subaccounts

As proposed today, future year subaccounts will reflect allowances allocated for each unit for each future year in the proposed 30-year timespan for subaccounts. At first, these allocations will reflect each unit's statutory emissions limitation requirements pursuant to the Act's §403, §404 Table A (as modified by §416) for Phase I, and §405 for Phase II, as well as certain additional allocations prescribed in the Act. Subpart B of Part 73 and Appendices A and B of Part 72 will provide these allocations.

Title IV of the Act and proposed Part 72 also provide for alternative methods of compliance. In Phase I certain units may obtain additional allowances for up to two years. Pursuant to the Act and proposed §72.42, EPA will allocate additional allowances for those units that qualify. In addition, Phase I units may meet their SO_2 emissions limitation requirements by substituting emissions reductions made at other units, not listed on Table A of §404 of the Act. Here, too, EPA is required by the Act and proposed §72.41 to allocate additional allowances pursuant to substitution plans. Allowances are also used to implement Phase I reduced utilization plans when emissions reductions at Phase I units are achieved by shifting electrical generation to units not otherwise affected in Phase I.

The Act also permits additional allocations for Phase II units that use qualifying repowering technologies, pursuant to §409 of the Act and proposed §72.44. In addition, the

Act (and proposed Subpart F) authorizes EPA to allocate allowances to utilities that adopt certain conservation and renewable energy measures or technologies. Section 410 of the Act authorizes EPA to allocate allowances to sources who "opt in" to the allowance program, and certain small diesel refiners. Finally, Subpart E, proposed on May 23, 1991, will provide for the allocation of a reserve of allowances for those who purchase them at public auction or through a direct sale.

Today's proposal provides that future year subaccounts will reflect all such additional allowance allocations as they are made for affected units pursuant to Part 72 compliance plans, or to other applications required by proposed Part 73. Again, allowance holdings are integral to utilities' compliance strategies. Since these are usually formulated on a long-term basis, EPA believes that it is essential that the tracking system reflect all allowance allocations for each year, as soon as they are made, in order to facilitate utilities' mapping of their long-term strategies.

(c) Transfers in Future Year Subaccounts

EPA proposes to implement the statutory mandate to record "pre-allocation transfers" by following the method, prescribed in §403(b), of the Act of "deduct[ing]...from the number of allowances which would otherwise be allocated to the transferror, and add[ing them] to those allowances allocated to the transferee." This will be done simply by adding and deducting allowances in the relevant future year subaccount.

This process enables the Allowance Tracking System to reflect a unit's allowance holdings for any future year as soon as a transfer is recorded. As a result, at any given point in time, there will be up-to-date and reliable information about units' current and future year allowance holdings. Again, this appears to EPA to be indispensable to providing the information and certainty utility managers and others require in planning compliance and incorporating allowance transfers in their planning.

Specifically, EPA expects utilities to execute long-term "forward" contracts providing for the transfer of allowances for a period of years well beyond the time at which such contracts are negotiated. Not only would such contracts be indispensable to conforming compliance plans, but they would assure sellers of reliable revenues and buyers of a supply of allowances at a known price, thus providing both parties with a method for managing and sharing risks associated with fluctuations in allowance price and availability.

Apart from the method for recording the transfer of an allowance with a compliance use date more than 30 years beyond the current year, which is discussed below, EPA considered, but proposes to reject, an alternative scheme of recording transfers which would have recorded the submission of future year allowance transfers but delayed the recordation or effectuation of the transfers until (1) the subject allowances were to be recorded in the compliance subaccount at the beginning of the current year, and (2) any allowance deductions were made from the transferor unit's account, pursuant to any excess emissions offset plans under §411 of the Act and Part 77. The rationale for this approach is that it would come closer to guaranteeing that there would also be a sufficient number of allowances in a unit's future year subaccount to offset a unit's excess emissions, as required by §411. At the very least, this alternative scheme would preclude the possibility that allowances required to be deducted to offset excess emissions would have been transferred to another unit, leaving the transferor account without sufficient allowances to meet the

offset deduction requirement.

EPA proposes to reject this alternative for several reasons. First, the proposed approach makes it easier for utilities to use the Allowance Tracking System as a source of reliable information for purposes of planning compliance and exploiting the efficiency opportunities of allowance transfers. Under the proposed approach, each Allowance Tracking System unit account will display each unit's allowance holdings for each year, current and future, and each year's holdings will reflect recorded allowance transfers. The alternative, in contrast, would require those who needed information concerning units' future year holdings -- such as would-be purchasers or sellers of allowances, including other utilities seeking to establish collective compliance strategies -- to calculate their own and other units' future allowance holdings based on listed transfers.

Second, under the rejected approach, those transfers would be subject to uncertainty, since they would not be effectuated until after allowances had been deducted for purposes of offsetting excess emissions pursuant to §411 of the Act. As a result, allowance transfers that had been agreed upon could be negated, at least in part, if, pursuant to §411, EPA deducted allowances from the transferor's subaccount prior to effectuating a transfer from the subaccount. EPA acknowledges that private parties engaging in allowance transactions could provide, by contract, to indemnify the transferee in the event that a pre-transfer deduction of allowances for offset purposes defeated the transfer in whole or in part. EPA concluded, however, that both the mandate in §403(b) of the Act to record pre-allocation transfers as well as the underlying policy of Title IV militate against a recordation rule that would force the allowance market to absorb the transaction costs associated with contractual indemnification. While §411 of the Act imposes severe penalties on those units whose SO_2 emissions exceed the number of allowances they hold, the compliance planning provisions of §408(b) of the Act suggest a policy of affording all units maximum flexibility in meeting their emissions limitation requirements, at least until such time as they violate those requirements. Because of the uncertainty it would cause and the transaction costs associated with overcoming that uncertainty, delaying the recordation of transfers involving future year allowances would have the effect of penalizing all units, not just those violating their emissions obligations, and could interfere with utilities' ability to exploit the full cost-saving potential of the allowance market.

At the same time, EPA does not believe that the rejected approach concerning future year allowance transfers would significantly enhance the compliance scheme embodied in §411 of the Act. There is little likelihood, EPA believes, that the proposed rule would foster frequent situations in which units with excess emissions had insufficient allowances, as a result of previous transfers, to permit EPA to make deductions pursuant to §411 of the Act and Part 77.

3. Non-Unit Accounts

EPA is also proposing to establish accounts for persons other than affected units because §403(b) of the Act expressly authorizes "any person," in addition to the designated representatives for affected units, to hold and transfer allowances. These non-unit accounts would provide the vehicle through which persons, such as brokers or utility power pools,

seeking to aggregate allowances allocated for individual units could hold and transfer allowances. Non-unit accounts would include a current year subaccount and subaccounts for each of the 30 future years following the current year, beginning with 1996.

EPA is proposing to establish a non-unit account following the receipt of a new account application. The application would be required to include a certification by the authorized account representative. This is intended to protect ownership interests in any allowances held in the account, through disclosure of information and verification that the owners have agreed to the authorized account representative.

Both the legislative history of §403(b), of the Act and EPA analysis suggest that brokers, investors and other market-makers may play a crucial role in facilitating allowance transfers. [See S. Rep. No. 228, 101st Congress, 1st Sess., p. 320 (1989).] In addition, as suggested by §403(d)(2) of the Act, groups of units may choose to pool some or all of the allowances allocated for each unit. A non-unit account, created by the owners of such units but separate from the individual unit accounts, may serve as the mechanism for pooling their allowances. Since these allowance brokering and pooling functions are intended to facilitate utilities' efforts to maximize the efficiency of their compliance strategies, the Allowance Tracking System accounts through which these functions may be carried out should be integrated with the account system established for affected units. Accordingly, EPA proposes establishing non-unit accounts that parallel unit accounts, with multiple future-year subaccounts.

4. Identification Numbers for Allowances

EPA is proposing that each allowance be identified by a unique number that would include digits identifying the allowance's compliance use date, i.e., the first year for which it could be used. Members of the public have suggested that such a unique number identifying each allowance would enable utilities to structure transfers in order to ensure favorable accounting for purposes of regulatory rate and tax treatment. At the same time, without this unique number and the accounting procedures it would facilitate, the proceeds of allowance transactions might be taxed or treated for ratebase purposes in a manner that would discourage transfers or otherwise create implicit disincentives for adopting innovative or cost-efficient compliance strategies.

EPA believes that the potential for favorable financial accounting and tax treatment that may be tapped by the use of unique numbers could enhance utilities' confidence in the allowance market as a source of cost savings. Increased activity in the market that might ensue from this heightened confidence, in turn, might lower overall compliance costs. These cost savings for affected units could more than offset any additional administrative burden or cost to EPA and the affected parties associated with adopting serial numbers. Furthermore, representatives of the Chicago Board of Trade, which recently announced its intentions to create an allowance exchange, have advised EPA that the development of any organized commercial exchange would be greatly assisted by EPA's serialization of allowances, enabling interested parties to verify and track individual allowances through the course of commercial transactions. The Chicago Board of Trade noted that serialization is always used for bonds, commodities, and other tradeable debentures.

At the very least, EPA believes that giving each allowance a unique number provides flexibility to allowance holders in determining compliance strategies. The ability to distinguish one allowance from another could enable allowance holders to maintain records of the different costs incurred in acquiring or generating excess allowances, such as through emissions reduction, energy conservation measures, or other compliance strategies. This could aid utilities in demonstrating the basis for offsetting the economic gains received from the sale or utilization of particular allowances. Finally, including digits reflecting the compliance use date of each allowance would facilitate the ability of the buyer to ensure that an allowance could be used in a particular year.

EPA acknowledges that it holds some reservations in making this proposal. In the absence of formal identification of allowances by EPA, allowance holders could readily establish their own allowance-numbering system for tax and internal record-keeping purposes. Inventory systems created by each utility could serve some of the same financial ends that would be advanced by means of the proposed identification of unique allowances by EPA. At the same time, identification by itself does not ensure the favorable accounting treatment utilities may be seeking. Even with allowance identification provided by EPA, utilities seeking to gain more favorable tax or ratebase treatment would still have to link specified allowances with particular costs or transactions or compliance strategies.

In addition, assigning a unique number for each allowance would increase administrative complexity for both EPA and users of the Allowance Tracking System. Some additional administrative burdens would be placed on the authorized account representatives. Unless they accepted the default provisions proposed today, utilities would have to identify by serial number those allowances to be transferred, those to be deducted from the compliance subaccount for compliance purposes each year, and those to be deducted from the compliance subaccount to offset excess emissions, if any. Including a unique number for each allowance increases the possibility of errors in transfer requests, even if automated recordation systems are developed. This would add to the amount of time each authorized account representative would have to spend reviewing an allowance transfer request before submitting it to EPA, and verifying the transfer information after recordation by EPA in the tracking system. For these reasons, EPA is seeking public comment on the advisability of any serialization method.

EPA considered and rejected three other options for identifying allowances. The first option was to identify allowances only by the year in which they are first usable for compliance purposes. This would mean that all allowances for the same year would essentially be identical for compliance tracking purposes. This approach minimizes the administrative burdens for EPA and for the authorized account representatives. However, minimizing administrative burden would be of little relative benefit if uncertainty concerning accounting and tax treatment, in the absence of a detailed allowance identification scheme, inhibited allowance trading and resulted in unnecessarily high compliance costs. Because of the risk of inhibiting more efficient compliance strategies, this option was rejected.

The second option EPA considered and rejected was to identify allowances by the year in which they are first usable for compliance purposes and then to assign a number to each transfer. This transfer number would include the date of the transfer and the method under which the allowance was being acquired (e.g., auction, direct sale, reserve allocation,

bilateral transfer, etc.) for all the allowances involved in the transfer. EPA considered this option because a similar approach is used by both the New York Stock Exchange (NYSE) and the National Association of Securities Dealers Automated Quotations (NASDAQ) in reporting stock trades to the National Stock Clearing Corporation (NSCC). However, the identification number reported to NSCC is only used for NSCC purposes, and not for the use of the purchaser or seller of the stock.

EPA believes that this method might be useful from an accounting standpoint by offering some advantages of flexibility to the allowance holder in establishing inventory methods to record the acquisition and disposition of allowances without impairing the fungibility of allowances. The lot identification number can be used for tax and accounting purposes, connecting the date and price with the quantity of allowances purchased in a single transaction.

On the other hand, by recording each trade, including the identity of the transferror and transferee, and the amount of the allowances transferred (and the year in which they are first usable for compliance), EPA would already be capturing this information. This approach does not appear to add any value to the option of identifying allowances by the year in which they are first usable for compliance. In addition, assigning a number to each transfer could lead to some confusion, because each time the same allowances were transferred they would be assigned a new number.

The third option EPA considered and rejected was to assign a number identifying the unit for which each allowance was initially allocated or the reserve from which each allowance was initially allocated, in addition to a number denoting the year it could first be used for compliance purposes. Such identification might enable utilities to establish different cost records for allowances allocated or purchased, because those allowances would be distinguishable by the different numbers denoting their originating unit and compliance use date. Supplemented by a record of the dates of allowance transfers in the ATS, this approach would enable utilities to identify with specificity those allowances which they wanted to include in particular transactions or with which they wanted to associate certain costs. Furthermore, it would be easier for EPA to administer and, with less detailed specification of allowances to be transferred required, would result in lower probability of error in transfer requests and recordation by EPA. All of these benefits, and others already discussed, however, can be achieved by today's proposal.

EPA invites comment on the assignment of a unique identifying number to each allowance and on the other options considered. Comments are specifically requested on the benefits, such as favorable tax or ratebase treatment, that may be realized relative to the administrative disadvantages and higher transaction costs, and the extent to which those benefits are available through the options discussed.

5. Authorized Account Representative

(a) Certification and Function

The proposed rule requires the appointment of an authorized account representative for each account. The authorized account representative will be the only person authorized to carry out activities, such as allowance transfers, involving direct contact with EPA

concerning the Allowance Tracking System account.

In the case of an account for an affected unit, the authorized account representative must be the designated representative for the owners and operators of the unit, certified pursuant to §408(i) of the Act and proposed Part 72, Subpart B. Section 408(i) of the Act virtually mandates that in the case of affected units, the designated representative conduct transactions involving allowances. Therefore, the designated representative must function as the person with the sole authority to engage in transactions and other activities concerning the Allowance Tracking System account.

For non-unit accounts, the authorized account representative shall be the person designated in the New Account/New Authorized Account Representative Form submitted to EPA for opening the account. No allowance transfers for non-unit accounts will be recorded until the authorized account representative has signed a certificate of representation on the New Account/New Authorized Account Representative Form and EPA has approved the new account. The proposed certificate of representation for the non-unit authorized account representative would include: (i) a list of all persons with an ownership interest in the allowances held in the non-unit account; (ii) a statement that the representative was selected by an agreement binding on all persons with an ownership interest in the allowances held in the non-unit account; (iii) a statement that the authorized account representative has all necessary authority to carry out the duties and responsibilities of the authorized account representative; and (iv) a statement that the authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the agreement of representation. Where all ownership interest in the allowances rests with a single person, the certificate shall state that all allowances purchased by the person are deemed to be held for that person. EPA is proposing to allow the authorized account representative for a non-unit account (as with the designated representative) to designate one alternate authorized account representative in the event that the authorized account representative is absent or otherwise not available to perform actions or duties necessary at some point in time.

Authorized account representatives for non-unit accounts may be succeeded by any person who submits a New Account/New Authorized Account Representative Form and signs the certification of representation. The non-unit account authorized account representative will also be required to amend the list of persons with ownership interest whenever appropriate.

EPA is proposing these authorized account representative requirements for two basic reasons. First, EPA interprets §408(i) of the Act to impose such requirements in the case of unit accounts. Second, EPA believes that these requirements are essential to the efficient and reliable operation of the Allowance Tracking System and, by extension, to the market for whose activities it is the official record.

Section 408(i) provides in part: "No permit shall be issued under this section for a unit until the designated representative of the owners or operators has filed a certificate of representation with regard to matters under this title, including the holding and distribution of allowances and the proceeds of transactions involving allowances." Section 408(i) also requires the designated representative to file a certificate of representation concerning the holding and distribution of the unit's allowances between and among co-owners. To give effect to these provisions EPA believes that the designated representative must function as

the person with sole authority to engage in transactions and other activities concerning the Allowance Tracking System account.

Under the proposed requirements, EPA will be receiving information and instructions concerning transfers from only one person (or an alternate if one is specified in the certificate of representation) for each account. That person will be certified as the person authorized by the owners and operators of each unit, in the case of unit accounts, or by the owners of the allowances, in the case of non-unit accounts, to take action with respect to the allowance account. In addition, the owners and operators will have entered into an agreement governing the use and distribution of the allowances in the account. Finally, the authorized account representative will be certifying, in each submission to EPA, including allowance transfer submissions, that he or she is acting with full authority.

The effect of these three certifications -- certification of representation, certification of the fact of an agreement governing allowances and certification of authority to act -- is to establish a basis for EPA's reliance on transfers submitted by authorized account representatives for recordation in Allowance Tracking System accounts. Under this proposed scheme, EPA will be able to record any transfer submitted for recordation by the authorized account representatives for the accounts involved. The full legal effect of each recordation will be final as soon as recordation is made, without requiring EPA or the market to resort to secondary or additional confirmation of a transfer. This, in turn, will enhance EPA's ability to make final recordation of transfers quickly after they are submitted. Speedy final recordation will serve the interests of the parties to the transfer. Moreover, to the extent that the Allowance Tracking System will also function as a central source of public information as to allowance holdings, quick final recordation will assist all participants in the market. As applied to authorized account representatives for non-unit accounts, none of these certifications is required by the Act. The Agency is seeking specific comment on whether these requirements are necessary and whether they might impose undue burdens.

(b) Objections

The proposal specifies that objections concerning a certificate of representation, allowance transfer, or any other submission to EPA by the authorized account representative will have no effect on the recordation by EPA of an allowance transfer. That is, once an allowance transfer is recorded, the recordation will continue to have full effect, even if an objection is communicated to EPA subsequently. At the same time, EPA will continue to record transfers properly submitted and certified by an authorized account representative even after EPA becomes aware of an objection.

In addition, under today's proposal EPA will not adjudicate disputes between private parties concerning allowances or the actions of the authorized account representative. In Part 72, EPA is proposing the same provisions for the designated representative, who will be the authorized account representative for unit accounts.

These provisions are proposed for several reasons. EPA interprets §408(i) to require certain certifications and to authorize EPA to enforce such certifications. Clearly, EPA has authority under §113 of the Act to pursue appropriate sanctions in the event that an authorized account representative falsely certifies that he or she has been authorized to undertake an action. Thus, upon a demonstration of the falsity of a certification, EPA

would be in a position to pursue such sanctions. EPA believes that the threat of sanctions will greatly reduce the likelihood that authorized account representatives would submit false certifications or otherwise act against the rights of owners.

Similarly, owners injured by the actions of an authorized account representative taken in contravention of their ownership rights would be able to seek injunctive or monetary relief from the courts or to pursue other private dispute resolution procedures agreed to by the owners. Such relief would be available pursuant to the private commercial agreements and obligations between the owners and their representative, existence of which agreements must be certified pursuant to §408(i) of the Act and the proposed regulations in Part 72 and Part 73. Aggrieved owners would also be able to replace the authorized account representative. For these reasons, EPA has concluded that its authority under the Act, remedies available under commercial law governing the obligations between and among owners and their agents, and the ability of owners to appoint a successor authorized account representative, affords EPA and owners ample protection and recourse against wrongdoing by authorized account representatives.

At the same time, EPA believes that it would undermine the competitive and orderly functioning of the allowance market if the pendency of an objection, or even a determination that a certification with respect to a particular transaction was false, defeated the recordation of past or prospective allowance transfers (apart from an express judicial order mandating the reversal of a recordation or a bar on future recordation). First, EPA believes that third parties must be able to rely on the full effectiveness of the recordation of an allowance transfer. A rule that subjected transfers to the possibility that they might be canceled even after recordation would introduce uncertainties. These would impair the efficiency of the market by either inhibiting activity or imposing additional transaction costs incurred in an effort to provide against such uncertainties. Second, if the mere filing of an objection forced EPA to suspend recordation of transfers to or from an account, unwarranted objections could introduce disorder in the market or force authorized account representatives to make unreasonable concessions simply to satisfy objections however unwarranted. At the same time, for owners with legitimate grievances, suspending transfer activity would not enhance protection for co-owners appreciably beyond that already provided by the deterrent effect of civil remedies for protecting private commercial rights.

Finally, EPA does not believe that §408(i) extends EPA's authority to determine or enforce commercial obligations between and among owners. Even where the veracity of a certificate of representation depends on an interpretation of such obligations, EPA believes that it does not have the authority or competence, particularly in contrast to existing avenues for resolving commercial law disputes, to resolve such disputes. (See Part 72, Subpart B and preamble for further discussion of these issues.)

6. Account Contents

The proposed account contents in the Allowance Tracking System will provide the minimum information needed by the authorized account representatives and EPA to track compliance. First, EPA is proposing to list information about the authorized account

representative, including name, address, phone number, and telefacsimile number. This information is necessary for compliance purposes, because EPA must know to whom and where to submit communications concerning accounts. Authorized account representative information will help other authorized account representatives to make contact with potential trading partners or check the accuracy of other account information. Absent such information, allowance trading activity potentially could be hindered. In addition, if EPA did not establish and disseminate an official record of all authorized account representatives, unscrupulous or incompetent persons could misrepresent themselves to the market as account holders.

Second, EPA is proposing to include a list of all allowance transfers to or from the account, identifying transferror and transferee accounts and the quantity and identification of allowances transferred. This transfer information is useful for both the users and EPA to know what has occurred in the market, to help authorized account representatives verify accounts, and to help trace account recordation mistakes.

Third, the serial number of all allowances is necessary in order to confirm the proper allocation of allowances to the compliance subaccount, and to determine the compliance status for each unit. As stated earlier, allowances may not be used prior to the year for which they are allocated. Usable allowances will, therefore, be recorded in a unit's compliance subaccount, and these can be used to offset a unit's emissions in any year. Since EPA proposes to use serial numbers that reflect each allowance's compliance use date, listing the serial number simply makes it easier for EPA to use the subaccount system for implementing the Act's prohibition against the use of future year allowances for current year compliance.

Fourth, recording allowances in the future year subaccounts is necessary to track all recorded transfers throughout the proposed 30-year timespan. Again, these subaccounts allow for the segregation of allowances between the current year and future years as well as between each future year.

Finally, for unit accounts, EPA is proposing to include reports of the total tonnage of emissions for the calendar year as reported to date pursuant to the rules in Part 75. EPA may choose to include other information in the Allowance Tracking System should such information prove useful to the users of the system, and solicits comment on what information this might be.

7. Compliance

(a) Allowance transfer deadline

The Allowance Tracking System account will be used by EPA to determine compliance by a unit with its SO_2 emissions limitation requirements. Consistent with the requirements in §403(b) of the Act, EPA is proposing that no allowance can be used for the purposes of compliance with a unit's annual emissions limitation requirements for SO_2 unless, as of the allowance transfer deadline, such allowance is recorded in, or properly submitted for recordation in, the compliance subaccount for the unit. EPA is proposing that the allowance transfer deadline be January 30 of the calendar year following the year for which a unit's compliance is being determined.

(b) Purpose of an extended allowance recordation period

Including an allowance transfer period extending beyond the end of the calendar year appears to EPA to be consistent with the flexibility of the acid rain provisions. Although no such extended allowance recordation period is explicitly mentioned in the Act, and today's proposal does not alter the calendar year compliance requirements of the Act, the Statement of Managers included in the Conference Report for the Amendments states that "the conferees do not intend that any affected unit be subject to any penalty for 'exceeding' its allowances for a given year until that year has ended and all transfers of allowances... have been completed within a reasonable time period after the end of that year." [Conf. Rep. No. 952, 101st Cong., 2nd Sess., p. 343 1990] In addition, the added time to transfer allowances into a unit's account would not compromise the emissions reduction requirements of the acid rain program, because only those allowances useable for the calendar year during which the emissions occurred would be transferrable to the compliance subaccount for the year. Thus, as would be the case in the absence of an extended allowance transfer period, only those allowances allocated for use in the year for which each unit's compliance is being determined and those allowances banked from earlier years would be available to offset emissions at the unit in that year. The extended transfer period does not increase the aggregate balance of allowances available for use for purposes of compliance in any year.

The extended allowance transfer period is appropriate for several other reasons as well. The additional time after the end of a year for transferring allowances would allow affected units to avoid violations where allowances are otherwise readily available for purchase to offset emissions. The extended allowance transfer period would allow owners and operators of units to avoid violations resulting from unforeseen circumstances. In those instances where a unit must significantly increase its generation in the last few days of the calendar year, the extended allowance transfer period provides an opportunity to purchase allowances and avoid the penalty.

In addition, the extended transfer period would not dampen incentives for prudent behavior or amplify perverse incentives. Whether the allowance transfer deadline is December 31 or later, prudent owners will plan well enough in advance to avoid the need to purchase allowances during the potentially inflationary period just prior to the final date for effectuating transfers. Similarly, would-be sellers who may be hoarding allowances to exploit pre-deadline inflation are no less likely to do so in the face of an end-of-year transfer deadline as opposed to a later allowance transfer deadline.

(c) Power and allowance pools

For power and allowance pools, the allowance transfer deadline would enable units to implement arrangements where allowances could be transferred after the designated representatives fully collected and assessed the final emissions data for the year on a system-wide or pool basis. At that point, since compliance is determined on a unit-by-unit basis rather than an aggregate basis, surplus allowances from certain units could be transferred during the extended allowance transfer period to any units in the pool that needed them.

Some members of the public, pointing to §403(d)(2) of the Act, which refers to "pools," have suggested that EPA promulgate special provisions to accommodate utilities in power pools or those seeking to create allowance pools. For example, they argue, EPA

should permit pool-wide compliance with respect to total annual SO_2 emissions and allowances held for all units in such pools. EPA does not, however, interpret §403(d)(2) or §408(b) of the Act, which governs compliance plans and permits, to require or authorize such an approach. Furthermore, §403(g) of the Act specifically requires unit-by-unit compliance, and §411 of the Act imposes excess emissions penalties on the basis of unit compliance. This supports EPA's conclusion that compliance is to be based exclusively on unit-by-unit emissions and allowance holdings (with the exception of certain multi-unit compliance methods specifically provided for in the statute).

Even in the absence of special rules applicable to allowance pools, both the legislative history of Title IV and the Title's treatment of SO_2 emissions and allowances as completely fungible make it clear that allowance pools are expected to be created, and to operate, in the context of unit-by-unit compliance. The proposed January 30 allowance transfer deadline, together with utilities' capability, through continuous emissions monitoring, to estimate an individual unit's emissions during the year and to determine each unit's total annual emissions within hours of year-end, should provide power or allowance pools ample time to transfer allowances between and among units. The allowances could be held either in a non-unit account for the purposes of creating a pool or simply in unit accounts but subject to a pooling agreement. Allowances would be transferred between and among units (i.e., into the unit accounts) in amounts necessary to cover emissions from each unit. This approach, which relies simply on the mechanics of allowance transfers, appears to EPA to be more conducive to flexible pooling strategies than would an alternative pool-wide compliance approach. The latter would necessarily entail complex compliance planning and permitting requirements pursuant to §408 of the Act, possibly involving multiple permitting authorities.

(d) January 30

EPA is proposing that all allowance transfers must be submitted for recordation by January 30 of the calendar year following the calendar year for whose SO_2 emissions limitation requirements an allowance is to be applied.

In proposing the January 30 date, EPA concluded that this would provide units with ample time to transact and submit allowance transfers. At the same time, §411 of the Act and Part 77 of today's proposal require units with excess emissions to submit offset compliance plans by no later than 60 days after the end of the year in which they generated excess emissions. Accordingly, a January 30 allowance transfer deadline affords EPA one month in which to record closing transfers and to resolve any associated errors, and offers violating units one month from the submission of transfers to complete and submit excess emissions offset plans, if necessary, prior to the excess emissions offset planning deadline.

EPA expects that the vast majority of allowance transfers will occur before the end of the calendar year, since utilities customarily rely on forward planning. In fact, the spot market for allowances is likely to comprise only a small percentage of the total number of transfers. In addition, pursuant to proposed Part 75, utilities will be able to anticipate, and then to confirm, their total actual annual emissions well in advance of the January 30 deadline. Throughout the course of each year, continuous emissions monitoring, required under §412 of the Act and Part 75, will provide hourly emissions data. As a result, utilities will be able to project their total annual emissions throughout the course of the year. For

the same reason, units will be able to determine their actual annual emissions literally the day after year-end, January 1.

EPA believes it prudent to preserve a one-month period after final allowance transfers are to be submitted and before excess emissions offset compliance plans under Part 77 are due. During this month EPA will be required to record all properly submitted transfers to compliance subaccounts. If a large volume of transfers are submitted there may be a delay between submission and recordation for any given transfer. During that month, authorized account representatives will be required to determine the accuracy of any recordations and to submit error claims (as provided in proposed Subpart C) which EPA, in turn, will have to resolve. Again, final recordation in compliance subaccounts will have to be completed on a timely basis so that, where necessary, Part 77 excess emissions offset plans and excess emissions penalty payments can be submitted by the statutory 60-day deadline.

In most cases, utilities with units with excess emissions will know well in advance of the 60-day deadline of their need to pay penalties and prepare excess emissions offset plans, regardless of the allowance transfer deadline. Others, however, will be in non-compliance essentially as a result of their failure in last minute attempts to obtain allowances. For these units, allowing a month after the allowance transfer deadline to reckon their penalty liability and prepare offset plans is crucial.

EPA considered and rejected extending the allowance transfer deadline to February 15. Because continuous emission monitors will provide utilities with hourly emissions data, affected sources will be able to plan for and pursue allowance transfers beginning sometime before the end of the calendar year and certainly before the proposed January 30 deadline for recording allowances. In addition, a February 15 allowance transfer deadline would leave only 15 days before the deadline for submission of excess emissions penalties and offset plans required under Part 77. During that period, EPA would have to record transfers, notify the authorized account representatives as to whether the trades are approved or rejected, and, if necessary, process error claims. EPA would then have to make allowance deductions from compliance subaccounts to account for a unit's emissions for the year in order to determine compliance, and to identify those units with excess emissions. EPA does not believe that a 15-day period would offer sufficient time to carry out these functions reliably, particularly in Phase II of the program when the number of affected units will increase to over 2,000. Moreover, those units who failed at the last minute to secure sufficient allowances would not have sufficient time to prepare an excess emissions offset plan.

At the same time, EPA believes that the marginal advantages offered utilities by extending the allowance transfer period to 45 days instead of 30 are slight. EPA anticipates that the vast majority of compliance strategies, including allowance transfers, will be implemented on a long-term, multi-year basis. Few will involve short-term, end-of-year decisions to which an additional 15 days, beyond the initial 30 proposed today, would be critical. In addition, allowance "insurance" pools could be established on a long-term basis to accommodate end-of-year contingencies expeditiously and at low cost. To compete with such pools, spot market sales would likely also be driven down to a relatively low-cost.

EPA also considered a January 15 allowance transfer deadline. EPA is not proposing

this transfer cutoff date because confining end of year transfers to 15 days, as opposed to 30 days, would provide little, if any, enhancement of EPA's administrative efforts. Adding 15 days to the period between the allowance transfer deadline and the deadline for submission of emissions offset plans is also not critical, either to EPA's enforcement efforts or to units' development of excess emissions offset plans. Any units with substantial excess emissions would already be aware of their circumstances prior to the end of the calendar year, and could begin developing their offset plans well ahead of the deadline for submitting such plans, regardless of the date of the allowance transfer deadline. In addition, the time needed to consummate allowance transactions even if initiated well before year-end may warrant more than 15 additional days after year-end, thus justifying a longer extension.

Nevertheless, EPA requests specific comment on the advisability of a January 15 allowance transfer deadline. Because utilities will have the benefit of long- and medium-term compliance planning as well as nearly up-to-the-hour cumulative emissions data, they will have ample opportunity, well before the end of each calendar year, to determine their need for additional allowances and to acquire any such allowances. With the planned adoption by EPA of electronic methods for the submission of allowance transfers, transfers will be able to be submitted, received, and recorded in a minimal amount of time. These factors suggest a need for only a de minimis transfer deadline extension beyond the end of each calendar year. At the same time, compared to a January 30 deadline, a January 15 deadline accelerates the time within which (i) final transfers can be recorded; (ii) errors can be resolved; (iii) allowances can be deducted from compliance subaccounts for purposes of determining compliance; (iv) compliance subaccounts can be replenished with allowances from the pending future year subaccounts; and (v) transfer activity for what is now the current year can be recorded in the replenished compliance subaccount. These actions can only be completed consecutively and the sequence cannot begin until the allowance transfer deadline passes. It is in light of these considerations that EPA seeks comment on a January 15 allowance transfer deadline.

Finally, EPA considered a December 31 transfer deadline coinciding with the calendar year compliance requirements mandated by the Act. EPA is not proposing this deadline because it would not provide the additional flexibility of an extended allowance transfer period. Nonetheless, EPA requests specific comment on the advisability of a December 31 deadline. Such a deadline would provide more time for final transfers to be recorded and any errors resolved before offset plans and excess emissions penalties are due. In addition, deductions for compliance and replenishment of compliance subaccounts could occur earlier.

8. Deductions for Compliance

Once all recordations are made in compliance subaccounts, EPA is proposing to deduct from each unit's compliance subaccount allowances equal in amount to the unit's reported SO_2 emissions during the preceding calendar year. As already suggested in the previous discussion of the use of identifying numbers for allowances, EPA is sensitive to the potential importance, in promoting cost-saving market activity, of differential tax and ratebase treatment for particular allowances. Accordingly, EPA is proposing to permit the

authorized account representative for each unit to specify, by no later than the January 30 allowance transfer deadline, which allowances are to be deducted from the compliance subaccount. To the extent that units may be holding allowances with differing cost bases, this could enhance units' abilities to demonstrate what they believe to be their true compliance costs for tax and ratebase purposes.

In the event that an authorized account representative failed to specify particular allowances for deduction, the proposed default rule would operate on a "first-in, first-out" (FIFO) accounting basis. EPA would deduct first those allowances with the earliest compliance use date originally allocated for the unit and recorded in its compliance subaccount. Then, continuing with those with the earliest date of recordation, EPA would deduct any remaining allowances that were originally allocated for other units and subsequently recorded in the unit's compliance subaccount, until either no more allowances remained in the subaccount or total deductions equalled the unit's SO_2 emissions tonnage during the preceding year.

EPA is proposing the "first-in, first-out" or FIFO method for its default rule because EPA believes this approach to be most accommodating for the financial needs of utilities. The FIFO inventory accounting system is a common method used by industries for financial purposes of determining consumption of inventory, and it may reflect the preferable approach for tax purposes for affected units. If so, such a default rule would minimize the need for utilities to take affirmative steps in notifying EPA as to which allowances are to be deducted. Instead, the majority of utilities could rely on the default rule as offering the preferred method of deduction.

EPA also considered and rejected for its default rule the "last-in, first-out" or LIFO inventory accounting method. Under the LIFO method, EPA would begin its deduction of allowances with those most recently acquired, starting with those in the unit's compliance subaccount that had been allocated originally for other units and transferred to the unit's account. Then, continuing with those most recently allocated for the unit, EPA would deduct any remaining allowances until either no more allowances remained in the subaccount or total deductions equalled the unit's SO_2 emissions tonnage during the preceding year. Although LIFO is a widely used inventory accounting method, it did not appear to offer any significant financial or tax advantages to utilities and therefore would be less likely to be elected as a deduction method by affected units. Therefore, its selection by EPA as a default method would encourage utilities to notify EPA of the specific allowances in their compliance subaccounts they would prefer to be deducted for compliance purposes. Such notification would add to the compliance burden of the utilities, without offering any significant benefits to EPA on its own merits as a method of deduction.

EPA requests comment on the default methods for deducting allowances from compliance subaccounts and the advantages and disadvantages each method would offer to affected units.

9. Common Stacks

Where more than one unit's emissions are ducted through a single stack with a single emissions monitor, reported data will reflect the emissions of all units connected to the stack

without differentiating each unit's emissions. For this reason §75.11(a) and §72.50, also proposed today, provide that in those cases, EPA will require the units to submit a common stack plan and will aggregate the units' emissions and allowances for purposes of determining compliance. Accordingly, proposed Part 73 includes a parallel provision.

To conform to the unit-by-unit allocation provisions of the Act, EPA will allocate allowances and maintain separate accounts for each unit individually. Each year, to determine unit compliance, EPA will aggregate all allowances in the units' compliance subaccounts and then deduct from the aggregated total according to the same methods available under §73.35(b) to affected units with their own emissions stacks. EPA will accept Compliance Deduction Forms from a unit's authorized account representatives that specify the allowances to be deducted for compliance purposes for their units. When no allowances are specified, EPA will deduct allowances from the aggregated accounts in the "First-in, First-out" order, as described in §73.35(d), without regard to accounts of origin. Any allowances remaining after the deduction will be reallocated on a per capita basis. EPA has concluded that it is unnecessary to apply a more complex pro rata approach for reallocating remaining allowances, since utilities themselves can retransfer allowances between and among units after determining for themselves a more appropriate method of apportioning remaining allowances.

10. Deductions for Units Subject to Amended Phase I Substitution and Compensating Unit Plans

Proposed Part 72 authorizes amendments to Phase I Substitution plans and Compensating Unit plans to remove the designation of substitution or compensating units originally subject to such plans. Since allowances would be allocated for such units upon approval of the initial plan, proposed Part 72 requires the deduction from the units' accounts of allowances equivalent in number and compliance use date to those originally allocated for the units. Proposed Part 73 includes a parallel provision effecting such a deduction.

11. Deductions for Excess Emissions

Section 411(b) of the Act provides: "The Administrator shall also deduct allowances equal to the excess tonnage from those allocated for the source for the calendar year, or succeeding years during which offsets are required, following the year in which the excess emissions occurred." To meet this requirement, EPA is proposing that unless the designated representative has otherwise provided in an approved excess emissions offset plan, EPA will choose the order of the unit's allowances to be deducted. Following the "replenishment" of the unit's compliance subaccount with allowances from the future year subaccount corresponding to the year following the excess emissions, EPA will deduct from each such unit's compliance subaccount allowances in an amount equal to the unit's excess emissions.

By allowing the authorized account representative for a unit with excess emissions to include in its offset plan a specific designation of offset allowances, EPA is enabling the utility to determine the most cost-efficient way for it to come into compliance. An approved excess emissions offset plan may specify which allowances should be deducted and when

during the course of a year they should be deducted from the unit's account to offset its excess emissions. As is provided in Part 77, the offset plan may also specify that the allowances be deducted from a substitution unit's account. In the absence of such a plan, the unit with excess emissions must accept EPA's method of deducting allowances.

For those units governed by a common stack plan and monitored at a common stack and whose aggregated emissions exceed the aggregated number of allowances held by the units in their compliance subaccounts, EPA proposes a similar method of deducting excess emissions offset allowances as described for a single unit -that is, permitting the authorized account representative to identify specifically the allowances for deduction in the mandated offset plan. If no such identification is included in the source's plan, EPA would simply treat each unit's individual compliance subaccounts as a comprehensive compliance subaccount and their future subaccounts as comprehensive future subaccounts for the purposes of deducting offsetting allowances. Units monitored at a common stack are in any case deemed to be jointly and severally liable for excess emissions pursuant to §75.11 and §72.50. EPA thus would aggregate the units' subaccounts and deduct the appropriate number of allowances. Any allowances remaining in the aggregated subaccount would be reapportioned back to the units' individual subaccounts on a per capita basis. The utilities themselves could retransfer allowances between and among the units after determining for themselves an appropriate method of apportioning remaining allowances.

12. Banking

Section 403 of the Act requires that allowances not used for purposes of compliance be carried forward and added to allowances allocated for use in subsequent years. Following any deductions made for compliance purposes, EPA is proposing to retain in the compliance subaccount any allowances not deducted in offsetting the unit's SO_2 emissions. EPA believes this is the most simple and efficient way to identify unused allowances to be carried forward and added to allowances allocated for use in subsequent years. EPA sees no reason to require special procedures requiring further affirmative activity by the authorized account representative in order to effectuate banking.

13. Account Error and Dispute Resolution

EPA is proposing to allow an authorized account representative to notify EPA in writing in the event that he or she claims an error in the tracking system account. In order to prevent frivolous or unfounded claims, EPA would require all claims be made in writing, and include: (a) a description of the error; (b) a proposed correction of the error; (c) any supporting evidence of the error; and (d) certification by the authorized account representative. The submission of all claims in writing also establishes a record of such claims and the responses made, which should prevent additional disputes concerning inaccurate recall if suggested corrections, responses, or disputes are conveyed through a less permanent medium, such as oral conversation.

To limit unfounded claims further and to establish finality for compliance purposes,

the submission of all claims of error must be received by EPA within 20 business days, if the time period is marked from the date of submission of the transfer for recordation, or by no later than 10 business days, if the time period is marked by the date of EPA's transmission of the notice of recordation of the transfer. Furthermore, any claim of error concerning allowances in a compliance subaccount must be received by no later than 15 business days after the allowance transfer deadline for the compliance year in order to allow sufficient time for EPA to record those transfers submitted immediately before the allowance transfer deadline and for the authorized account representative to receive notification of the transfer and then to submit a claim of error. EPA is further proposing, however, to accept claim of errors submitted following these deadlines upon a showing by the authorized account representative of good cause for the delay.

Following receipt of any claim of error, EPA is proposing to respond in writing to the authorized account representative. Such response would include: (a) the determination made or action taken; and (b) reasons for such action. In order to avoid a drawn-out appeals process in the resolution of claims of error, EPA is proposing that all EPA decisions concerning a claim be within the Administrator's sole discretion. This will help to ensure the orderly functioning of the allowance system by quickly establishing finality and certainty. Furthermore, EPA recognizes that units will want to have their account balances reflect their official holding of allowances usable for compliance purposes in order for them to be able to specify the allowances EPA should deduct for compliance purposes and to continue with the unit's cost-minimizing compliance strategy. Designated representatives will also need to know with certainty if their units are in compliance with the SO_2 emissions limitation requirement to be able to submit an excess emissions offset plan to EPA for approval in a timely manner.

EPA is proposing that, following the authorized account representative's receipt of the Administrator's decision on the error claim submitted to EPA, the authorized account representative could, if desired, resubmit the claim and all relevant supporting documentation for reconsideration by the Administrator. EPA proposes each claim of error be restricted to one resubmission, in order to prevent burdensome or trivial error claim submission.

EPA requests comment on whether to afford an administrative appeals procedure for such claims as is provided in Part 72 for permit action appeals. In addition, EPA requests comment on whether to afford such appeals procedures in connection with other aspects of this Part.

14. Public Availability

EPA is proposing to make all information in the Allowance Tracking System accounts available to the public. Initially, EPA will make written records available. EPA is, however, developing a system of electronic access and will prescribe the appropriate methods of such access in the future, following public notice. EPA believes it is important to make account information publicly available for several reasons.

First, allowance market participants need to be provided with some basic market information. For example, the authorized account representative information will enable

market participants to make contact with potential trading partners or to check the accuracy of account information. Absent such information, allowance trading activity could be inhibited or involve higher transaction costs.

Second, the public, including special interest groups and researchers as well as private citizens, will have a strong interest in the environmental performance of the program. For example, they may want to see how much SO_2 units are emitting and the number of allowances units have in their accounts.

EPA will develop an electronic access system because electronic availability of information reduces the need for paperwork, reports, or submissions, and increases the speed with which information can be obtained. With an electronic system, authorized account representatives will be able to save time when they submit reports to EPA, and know much sooner when EPA has recorded an allowance transfer.

C. *Allowance Transfers*

1. Recordation of Transfers

Section 403 of the Act requires a transfer of an allowance to be certified by the parties to the transfer and received and recorded by the Administrator before it can be effective. Accordingly, as discussed above, EPA is proposing that no allowance may be used for purposes of a unit's compliance until the allowance is recorded or properly submitted for recordation. Of course, this must occur by the allowance transfer deadline for the allowance to be used for compliance in the current calendar year in the unit's account. However, it will be up to the parties to decide when to record a transfer, since EPA is not proposing any other requirements as to when or if a transfer must be submitted for recordation.

Some commenters believe that EPA should require that all transactions involving allowances, including options and other transactions involving the purchase of allowances in the future, be submitted for official recordation in the Allowance Tracking System (ATS). In addition, they believe that EPA should require that a notice of the transaction be submitted to EPA within a certain number of days of the transaction becoming legally binding between the parties for the transfer to be acceptable for official recordation in the ATS. They assert that the allowance market will not operate efficiently unless all transactions are recorded promptly in the ATS, which, they imply, may be the only readily available and affordable means of identifying transactions affecting ownership of allowances. Such complete and timely information is necessary, they argue, to assess supply and demand of allocated allowances, to determine what the market price might be, and to identify possible buyers or sellers of allowances. Such commenters believe that public display of every transaction may also be useful to identify possible hoarding activities which, they fear, may severely restrict the availability of allowances for compliance purposes.

EPA rejected this approach because it believes there is sufficient incentive for the private sector to develop systems to transact, record, and disseminate pertinent information on complex, strategic transactions in a timely manner without constraining parties' flexibility concerning transfers of allowances. In fact, the private sector is most likely better able than

EPA to record and disclose such transactions in a timely, proficient manner that would help maximize economically efficient decisions. Already, the Chicago Board of Trade and other exchanges have announced they are exploring establishing commercial exchanges for allowances and allowance-based financial instruments. Through such exchanges distilled price information and information on allowance trading would be broadly disseminated. Centralizing recordation of all transactions through EPA could impose higher, unnecessary costs on the market resulting from processing delays due to a greater volume and complexity of transactions to be recorded and slower notification of results. In addition, forcing such public disclosure of all allowance transactions may reveal sensitive business decisions about a firm's trading strategy that the firm may prefer be kept secret to maintain bargaining position in the market.

For these reasons, EPA is proposing to record only those transactions that effect the official transfer of an allowance at the time the transfer is submitted to EPA for recordation. Transactions that do not meet this requirement for direct and timely transfer of allowances, such as options and futures on the rights to allowances, would not be recorded in the ATS. If EPA required immediate recordation of private, commercial transactions involving allowances, EPA would not have the capability to enforce such a requirement. EPA would not be able to identify, or even to define, all private commercial transactions affecting allowances or pinpoint when they took place, limiting EPA's ability to enforce the requirement for timely recordation. Submittal of the transfer for recordation is not necessary for a commercial contract to be legally binding, and commercial transfers may occur without EPA's knowledge. Parties determined to postpone recordation might be able to structure transactions to circumvent the requirement, by avoiding the definition of "recordable" transfer. Apart from the condition that allowances must be recorded in a unit's account to be useable for compliance, EPA does not believe the Act contemplates that EPA penalize parties to a transfer for their failure to submit transfers to EPA for recordation. To refuse to record a transfer because it was "untimely" (again, apart from the allowance transfer deadline) would only undermine the purpose of the ATS as a credible record-keeping system of current holdings of allowances.

Even in the absence of a forced recordation requirement, the transferee has sufficient incentive to report the transfer promptly to EPA for official recordation to secure the allowances for compliance purposes. Timely recordation is important to the transferee simply to ensure that the allowances being transferred have not already been claimed by a subsequent transfer undertaken by the transferror. Furthermore, the transferee might also need such proof of holding in order to sell the allowances to another party.

2. Price and Other Terms of Transfers

Some commenters believe EPA should request and record the cash price paid and other terms of the contract (such as coal deliveries or power purchase arrangements) provided with each transfer of allowances. They argue that such information must be widely available to the market participants to determine whether the price offered for allowances is competitive, and to choose the most economically efficient compliance strategy. The growth of the allowance market, they argue, may be significantly hindered without

dissemination from a centralized repository, such as EPA, of information necessary for an affected unit to choose a compliance strategy. Although the private sector may have incentive to collect and disseminate such price information, the commenters believe it will be costly and limited in supply and scope. EPA, they argue, is in a unique position to collect and disseminate this information.

Although nothing in the Act prohibits EPA from collecting and reporting price and contract terms for allowance transfers, EPA proposes that the Agency not request and record the price and terms of an allowance transfer for several reasons. First, contract terms are likely to be complicated and tailored to the individual parties' needs, which would be difficult for EPA to record in a consistent, concise, and meaningful format. Second, any attempt by EPA or those participating in the transfers to calculate a numerical cash-equivalent price paid for an allowance incorporating other, non-cash terms would likely yield an imprecise result, and would not be useful or reliable for other market participants. At the same time, a single reported price paid for an allowance that did not contain the value of the other terms may also be misleading because any additional terms would most likely impact the actual price paid for the allowance.

More importantly, EPA believes that price and contract term information will be available through other public channels, along with other details about trading. Price information will be available from EPA auction results, while price and contract terms may be reported to the Federal Energy Regulatory Commission and State public utility commissions. Private markets will also supply useful price and quantity information through brokers and centralized information networks, as is done in financial and commodity markets. For example, the National Association of Security Dealers Automated Quotations System (NASDAQ) supplies timely price and volume information for the over-the-counter stock market, and multiple listing services provide location, amenities, and price information for regional real estate markets. Data resource companies also may collect the allowance transaction information, as exemplified by the variety of publicly displayed reportings of New York Stock Exchange and American Stock Exchange activities. Details on allowance trades would most likely be reported in trade newspapers and magazines.

Several commenters have suggested that some market participants would refuse to report the price and terms of allowance transfers to EPA, or delay the reporting of the transaction itself, because of the sensitivity of the information or its link to the competitiveness of their firms' operations. EPA does not have clear authority to refuse to record the transfer if the parties did not disclose the price or terms.

Even if EPA could compel the parties to disclose price and terms and honored their request that the information be held as confidential business information, EPA would not be able to guarantee its confidentiality. If challenged in court by outside parties under the terms of §114 of the Act or of the Freedom of Information Act (FOIA), EPA would be required to prove that the price and other terms of consideration associated with an allowance transfer are confidential trade secrets in order to prevent their release to the public. The outcome of such an argument is uncertain at this point, especially if such data is publicly reported to state Public Utility Commissions. Even publicly reporting this information in masked form through averaging reported prices or not publishing names at the party's request would not alleviate the risk of potential disclosure of all reported terms

under FOIA. EPA's general policy is to make publicly available all information it collects, unless such information is expressly prohibited from release by statute or EPA believes the withholding of such information is authorized under FOIA; EPA would have difficulty justifying a decision not to release information it has collected for the purpose of disseminating a distilled version of the same information.

Consequently, some commenters argue that EPA's inability to guarantee fully the confidentiality of information required for recordation of price and contract terms would discourage recordation of transfers with EPA, or even deter market participation. This concern does not appear to be well-founded in view of EPA's firm expectation that the market itself will foster information-gathering mechanisms, as will PUCs and FERC in carrying out their traditional regulatory duties.

Finally, many members of the public predict that utilities' tendency to use long-term forward contracts could give rise to a standardized, exchange-traded futures instrument. They argue that the fungibility of allowances, coupled with potential price volatility resulting from factors such as variations in energy demand over time, development of new technology and need for allowances by new units, render allowances very similar to other commodities for which such futures trading exists. If so, active futures exchanges could enhance the efficiency and liquidity of the allowance market by distilling a single uniform price for allowances. It is through mechanisms such as a futures exchange, therefore, that EPA believes the public would get critical information, which would be of superior value to any that EPA could collect by mandate. As discussed above, the already announced efforts of the Chicago Board of Trade and other exchanges could lead to an allowance-based financial exchange that would disseminate broadly distilled price information. EPA firmly believes that the mandatory, public collection of information concerning allowance-related transactions could inhibit the development of such exchanges, which typically rely on anonymity and a high volume of activity to succeed.

3. What Constitutes a Valid Transfer

EPA proposes to record only those transfers that meet the following criteria:

(a) the transfers are authorized and certified (in writing or by other authorized means) by the authorized account representatives for both the transferror account and the transferee account;

(b) each allowance cited in a request for transfer must be listed in the subaccount specified by the authorized account representative of the transferror account;

(c) the allowance requested for transfer was not allocated for the unit pursuant to the provisions of §72.44, for purposes of a repowering compliance plan, or pursuant to Part 74 (to be proposed and promulgated at a later date), and made available as a result of reduced utilization or shutdown at the unit;

(d) the allowance requested for transfer is recorded in the compliance subaccount or the current year subaccount and is to be transferred to another compliance subaccount or current year subaccount, or is recorded in a future year subaccount and is to be transferred to another future year subaccount for the same year; and

(e) the EPA Allowance Transfer Form submitted to EPA has been completed

properly.

EPA proposes to require this information to be submitted with each transfer because such information is necessary to maintain proper records for each account holder in the ATS. The submittal of the authorizing signatures of the authorized account representatives is necessary to verify that the transfer request is submitted with their full knowledge and permission.

A submitted transfer request that is incomplete will not be recorded and will be returned to the authorized account representative with notification of the reason that it was not recorded. If a transfer request lists some allowances, identified by their serial numbers, that are not actually in the account from which they were to be transferred, or are prohibited from transfer to another account (i.e., those allocated for the unit pursuant to §72.44(g) in connection with a repowering compliance plan, or those allocated pursuant to Part 74 and made available as a result of reduced utilization or shutdown at the unit), only those allowances listed in the request that are in the account and are not prohibited from transfer will be transferred and EPA will notify the authorized account representative of the reason that the transfer of the other allowances was not recorded.

If a transfer, such as that of all of a unit's allocations in perpetuity, includes allowances whose compliance use date is more than 30 years after the year in which the transfer is submitted, EPA will include in the relevant transfer accounts an instruction to record the transfer, as soon as the future subaccount "appears" in the ATS. As will be the case for transfers recorded as final in existing future year subaccounts immediately upon submission, the recordation-of-transfer instructions will be permanent and irrevocable. Only the submission of a new transfer request will effect any further transfer of those allowances. Directions for identifying such allowances by serial number will be provided through public notice at a future date.

4. Prohibited Transfers

(a) Transfers of Allowances Between Subaccounts of Different Years

Aside from emissions offsets by either allowances banked from previous years or certain allowance allocations authorized for 2000 through 2009, the Act prohibits emissions exceeding 8.95 million tons per year. Consequently, the Act also requires EPA to prohibit the use of any allowance prior to the calendar year for which the allowance was allocated [§403(g)]. EPA is effectuating this requirement in part by prohibiting transfers of allowances from a subaccount for a later year to a subaccount from an earlier year. Such a transfer would violate the annual emissions cap. If EPA permitted the use of a future allowance before its compliance use date, the cap on emissions would be violated by permitting emissions before they were authorized to occur, without their having been offset by an emissions reduction in a previous year.

The design of the subaccount system -- separating allowances into future year subaccounts based on each allowance's compliance use date -- prevents transferring an allowance from one future year subaccount to that for a later year. If that were to occur, the allowance would only be available for purposes of compliance in the later year corresponding to the year of the subaccount; it would no longer be available in the earlier

year of its compliance use date. In fact, allowance holders can accomplish the result of transferring allowances from one account's earlier year subaccount to another account's subaccount for a later year much more simply. After the allowance is transferred to the transferee's subaccount for the same year, the transferee can simply bank the allowance for use in a future year and do so while retaining the flexibility of using the allowance as early as its compliance use date.

(b) Transfers from Units with Excess Emissions

The Act specifies that it is unlawful for any affected unit to emit sulfur dioxide in excess of the number of allowances held for that unit for that year [§403(g)]. In addition, §411 of the Act and Part 77 require that EPA deduct allowances from those allocated for the unit for the year or years following the year in which the excess emissions occurred, in an amount equal to the unit's excess emissions. To ensure that it can implement this requirement, EPA proposes the following: for the account of an affected unit with excess emissions whose emissions offset plan has not yet been submitted and/or approved, EPA would prohibit the transfer of an amount of allowances in the unit's compliance subaccount needed to offset the excess emissions that occurred during the preceding year. Once the emissions offset plan is submitted and approved by EPA, the allowances subject to the prohibition may be transferred, if any remain after deductions are made for excess emissions.

By imposing a prohibition on transfers of a violating unit's allowances, EPA ensures its ability to meet the requirements of the Act directing it to deduct allowances for excess emissions. By limiting the prohibition only to those allowances necessary for compliance and not to the entire account balance, EPA maintains the unit account holder's flexibility in its trading activity. However, because there may be a period in each year during which the designated representative may be aware that a unit has excess emissions before the Agency does, a unit's authorized account representative will be violating §414 of the Act and Part 73 if he/she submits a transfer for recordation in violation of this prohibition, regardless of EPA's action in recording the transfer.

(c) Transfers involving allowances prohibited from transfer

The Act specifies that allowances allocated for a unit for an approved repowering compliance plan can not be transferred [§409(c)]. Allowances allocated to a non-affected source of SO_2 under the "opt-in" program requirements (to be promulgated later as Part 74) and made available as a result of reduced utilization or shutdown are also prohibited from transfer. EPA proposes to mark such restricted allowances in the Allowance Tracking System to ensure that EPA can determine whether any allowances included in a transfer request are subject to such restrictions.

5. Submission of Transfers

EPA proposes to require that the following information, at a minimum, be provided to EPA on an Allowance Transfer Form when authorized account representatives request EPA to transfer allowances between accounts:

(a) the numbers identifying both the transferror's and the transferee's accounts;

(b) specification of the compliance use date and serial number for each of the

allowances to be transferred;

(c) signatures of the authorized account representatives of both the transferror's and transferee's accounts, certifying the information submitted to record the transfer and that EPA's recordation of the transfer of allowances does not limit the affected unit's obligation to comply with annual emissions limitation requirements for any year; and

(d) where the transferee's account has not been established in the ATS, information required pursuant to the requirements in §73.31 for establishing a new account.

EPA believes that allowing the parties to a transaction to determine when to submit the Allowance Transfer Form to EPA to request recordation of a transfer, and consequently to determine when the transfer of allowances will be recorded, provides the greatest versatility and liquidity to the market. The form also serves as a legal record of the instructions for transfer, authorized by both parties, as indicated by their signatures.

The information requested on the Allowance Transfer Form is the minimum amount necessary for EPA to record the transfer. Specification of the compliance use date and serial number of each of the allowances requires the transferror to direct which allowances are to be transferred and from which subaccount, without which information EPA cannot record the requested transfer. Relevant account numbers and authorizing signatures ensure that the transfer is being conducted under full knowledge of the account owners, and that, notwithstanding EPA's action on the submitted transfer, the affected unit is still obligated to comply with its annual emissions limitation requirements.

EPA expects to record all submitted transfers that meet the requirements of the Act and Part 73. EPA will not review a unit's reported emissions for purposes of validating a transfer. The burden of responsibility for meeting compliance requirements is on the unit. Authorized account representatives would be required to certify acknowledgement of this responsibility when they submit transfers for recordation in order to underscore that EPA's recordation of the transfer will in no way be a basis for subsequent defenses to enforcement on the grounds that EPA's recording of a transfer nullified this obligation.

Today's proposal contemplates the use of electronic methods for submitting allowance transfers. EPA is evaluating various potential approaches to electronic transmission of allowance transfers, using either on-line access to the system (whereby the authorized account representatives would record the information directly into a system maintained by EPA) or Electronic Data Interchange (EDI - ANSI X12) standards for data exchange. EPA requests comment on these options. EPA will announce the selected alternative method(s) under Agency guidance provisions at a later time.

6. EPA Recordation of Transfers

EPA proposes to record an allowance transfer in the ATS following receipt of the Allowance Transfer Form, by deducting the allowance from the specified transferror's subaccount and adding it to the transferee's subaccount of the same year, provided that EPA has determined the transfer to be valid. Valid transfers would be recorded within five business days after receipt of the Allowance Transfer Form by EPA, except, as described below, during the time period immediately following the allowance transfer deadline. A maximum of five business days is a reasonable period of time for EPA to determine the

validity and completeness of the transfer instructions and provides sufficient certainty to the parties to the transfer upon which to plan compliance and subsequent allowance transactions. In any event, EPA will seek to minimize the time needed to record transfers.

In the period immediately following the allowance transfer deadline, however, transfers of allowances to and from compliance subaccounts will be recorded after EPA has recorded the requisite transfers and deductions for compliance purposes, listed in §73.34 and §73.35, to establish the correct balance of allowances in the replenished compliance subaccount. EPA considers this order of recordation of transfers affecting a unit's compliance subaccount to be necessary so that the compliance subaccount can be "closed" with respect to allowances applicable to emissions limitation requirements for the preceding year, and then replenished with banked and current year allowances.

7. Notification

EPA proposes to issue written notice, confirming the recordation of the transfer in the ATS, to the authorized account representatives of both the transferror's and transferee's accounts, within five business days following recordation. The notification would contain the account numbers of the transferror and transferee, the identifying numbers of the allowances transferred, and the date the transfer was recorded in the ATS. EPA would issue the notice in writing by United States mail, or other methods prescribed following public notice, within five business days of the transfer's recordation in the ATS. EPA believes that notification of the recordation of the transfer to the authorized account representatives is necessary to assure parties of the effectuation of the submitted transfer by means of its official recordation in the ATS.

8. Non-Recordation of Transfers

EPA proposes that transfers submitted to EPA that EPA determines to be invalid would not be recorded in the ATS. EPA believes that, because EPA's ATS is the official record of allowance transfers, EPA should not record transfers that do not meet the requirements of the official record-keeping system.

EPA proposes that when EPA receives an Allowance Transfer Form requesting recordation of the transfer in the ATS and determines the entire or a part of the transfer to be invalid, EPA would issue a notice of the non-recordation of the entire transfer or the invalid part of the transfer in the ATS to the authorized account representatives of both the transferror's and transferee's accounts within five business days following EPA's determination of the incomplete or invalid status of the transfer. The notification would contain the account numbers of the transferror and transferee, the identifying numbers of the allowances requested for transfer that were not transferred, and the reasons that the transfer for those allowances was not recorded. Upon rectifying the errors, the parties may then resubmit the transfer or its remaining unrecorded portions to EPA for recordation.

9. Electronic Reporting

EPA intends to design an electronic communication format that will allow authorized account representatives to submit their allowance transfer and allowance deduction notifications to EPA electronically and will provide immediate access to view Allowance Tracking System accounts. At the very least, this electronic communication would be available as an option for anyone wishing to use it. EPA requests comment on whether the Agency should mandate electronic reporting requirements for all Allowance Tracking System functions. The benefits of electronic reporting include speed and enhanced certainty. A potential drawback, however, is that such a mandate could create a barrier to participation in the allowance market and use of the ATS for a person without access to the technology, such as a personal computer and modem, that would be necessitated by an electronic format. If so, such a mandate could run afoul of the authorization in §403(b) of the Act for "any person" to transfer allowances and of the policy underlying the provision of promoting liquidity in the market.

D. Energy Conservation and Renewable Energy Reserve

1. Authority

Section 404(f) of the Act requires the Administrator to establish a Conservation and Renewable Energy Reserve (the "Reserve") of 300,000 allowances for distribution to electric utilities engaging in energy conservation or in renewable energy generation. The Reserve is to be created by deducting from total annual Phase II allocations 30,000 allowances per year in each of the first ten years of Phase II. Utilities may begin applying for allowances from the Reserve in 1993, one year following promulgation of the regulations, and may continue to apply until all 300,000 allowances have been allocated or until the year 2010 if any remain. The allowances will not be restricted by a compliance use date, but will be allocated for emissions avoided through the use of qualified renewable generation or as a result of qualified energy conservation measures initiated after January 1, 1992, and before the earlier of December 31, 2000 or the date on which any unit owned or operated by the electric utility becomes affected under Title IV of the Act.

The allowance allocation for applicants will be determined by a calculation specified in the Act that is based on a national "average" of emissions avoided through the use of a conservation measure or through generation from a renewable source of electricity. As the Act prescribes, EPA will promulgate regulations governing the operation of the Reserve by May of 1992, 18 months after enactment of the Amendments. The regulations creating the Reserve will be promulgated with the Phase II allocation regulations, no later than December 31, 1992.

2. Qualifying Criteria

The Act identifies a number of qualifying criteria which applicants must satisfy in order to be eligible for allowances from the Reserve, which EPA has interpreted in today's proposal.

(a) Least Cost Plan

One of the requirements for receiving allowances from the Reserve is that the applicant must have in place an energy conservation and electric power least cost plan for meeting future electric needs. The Act requires the least cost plan to include an evaluation of a full range of resources, including but not limited to new power supplies, energy conservation, and renewable energy resources, in order to meet expected future demand at lowest system cost. This provision in the Act will assist in assuring state regulatory authorities and consumers that the full range of options -- demand-side (i.e., use by electricity consumers) efficiency improvements as well as supply-side (i.e., generation by the utility) efficiency improvements -- are being considered to meet the electric power needs of ratepayers.

There are as many definitions of least cost planning as there are States that have adopted it. While the definitions and provisions vary, the elements common to such plans include:

(i) the utility must outline a plan for meeting future demand at the lowest system cost;

(ii) in so doing, the utility must consider explicitly both supply-side and demand-side resources; and

(iii) the utility must submit the plan to the regulatory commission (or ratemaking authority), if applicable for review and public comment.

The definition and applicable requirements of a least cost plan proposed today are consistent with the requirements outlined in the Act, but allow the States flexibility in implementing least cost planning criteria. The proposed definition identifies four key elements: (1) plan preparation; (2) public review; (3) regulatory oversight; and (4) implementation. As required by the Act, the state regulatory authority or entity with ratemaking authority over a utility shall certify in the application that the least cost planning requirements, as stated above, have been satisfied.

In addition, the proposed definition explicitly notes that consideration of social and environmental costs external to the utility's direct costs of resource investments (i.e., externalities) is acceptable, but not required. This is intended to allow for the full variety of State integrated least cost planning requirements, many of which include consideration of externalities. It is possible that the "lowest system cost" for these States differs from what it would otherwise be, absent any consideration of the social and environmental costs of resource decisions. Without this provision, the "lowest system cost" requirement might have the effect of denying eligibility to utilities in States that consider externalities in their least cost planning. Nothing in the Act or the legislative history suggests that the "lowest system cost" criterion be applied in a way that would discriminate against utilities in States that consider externalities. Accordingly, EPA believes that in the absence of a statutory mandate, such a discriminatory effect would defy congressional intent.

(b) Net Income Neutrality

The Act requires that utilities applying for allowances for conservation measures must have a rate structure that guarantees net income neutrality. Section 404(f)(2)(B)(iv) of the Act specifies that the net income of an electric utility after implementation of specific cost-effective energy conservation measures must be at least as high as such net income would have been if the energy conservation measures had not been implemented (i.e., that the

utility makes as much money on energy saved as energy sold). Accordingly, today's proposal includes this as a requirement for eligibility for an allocation of allowances from the Reserve.

Several general principles guided EPA while developing the proposed definition of net income neutrality as it pertains to utility conservation program implementation:

(i) to eliminate the disincentives to engage in conservation programs;

(ii) to create an incentive to engage in conservation; and

(iii) to allow flexibility of program implementation.

Historically, utilities have been discouraged from pursuing demand side energy efficiency improvements for a variety of reasons, including uncertain and untimely recovery of costs; lost rate-base revenues; absence of direct profit opportunities; potential increases in electricity rates; and institutional discomfort and unfamiliarity with conservation programs. Under standard practices, the more electricity a utility sells, the more revenue it makes. This poses a major disincentive for actions that would reduce sales, (i.e., conservation programs). Unless explicit mechanisms are included for full cost recovery of conservation expenditures, a disincentive for conservation will exist. If astutely adopted, full cost recovery can effectively eliminate this disincentive. A number of utilities and State regulatory authorities have worked together to create regulatory frameworks that eliminate these disincentives, and allow a utility to profit from conservation.

In addition, Representative Edward Markey of Massachusetts and Representative Carlos Moorhead of California, the authors of the provision (added by an amendment in the House Committee on Energy and Commerce) stated, "We believe that utilities must be allowed to profit from conservation so that they will aggressively pursue all cost-effective means of improving their customers' energy efficiency" [House Report No. 490, 101st Cong., 2nd sess., Part 1, at 675 (1990)]. Section 404(f)(2)(B)(iv) of the Act establishes a net income neutrality provision as a prerequisite for an allocation of allowances from the Reserve that is intended both to encourage the development of ratemaking frameworks that put conservation on an equal footing with energy generation and to create incentives for conservation.

The creation of an incentive to pursue demand-side programs can occur in a variety of ways which may include explicitly linking profits to conservation savings. In January 1991, such profit-enhancing programs existed in six states (California, Massachusetts, Nevada, New Hampshire, New York, and Rhode Island); by April 1991 a number of others had joined the ranks and several more are expected to follow in the near future.

The definition of net income neutrality (§73.3) proposed today allows States flexibility in establishing rate-making methods or procedures that could be used to satisfy the net income neutrality requirement. For example, commenters have pointed out that requiring strict decoupling of profits from sales may not be necessary if the benefits of cost-effective conservation measures are split between ratepayers and stockholders. The economic incentives instituted as part of shared-savings conservation programs may be enough to encourage utility implementation of conservation programs. Accordingly, the Agency is not proposing a single method -- such as compensating for net income lost on a foregone investment in electricity supply -- for establishing net income neutrality.

(c) Certification of net income neutrality by the Secretary of Energy

Section 404(f)(2)(B)(iv) of the Act requires that the Secretary of the Department of Energy (DOE) certify that the State regulatory authority with jurisdiction over a utility's rates and charges has implemented provisions that guarantee net income neutrality. This requirement applies only when the utility is seeking to qualify for allowances on the basis of its implementation of conservation measures. EPA is proposing that applicants apply separately to DOE for net income neutrality certification using Supplement A of the application. EPA will conditionally approve applications pending certification by DOE.

EPA considered, but rejected, sending each application that was the first for each State to DOE to certify that the State had implemented net income neutrality. Once a State had been certified by DOE that it had established net income neutrality in its rate-making, all subsequent applications from utilities from that State would be deemed to have met the requirement of the Act and be eligible for allowances from the Reserve. However, EPA is proposing to reject this option because States sometimes establish different ratemaking structures for different utilities. As a result, each utility's ratemaking structure may be different, requiring separate certification. Because the requirement of net income neutrality is so integral to the success of the Reserve program, and the number of allowances in the Reserve may be scarce in relation to demand, EPA believes it must have certainty that this requirement is being met for each applicant. However, after a utility has received initial certification of net income neutrality, it may reapply, certifying that the same rate structure still applies without needing to go through another full review.

(d) Qualified energy conservation measures

As part of the regulations governing the Conservation and Renewable Energy Reserve, the Act requires EPA to identify and list "qualified energy conservation measures" [§404(f)(1)(A) and (f)(4)]. In addition to establishing such a list, EPA proposes to set forth criteria for identifying additional qualifying energy conservation measures for purposes of the Reserve. The proposed criteria, set forth in §73.81(a), are consistent with the legislative language. With demand-side programs still in the relatively early stage of development, much opportunity for innovation remains for conservation program design and implementation. From a pollution prevention standpoint, EPA believes it consistent with the Act to foster this innovation. A mere list of already existing "qualified conservation measures" would eliminate opportunities for innovators.

Accordingly, the actual list of qualified conservation measures, which appears in Appendix B of Part 73, Subpart F, is illustrative rather than comprehensive and exclusive. The list was assembled based on extensive comment from utility, regulatory, and industry representatives and includes only those measures currently in use throughout the United States.

EPA proposes that measures not on the list be approved by the State regulatory authority that regulates the rates of the applicant or by the Administrator if the applicant is an electric utility whose rates are not regulated by a State regulatory authority. EPA believes that a State regulatory authority is the appropriate entity to review and approve a conservation measure not listed in Appendix B(1) because of such authority's ability to access the cost-effectiveness of the measure. State authorities routinely make such reviews in connection with the review of least cost plans and other review of measures undertaken by utilities. EPA is also proposing the same procedure for renewable energy generation not

listed in Appendix B(1) for the same reasons stated above.

EPA invites public comment on the potential need and mechanisms for updating the list, as well as on the provisions of proposed §73.81 for doing so.

EPA is proposing not to include supply-side efficiency improvements in the list of qualified conservation measures. EPA bases this proposal on several factors. The Act's emphasis on net income neutrality reflects an intent to address the potential losses in utility income associated with demand-side conservation measures, thus suggesting congressional focus on demand-side efficiencies. Since, in contrast to the case of supply-side technologies, disincentives associated with rate-making and with other economic factors have been inhibiting aggressive pursuit of cost-effective demand-side programs since the 1970s, it would only be logical for an incentive program of this nature to confine itself to demand-side efficiency. In addition, EPA projects that a program that authorizes distribution of the Reserve to supply-side as well as demand-side programs may risk depleting the Reserve after approval of only a very few applications. In that case, the program would be of benefit to only a few utilities, defeating its implicit purpose of promoting demand-side management and the adoption of income-neutral ratemaking on a widespread basis.

(e) Qualified renewable energy generation

Section 404(f)(1)(B) and §404(f)(4) of the Act require EPA to identify and list "qualified renewable energy." The Act defines "qualified renewable energy" as electricity generation derived from biomass, solar, geothermal, or wind resources. The definition that EPA is proposing [§73.3 of the regulations] simply elaborates on this statutory definition.

The Act provides general criteria concerning the technologies qualifying for allowances from the Reserve. Based on these criteria, the proposal lists qualifying renewable energy sources in Appendix B of Part 73, Subpart F. The list does not include renewable energy sources that generate electricity indirectly. As in the case of qualifying energy conservation measures, EPA also proposes to allow the qualified renewable energy generation list to be expanded by developing technologies.

In connection with the listed technologies, further elaboration in at least two areas is necessary: (i) the treatment of renewable/fossil hybrid generation; and (ii) appropriate categories of biomass.

(i) Renewable/fossil hybrids

Some renewable energy technologies function well in concert with conventional fossil fuel. The most notable example is the Luz solar thermal design, which uses natural gas to maintain steam temperatures and pressures in cases of intermittent cloud cover or early morning/late afternoon reductions in solar insolation during some months of the year. Deployment of other hybrid technologies, including biomass/coal co-firing and wind/combustion turbine combinations, is likely in the near future.

The Act does not provide specific guidance on how the EPA should treat generation from these hybrid technologies in terms of calculating allowances. EPA decided that allowance calculations should be based on renewable resource heat input. In practice this means, for example, that a solar thermal electric facility using the sun for 75% of its generation in a calendar year would receive allowances based on 75% of its total generation. This option also permits a coal plant using 20% biomass in its boiler to receive allowances

for 20% of the generation from that plant.

The benefits of this option are that it reflects actual reliance on renewable resources and associated emissions reductions, thus reducing the risks of an over-allocation, or spurious allocation, of potentially scarce allowances in the Reserve to any one applicant. At the same time, it provides an incentive to maximize use of renewable resources vis a vis fossil resources. Although this option requires EPA to collect more detailed information on annual plant operations [§73.82(a)(9) of the regulations], it is unlikely to pose a problem, either technically or administratively.

(ii) Appropriate biomass categories

Biomass, as defined by the Public Utility Regulatory Policies Act of 1978 would include (1) wood and wood waste; (2) herbaceous crops and agricultural waste; (3) landfill gas; and (4) municipal solid waste (MSW). EPA proposes to allow (1), (2), (3), and (4) be considered as biomass resources for purposes of the Reserve.

(f) Ownership criteria

Section 404(f)(2)(B)(v) of the Act requires that recipients of allowances from the Reserve must own or operate at least one affected unit. EPA is proposing that partial ownership or cooperative operation agreements pursuant to the guidelines set forth under "life-of-the-unit, firm power contractual arrangement(s)," as defined in §402(27) of the Act, meet the eligibility requirements. EPA proposes to require that the applicant list the name and Allowance Tracking System number of at least one affected unit for which the applicant is listed as an owner or operator.

(g) Demonstration that requirements have been met

Section 404(f)(2)(D) of the Act requires that each applicant demonstrate that:

(i) it is paying in whole or in part for the energy conservation measures deployed or the renewable energy generated;

(ii) avoided emissions are quantified in accordance with the regulations promulgated under §404(f) of the Act;

(iii) it has implemented a least cost plan;

(iv) the qualified energy conservation measures or renewable energy in question are consistent with the least cost plan;

(v) the least cost plan has been approved by the State regulatory authority or another entity with rate-making authority;

(vi) in the case of conservation measures, the state rate-making authority has established rates that ensure net income neutrality as certified by DOE; and

(vii) it owns or operates at least one affected unit.

EPA proposes several additional requirement for qualifying applications. First, EPA proposes to require the applicant to state and certify the amount of money spent on conservation or renewable energy generation. This information is being required simply to substantiate that the utility has met the statutory payment requirement. Second, quantification of avoided emissions will be determined by the following calculations, as prescribed in §404(f)(2)(E) of the Act:

For Conservation: [(kWh saved) * (.004) divided by (2000)]

For Renewable Energy:

[(kWh generated) * (.004) divided by (2000)]

Where .004 = (.4 lbs/mmBtu) x (10,000 Btu/kWh)
and 2000 lbs = 1 ton = 1 allowance

These calculations reflect a hypothetical coal plant that emits .4 pounds of sulfur dioxide per million Btu of coal burned. Based on these calculations, the 300,000 Conservation and Renewable Energy Reserve allowances will be allocated to reflect 150,000 million kWh of "saved" or renewable energy generation.

For the least cost plan requirement, EPA proposes that the State regulatory authority or entity with rate-making authority certify that the applicant has, and is implementing, a least cost plan. EPA believes a certification is sufficient demonstration because least cost plans undergo public review and comment.

3. Application Procedures

The Conservation and Renewable Energy Reserve is structured to encourage utilities and their regulators to move forward with least-cost planning and regulatory reform. Such actions will not only facilitate compliance with the Act, but could be critical elements in economically and environmentally sound utility long-term planning [House Report No. 490, 101st Cong., 2nd sess., at 675 (1990)].

Although the Act does not prescribe procedures for allocating allowances from the Reserve or for implementing the program, today's proposal includes specific provisions governing the allocation of the allowances, first-come, first-served rules, procedures for verifying conservation program effectiveness and renewable energy generation, and certification of the application.

(a) Application and allocation

There are a variety of options for distributing allowances from the Reserve within the guidelines specified in the Act. Options considered by EPA include:

(i) reserving allowances for later allocation based on planned conservation and/or renewable energy generation;

(ii) allocating allowances based on planned conservation and/or renewable energy generation; and

(iii) allocating allowances only after demonstration of achieved conservation and/or renewable energy generation.

EPA is proposing that allowances be awarded annually based on installed measures or renewable generation that occurred during the previous calendar year. Verification is to be provided at the time of application, and applications are to be submitted after measures have been installed and verification has been made. EPA decided that reserving or allocating allowances based on planned conservation measures or renewable energy generation would jeopardize the integrity of the Reserve. Though these methods provide some certainty of allowance availability for utilities planning to implement conservation measures or invest in renewable energy generation, they make the Reserve vulnerable to the possibility of miscalculated avoided emissions or conservation measures or renewable energy projects never being implemented. As a result, the "true" number of allowances in the Reserve would not be certain, which could discourage participation in this program. Allocation of allowances after energy savings have been verified is simple and direct, and

will encourage early and aggressive action by utilities to implement conservation measures or utilize renewable energy.

EPA is proposing that applications be submitted to the Administrator beginning on January 1, 1993, which is one year following the beginning of the period of applicability. Commenters have suggested that EPA delay this date by a few months to allow time for more accurate verification of conservation savings. They argue that since the allowances from the Reserve are allocated on a first-come, first-served basis, there will be pressure to send in applications to the Administrator before complete and accurate verification of conservation savings can be fully assured. EPA believes, however, that the likelihood that the Administrator would reject deficient applications should minimize this problem. EPA requests specific comments on the annual date on which applications for the Reserve may be submitted.

The burden of expediting the verification process, described below, will be on the applicant utility. This means that applications for allowances from the Reserve may be submitted annually or less frequently for a number of years for retrospective energy savings. Allowances will not be distributed for savings to be realized in future years, even for measures already installed.

EPA examination of currently "eligible" utilities -- that is, those with active conservation programs and/or renewable generation, least cost plans, and net income neutrality for conservation measures -- indicates that if allowances are allocated annually on a retrospective basis the depletion of the Reserve is unlikely until at least a few years into the program. Thus, the recommended option extends the incentive effects of the program by allowing several years during which other utilities may initiate conservation and renewable energy programs. In addition, under the proposal, application and verification will occur at the same time, thus eliminating the risk that EPA will be forced to reallocate already-allocated allowances whenever verification reveals that previously approved programs have not been implemented successfully.

Commenters have indicated that these proposed procedures might preclude de facto any allowances from being awarded to renewable energy generation, since longer periods of time elapse between planning and deployment of new renewable energy capacity. To prevent this outcome, EPA is proposing that the Administrator review the allocations from the Reserve when 240,000 allowances have been allocated. If at that time either renewable energy generation or conservation projects appear to be in a position of receiving fewer than 60,000 allowances before the Reserve is depleted, an amount equal to 60,000 allowances less any allowances already allocated for either renewable energy or conservation will be placed in a subaccount in the Reserve and allocated only for conservation or renewable energy projects, depending on which type has not yet received 60,000 allowances.

The proposed 60,000 allowance subaccount for renewable energy is consistent with the CAAA legislative history that tried to encourage development of renewable energy projects. The Senate version of the Amendments included a provision for a Renewable Energy Reserve, not dissimilar from the renewable energy component of the program ultimately incorporated in the Act. Specific rationale for a renewable energy program was provided by Senator Wyche Fowler during the Senate debate on the Amendments.

...As we deliberate on how to get the cleanest air in the most cost-effective

manner, we must not overlook the potential of conservation and renewable energy technologies that are inherently clean. Renewable energy sources such as solar, wind, and geothermal are emissions free. This amendment will bring these and other renewable sources on line to lay a foundation for better air quality...

[Senator Wyche Fowler, Congressional Record - Senate, S 3777, April 3, 1990.]

EPA determined that 60,000 allowances was an appropriate number to "guarantee" for renewable energy generation. EPA examined the potential for different renewable resources to be on-line during the eight years of Reserve operation and concluded that a 60,000-allowance "floor" would be adequate to assure "later-starting" renewable energy projects participation in the Reserve program.

Finally, EPA proposes to limit the total number of allowances that may be allocated in connection with any one of the four categories of renewable resources -- biomass, solar, geothermal, and wind -- to no more than 10% of the Reserve, or 30,000 allowances. This reflects EPA's concern that biomass, which, in the aggregate, represents more than 90% of the combustible MSW stream, could absorb a disproportionate share of the Reserve.

EPA estimates that waste-to-energy generation alone could consume in excess of 100,000 allowances from the Reserve. The number and geographical diversity of waste-to-energy facilities in operation, or commissioned to operate in the near future, suggests that, relative to other sources of renewable energy generation, MSW is a renewable resource already being substantially exploited. The widespread and growing utilization of these facilities appears to reflect strict regulation, under the Resource Conservation and Recovery Act, of sanitary landfills, which, in turn, favors the MSW-incineration alternative. In addition, waste-to-energy facilities, by definition, provide a major function -- waste disposal -- beyond the production of energy that other renewable energy resources do not. In view of the incentive-creating function of the Reserve, EPA concluded that it would be inappropriate to devote up to one-third of the Reserve to a technology already in widespread and increasing use.

At the same time, however, a significant component of the combustible MSW stream is biomass. Accordingly, EPA does not believe a complete exclusion of these resources to be justifiable, particularly in view of the proposed limit on allocations for electrical generation from any one category.

The 30,000-allowance limit in conjunction with the 60,000-allowance minimum discussed above, ensures that at least 30,000 allowances will be available for renewable resources currently utilized less than MSW in waste-to-energy facilities.

(b) First-come, first-served

To implement the Act's requirement that allowances be allocated on a "first-come, first-served basis," EPA proposes to determine the order in which applications are received by their date and time stamp. EPA believes that all applications to this program will not be submitted concurrently. Instead they are likely to be submitted gradually as applications are completed. As a result, a more complicated queuing system is unnecessary.

EPA proposes to conditionally approve applications and designate allowances from

the Reserve pending DOE certification of net income neutrality. Final approval will be granted upon notification of certification by DOE. In the event that the number of allowances remaining is smaller than the amount for which a qualifying applicant has applied, the applicant will receive the number of allowances remaining in the Reserve.

For the certification of net income neutrality by DOE, the Secretary of DOE will also process and certify Supplement A of the application according to the order, by date and time, in which it is received from either the applicant, or by the Administrator in the case of Supplement A submitted to the EPA and then forwarded to the Secretary.

(c) Verification

The Act requires the utility to quantify its estimates of avoided emissions according to regulations promulgated by the Administrator [§404(f)(2)(B)(ii)]. Given the complexity and multitude of verification methods in quantification of energy conservation savings and the degree to which State regulators are, and will continue to be, involved in conservation program evaluation, the guidelines must be flexible enough to allow State innovation, but rigorous enough to provide EPA with the tools necessary to ensure that the Reserve is allocated appropriately, particularly in cases of non-State-regulated utilities in which verification responsibility falls directly to EPA.

Quantifying emissions avoided from renewable energy generation is not nearly as difficult as verifying conservation savings, given the formula specified in the Act (Kwh * .004 divided by 2000). Utility record-keeping will provide EPA with the necessary renewable generation figures to verify that avoided emissions are calculated correctly.

(i) State/Utility Experience with Estimating Conservation Savings

During the past decade a number of utilities have gained experience in demand side program implementation. Nonetheless, evaluation of program effectiveness remains imprecise. Because many factors affect energy consumption -- weather, economic conditions, household size and age of occupants, age of appliances, etc. -- it is difficult to isolate energy saved as a result of conservation efforts.

(ii) Recommended guidelines

In view of State experience of conservation program evaluation, EPA proposes to defer to State regulators for conservation verification in cases where the State has regulatory oversight. Regulatory scrutiny in these cases is likely to be fairly rigorous as necessitated by net income neutrality ratemaking structures, which are also required for qualification. In cases of non-State-regulated utilities, EPA will require the use of its conservation verification protocol (described below), which will be published at a later date.

(iii) EPA conservation verification protocol

The EPA Conservation Verification Protocol will likely include, standard methodologies and procedures for use by applying utilities and/or their independent contractors in developing estimates of energy saved as a result of implemented conservation programs. The Protocol is currently under development and will be published for public comment under a separate Federal Register notification.

(d) Application submittal

Applications for allowances from the Reserve must be signed by a "certifying official" (as defined in §73.3 of the regulations) of the utility. Subject to application approval and allowance availability, the utility will be allocated allowances from the Reserve. If the utility

does not have an account in the Allowance Tracking System, the utility must complete and send to EPA a New Account/New Authorized Account Representative Form either with the Reserve Application or after the application has been approved. The application may, but is not required to, be submitted by a "designated representative" as specified in Subpart B of Part 72, because the Reserve allowances are being allocated to utility systems for conservation or renewable energy and not to individual units. However, the recipient of the Reserve allowances may transfer the allowances to a unit account if he or she desires.

(e) Certification

All applications must be certified by the certifying official as to the truth and correctness of the information submitted to EPA. The Act requires that utilities regulated by State regulatory authorities must submit their applications to their State regulatory authority for review of accuracy and compliance with the requirements of the Act and the regulations as proposed herein. EPA proposes to require, in the application, a signed certification by a State regulatory authority that this review was completed.

VI. Continuous Emission Monitoring Regulation

A. Rule Background and Summary

1. Applicability

Pursuant to Section 412 of the Clean Air Act Amendments of 1990 (the Act), proposed Part 75 of the Acid Rain program applies to existing affected units, to each unit that elects to become an affected unit, and to each new utility unit upon commencement of its operation. Emission monitoring equipment required by the proposed rule would be installed, operational, and certified by November 15, 1993, for Phase I affected units; by January 1, 1995, for existing Phase II affected units; and upon commencement of operation for new units. An affected unit that formally commits to retirement before December 31, 1994, would be exempt from the requirements of the proposed rule.

2. Purpose of the Continuous Emission Monitoring Program

Continuous emission monitoring systems (CEMS) are indispensable to the successful implementation of the Acid Rain program because of two unique characteristics that distinguish this program from traditional emission limitation programs. First, the compliance flexibility provided by the allowance trading provisions of the sulfur dioxide (SO_2) control program mandates complete and accurate reporting of emissions data by the affected units. Second, the Act expresses the program's emission goals in terms of absolute tons of SO_2 and nitrogen oxides (NO_x). (Traditionally, such goals have been expressed in terms of pollutant mass emission rates relative to the heat input of the fuel which, for utilities, have been in pounds of pollutant per million British thermal units (lbs/mmBtu).)

The CEMS program proposed in today's rule is essential to the proper functioning of the allowance trading provisions of the Acid Rain program because the Act uses the newly created "commodities" of allowances as proxies for emissions in the trading. As noted previously, allowances may be freely bought and sold, and EPA will compare each unit's allowances held against the unit's SO_2 emissions reported for each year. Therefore, if continuous emission monitoring fails to provide an accurate, timely, impartial, and comprehensive estimate of SO_2 emissions, the value of allowances will be unstable and uncertain, and the confidence of market participants in the trading program will be undermined.

EPA's review of other markets, including environmental emission trading markets, reinforces this conclusion. The U.S. General Accounting Office's 1986 Study of EPA's regulations for Lead Rights Banking noted that the self-reported, but unverified and uncertified, data on lead emissions from refineries produced numerous inaccuracies, which resulted in possible overstatements of both the emission reductions and the number of lead rights that

were created.[1] A similar outcome for the Acid Rain program would frustrate the emission reduction goals of the Act and undermine the value of emission control investments.

Numerous other markets reviewed by the Agency, including various stock markets, futures exchanges, and commodity markets, illustrate that there is a fundamental, essential feature to smoothly operating markets: a method for certifying the existence and quantity of the commodity to be traded.[2] Most often, certification of the commodities are made by independent institutions whose integrity and reputation are such that their certification is trusted. The CEMS program proposed today incorporates that feature by requiring the regular reporting of emission data certified to be accurate. Additionally, regular verification and certification of the accuracy of the CEMS data by sources is reinforced by EPA's independent audit authority.

Title IV of the Act makes clear that its purpose is to "reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide of ten million tons from 1980 emission levels, and, in combination with other provisions of this Act, of nitrogen oxides emissions of approximately two million tons from 1980 emission levels...." [Section 401(b)]. In addition, Section 403(a)(1) requires that in Phase II of the program the Administrator "shall not allocate annual allowances to emit sulfur dioxide pursuant to Section 405 in such an amount as would result in total annual emissions of sulfur dioxide from utility units in excess of 8.90 million tons...." EPA believes that a comprehensive monitoring program, as mandated in Section 412 of the Act, is fundamental to ensuring that the acid deposition precursor emission reduction goals of the Act are, in fact, achieved.

3. Statutory Authority

The primary statutory authority for the regulations proposed in Part 75 is contained in Section 412 of the Act, which requires the installation and operation of a continuous emission monitoring system (CEMS) on each affected unit and the quality assurance of data for SO_2, NO_x, opacity, and volumetric flow. In addition, Section 821 of the Act requires all affected units in the Acid Rain program to monitor carbon dioxide (CO_2) emissions.

Section 402(7) of Title IV of the Act defines a CEMS as "...the equipment as required by Section 412, used to sample, analyze, measure, and provide on a continuous basis a permanent

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[1]Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, "Vehicle Emissions: EPA Program to Assist Leaded-Gasoline Producers Needs Prompt Improvement," GAO/RCED-86-182.

[2]"Fostering a Spot Market for Allowances: Institutional Parallels in Other Markets," A. McGartland, draft discussion paper prepared for U.S. EPA, 1991.

record of emissions and flow (expressed in pounds per million British thermal units (lbs/mmBtu), pounds per hour (lbs/hr) or such other form as the Administrator may prescribe by regulations under Section 412)".

Section 412(d) requires that if data from the CEMS or from an alternative monitoring system approved by the Administrator (equivalent to a CEMS) are not available for a unit during any period of a calendar year and, as provided in Section 412(d), "the owner or operator cannot provide information, satisfactory to the Administrator, on emissions during that period, the Administrator shall deem the unit to be operating in an uncontrolled manner...." The subsection also requires EPA to prescribe a means in the Acid Rain CEMS regulations for calculating emissions during missing data periods.

In accordance with Section 412(a), EPA must promulgate the specifications and quality assurance requirements for CEMS, recordkeeping and reporting requirements, and criteria for approval of alternative monitoring systems not later than eighteen months after enactment (i.e., by May 15, 1992). An alternative system must be "demonstrated as providing information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS....Such regulations may include limitations on the use of alternative compliance methods by units equipped with an alternative monitoring system as may be necessary to preserve the orderly functioning of the allowance system, and which will ensure the emissions reductions contemplated by this title."

Section 821 of the Act provides that all affected sources subject to Title IV[3] also be required to monitor CO_2 emissions according to the same timetable as in Section 412(b) and (c), and report the data to the Administrator. These provisions are to be applied in the same manner and extent as the requirements for emission monitoring data reporting under Section 412. There is no explicit requirement in Section 821, however, to use CEMS to monitor CO_2 emissions. Using the reported data, the Agency is required to compute each affected unit's aggregate annual total CO_2 emissions, compile these data into a computerized database, and make the aggregate annual CO_2 emissions data available to the public.

4. Summary of Today's Proposed Rule

Under the proposed rule, the owner(s) and operator(s) of an affected unit (or units) would be required to install and operate a CEMS on each affected unit unless otherwise specified in the regulation. The CEMS is defined as including the following components: (1) an SO_2 pollutant concentration monitor, (2) a NO_x

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[3]The statute cites Title V and Section (Sec.) 511 in Sec. 821. However, as there is no Sec. 511 in the law, the citations are clearly typographical errors, reflecting the title and section references for earlier versions of the legislation (see e.g., H.R. 3030, Rept. 101-490, May 17, 1990). The logically correct citations are to Title IV and Sec. 412.

pollutant concentration monitor, (3) a volumetric flow monitor, (4) an opacity monitor, (5) a diluent gas monitor, and (6) a data acquisition and handling system (usually computer-based) for recording and performing calculations with the data.

Table 1, CEMS Components Required in Proposed Acid Rain program Monitoring Regulation, arrays the components of a CEMS that would be required for the monitoring of each specific pollutant parameter (i.e., SO_2, NO_x, volumetric flow, diluent gas, and opacity). The CEMS components that would be used for CO_2 are also listed, although, as mentioned previously, the Act does not mandate the continuous emission monitoring of CO_2. In all cases, a data acquisition and handling system is necessary to record, perform calculations on, and report the emission data. Table 1 also lists the units of measure proposed for each pollutant parameter.

Table 1

CEMS Components Required in
Proposed Acid Rain Monitoring Regulation

Acid Rain Monitoring Requirement (units required)	Required CEMS Monitoring Component					
	SO_2	NO_x	Flow	Opacity	Diluent Gas	Data Handling
SO_2 (lbs/hr)	yes	---	yes	---	---	yes
NO_x (lbs/mmBtu)[1]	---	yes	---	---	yes	yes
Opacity (%)	---	---	---	yes	---	yes
CO_2 (lbs/day)[2]	---	---	yes	---	yes	yes

[1] Heat input in mmBtu/hr is also required.
[2] Alternative methods may be used to monitor CO_2.

Measurements of SO_2 concentration would be combined with measurements of volumetric gas flow (exhausting from the unit or emitted as a byproduct of an industrial process) to obtain estimates of SO_2 mass emissions per unit time (in lbs/hr), as required by the Act. Flow monitors always measure gas flow rate on an actual or "wet" basis. Some SO_2 pollutant concentration monitors, however, measure SO_2 concentration on a "dry" basis (meaning that the moisture of the gas has been removed). The measurements used to calculate SO_2 emissions in lbs/hr would be on the same moisture basis. Accordingly, units that employ "dry" SO_2 pollutant concentration monitors would correct their gas flow rate measurements for moisture. Under the proposed rule, EPA would allow sources to use a variety of moisture determination methods, including standard saturation/temperature tables and continuous moisture monitors, provided the corrected flow rate measurements satisfy the performance standards for monitor certification.

Similarly, measurements of NO_x concentration would be combined with measurements of a diluent gas, either oxygen (O_2) or CO_2, exhausting from the unit to obtain the estimates of the NO_x emission rate relative to the heat input of the fuel (in lbs/mmBtu). Accordingly, the proposed rule would define a NO_x CEMS as the combination of a NO_x pollutant concentration monitor and a diluent gas monitor.

The proposed rule requires a continuous opacity monitoring system (COMS) to monitor the obscuration caused by particulate matter in the gas emission stream. Gas-fired units combusting no less than 90 percent natural gas with oil as the back-up fuel would be exempted from this opacity monitoring requirement, since these units individually, and as a group, emit very little particulate matter.

The proposed rule also exempts units employing a flue-gas desulfurization (FGD) system from the opacity monitoring requirement. Most units affected by the Acid Rain program are already required by other regulations to install and utilize a COMS; the exemption proposed here would not exempt these units from such requirements. Data from all COMS shall be sent to the applicable permitting agency.

Units that monitor CO_2 continuously would need a CO_2 diluent monitor plus a flow monitor to estimate CO_2 emissions which are to be aggregated into daily totals for reporting. The proposed rule would not require units to continuously monitor CO_2 emissions. Units that generate CO_2 emissions only by combustion would be allowed to calculate, using specified methods and procedures, CO_2 mass emissions (in lbs/day) based on the measured carbon content of the fuel and the amount of fuel combusted. Units that also generate CO_2 emissions by means other than fuel combustion -- for example, by flue-gas desulfurization (FGD) using wet limestone scrubbing -- would be required either to monitor emissions or to calculate the total amount of CO_2 generated by combustion and by the FGD process using procedures in Appendix E of the proposed rule.

Under the proposed rule, each monitor in the CEMS and the

system as a whole would be required to be installed, and its performance verified and certified by the Administrator, before it can be used in the Acid Rain program.

The following performance certification tests would be required for continuous emission monitoring systems: (1) a calibration error test for each pollutant concentration monitor, diluent gas monitor, and those flow monitors for which an approved test has been developed; (2) an electronic stability test for each flow monitor that does not conduct a daily calibration error test; (3) relative accuracy and bias tests for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x emission monitoring system; (4) a cycle response time test for the SO_2 pollutant concentration monitor and the NO_x emission monitoring system; and (5) an orientation sensitivity test and an interference test for differential pressure flow monitors only. No later than January 1, 2000, relative accuracy and bias tests would be added for the combined SO_2/flow emission monitoring system (pollutant concentration monitor and flow monitor). For continuous opacity monitoring systems, performance certification tests for calibration error, response time, zero drift, and calibration drift would be conducted according to the requirements in 40 CFR 60, Appendix B.

To certify a CEMS, the designated representative for the owner(s) and operator(s) of an affected unit would submit a request to the Administrator, who would issue a notice approving or disapproving the request. Such requests would include the following information: unit identification (including type of monitoring, emission control, and back-up monitoring systems, if any), stack diameter and height, the date and results of each performance certification test, supporting documentation to substantiate the test results, and documentation to verify that the computerized data acquisition and handling system properly calculates and converts the recorded emission data.

If the proposed system is disapproved, the owner(s) and operator(s) would need to make revisions in the equipment, procedures or methods as applicable, and resubmit a request for certification.

For each system, the proposed rule requires the development and implementation of a written quality assurance/quality control plan, which would be submitted with the affected unit's Acid Rain permit application. Daily performance checks of the monitoring equipment, including gas calibration error tests and visual and electronic inspections, would be required to be included in the plan by the proposed rule. Daily calibration error tests for flow monitors are not required,[4] but the rule would enable sources to reduce the frequency of required relative accuracy testing for flow monitors by conducting daily calibration error tests. Flow

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[4]Except for ultrasonic monitors, which are required to perform a daily zero-and-span check. This check is essentially a calibration error test.

monitors that do not conduct calibration error tests would instead conduct daily electronic stability tests. In addition to these daily tests, periodic relative accuracy test audits and bias tests would be required for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x emission monitoring system. A three-point calibration error test would also be required quarterly for all pollutant concentration and diluent monitors.

The mathematical construction of the relative accuracy statistic makes it more difficult for pollutant concentration monitors and emission monitoring systems on low-emitting units to pass these tests. Therefore, the proposed rule provides an optional (less stringent) alternative for units emitting less than 250 parts-per-million, by volume (ppmv) SO_2.

No alternative monitoring system is proposed in today's regulation as a preapproved system equivalent to a CEMS on the required statutory criteria of precision, reliability, accessibility, and timeliness. However, EPA is proposing an exception to the SO_2 continuous emission monitoring requirements for oil-fired and gas-fired units due to the relative homogeneity of the sulfur content distribution in these fuels, the close approximation to CEMS goals achievable by the available monitoring methods for these fuels, and the minimal impact of SO_2 emissions from units in these categories. These units would be required to use prescribed methods of in-line oil flow metering and oil sampling and analysis for sulfur content in order to estimate pounds of SO_2 emitted per hour when oil is being combusted. The prescribed excepted monitoring methods for SO_2 emissions closely approximate the performance of a CEMS. These units are not, however, exempted from the NO_x continuous emission monitoring requirements under Part 75.

In order to receive approval to use an alternative monitoring system in lieu of a CEMS or a component of a CEMS (e.g., SO_2 pollutant concentration monitor or flow monitor), the affected unit would be required to submit statistical evidence and other data demonstrating that the proposed alternative would provide information equivalent or superior to a CEMS. Under the proposed rule, EPA would use the performance of certified SO_2 pollutant concentration monitors, flow monitors, and NO_x emission monitoring systems as benchmarks for approving or rejecting proposals for alternative monitoring systems. Today's rule specifies procedures, analyses, and supporting documentation that would be required for demonstrating the equivalency of alternative monitoring systems to CEMS on the required criteria of precision, reliability, accessibility, and timeliness.

Affected units that are granted Phase I extensions under 40 CFR Part 72 and use qualifying Phase I technology (i.e., a technology that achieves at least a 90-percent SO_2 removal efficiency) would have to employ additional monitoring. The proposed rule requires that each such unit be equipped with an SO_2 pollutant concentration monitor and a diluent monitor for measuring SO_2 emissions at the inlet and outlet of the control device. Provisions are included in the proposed rule for demonstrating

achievement of the required 90-percent reduction in SO_2 emissions through qualifying Phase I technology, on an annual basis, from the date of start-up testing of the emission control device through 1999.

Consistent with Section 412 (a) of the Act, the proposed rule would allow the owner(s) and operator(s) of two or more affected units that utilize a common stack to install one SO_2 emission monitoring system. Where Phase I and Phase II affected units utilize a common stack, the owner(s) and operator(s) would be required to: (1) install a separate CEMS in each duct leading to the stack; (2) install separate CEMS in the common stack and in the ducts for each Phase II unit and calculate the Phase I unit emissions as the difference between the common-stack value and the sum of the Phase II unit values; (3) install a CEMS in the common stack and differentiate the individual unit emissions parametrically, or (4) declare the Phase II unit as a substitution unit in accordance with the requirements of Part 72. Where an affected unit and a nonaffected unit share a common stack, the proposed rule would provide these same options to the owner(s) and operator(s), except, in Option (4), the owner(s) and operator(s) would declare the nonaffected unit as a opt-in unit in accordance with the requirements of Part 74. If the continuous emission monitoring system is installed such that any portion of the flue gases from an affected unit can by-pass the monitoring system, a separate CEMS would be required on the by-pass flue gas stream.

Likewise, the owner(s) and operator(s) would be allowed to monitor for combined NO_x emissions in a common stack under certain conditions. If two or more units subject to the same NO_x emission limitation under Parts 72 and 76 share a common stack, they may monitor for NO_x emissions in the common stack. If two or more units with different NO_x emission limitations under Parts 72 and 76 emit through a common stack, they may either: (1) monitor for NO_x emissions for each affected unit; (2) monitor the common stack for NO_x emissions and use the most stringent NO_x emission limitation of any unit sharing the stack; or (3) monitor the common stack for NO_x emissions and submit a NO_x emissions averaging plan. If units with a NO_x emission limitation and units without a NO_x emission limitation share a common stack, they would differentiate the NO_x emissions at each unit.

All continuous emission monitoring systems would be required to be in continuous operation and to be capable of sampling, analyzing, and recording at least every 15 minutes. All emissions and flow data would be reduced to one-hour averages. Four data points would comprise a valid hour. During maintenance, repair, calibration or other required quality assurance activity periods, however, two or more data points would be allowed to comprise a valid hour. Failure of the system to acquire the required data points would result in the loss of data for the entire hour. In this event, the owner(s) and operator(s) would be required to use the prescribed procedures for calculating emissions for the missing data periods.

The proposed rule contains procedures for compiling

"information satisfactory to the Administrator" for substituting data where no valid data have been recorded for the SO_2 pollutant concentration monitor, the flow monitor, or the NO_x CEMS (consisting of the NO_x pollutant concentration monitor and the diluent gas monitor). For the SO_2 and flow monitors, where valid data have not been recorded for either monitor, the missing data procedure would apply to each monitor individually. For the NO_x CEMS, if either monitor is without a valid hour of recorded data, the data for both monitors would be deemed invalid, and substitute data would be provided for both monitors using the prescribed missing data procedures. Such information establishes preapproved information satisfactory to the Administrator. The proposed approach establishes the methods that may be used to "fill in" missing data, following the general principle that the longer the gap in the recorded data and/or the lower the annual monitor availability, the more conservative the value to be substituted. (Annual monitor "availability" refers to the number of total hours of valid data capture per year, expressed as a percentage of total unit operating hours.) For SO_2 concentration missing data, these substitute values are either an average of the values recorded in the hour preceding and the hour following the missing data occurrence, or the 90th-percentile value recorded during a preceding period of some prescribed length. During certain specified periods each of these statistics is calculated, with the higher of the two being used. In each case, the data acquisition system would relate the sulfur (ppm) emission rate to the sulfur content in the coal consumed for selection of the appropriate value. The procedure proposed for NO_x emission rate data and flow data is similar in structure, but allows missing data replacements to be calculated based on correlation with load.

Table 2 summarizes the proposed missing data procedures for SO_2 concentration data. First, if annual monitor availability is greater than or equal to 95 percent and the duration of the missing data period is 24 hours or less, the substituted value for each such hour would be the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period. If the missing data period is longer than 24 hours, the substituted value for each hour would be the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 30 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

Table 2
Summary of CEMS Substitution Criteria for
Estimating Values for Missing Data Periods
(SO_2 Concentration Data)[1]

Annual availability (%) of monitor or system	Number of hours missing (N)	Value substituted for each missing hour
Greater than or equal to 95%	N ≤ 24 hours	Average of the hour recorded before missing data period and the hour recorded after missing data period
	N > 24 hours	90th-percentile[2] over 30 days, or average of hour before and hour after, whichever is higher
Less than 95% but greater than or equal to 90%	N ≤ 6 hours	Average of the hour recorded before missing data period and the hour recorded after missing data period
	N > 6 and ≤ 24 hours	90th-percentile[2] over 30 days, or average of hour before and hour after, whichever is higher
	N > 24 hours	90th-percentile[2] over 365 days, or average of hour before and hour after, whichever is higher
Less than 90%	N > 0 hours	90th-percentile[2] over 365 days, or average of hour before and hour after, whichever is higher

1. The procedure used for NO_x emission rate and flow data is similar in structure, but allows missing data replacements to be calculated based on correlation with load.

2 I.e., 90th-percentile hourly value for the relevant sulfur content range associated with the missing data period.

The second group of procedures applies when annual monitor availability is less than 95 percent, but greater than or equal to 90 percent. A three-tiered system is proposed for this group where each tier is related to the length of the missing data period. If the missing data period is six hours or less, the substituted data value for each hour would be the average of the hour immediately before and the hour immediately after the missing data period. If the missing data period is greater than six hours but less than or equal to 24 hours, the substituted value for each hour is the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 30 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher. If the period is longer than 24 hours, the substituted value for each hour is the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 365 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

When annual SO_2 concentration monitor availability is less than 90 percent, the substituted data value for each hour of missing data would be the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 365 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

As mentioned previously, the procedure proposed for filling in missing NO_x emission rate data and flow data is similar in structure to the SO_2 missing data procedure, but allows missing data replacements to be calculated based on correlation with load, rather than fuel sulfur content.

The proposed rule also contains procedures to be used for converting the hourly emissions data for SO_2 into pounds per hour (lbs/hr) and for NO_x into pounds per million British thermal units (lbs/mmBtu). Procedures also are provided for calculating hourly emission rates of CO_2 when it is monitored continuously and for estimating daily CO_2 emissions when a monitor is not used. The rule also contains prescribed American Society for Testing and Materials (ASTM) methods, procedures, and equations for excepted monitoring methods based on oil sampling and analysis available to gas-fired and oil-fired units.

The proposed rule includes requirements for notification, recordkeeping, and reporting for the Acid Rain program. The requirements include monitoring plans to be submitted as part of the compliance plan and permitting process stipulated by Part 72; written notifications of monitor certification tests; daily recording of hourly emissions and flow data and other information; maintaining records of emissions and flow data, other measurements, and system maintenance; initial and quarterly reports of quality assurance and quality control tests for the continuous emission monitoring systems; and reports of recorded emissions, flow, unit operating status, and monitoring performance data. The proposed

rule would require the owner(s) and operator(s) to electronically report the required information on a quarterly basis as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or a modem.

The proposed Part 75 monitoring regulations do not specify a procedure for administrative appeal of determinations made by the Administrator under Part 75 (cf. 40 CFR Part 72, Subpart H). However, EPA is considering adopting such a procedure for challenges to the monitor certification requests of this Part. EPA requests comment on whether monitor certification or other specific determinations should be covered by an Administrative appeal procedure. Comments should also address whether an appeal should be permitted only for the monitoring plan as a whole, rather than for the individual determinations that underlie or are included in the monitoring plan. In addition, EPA requests comment on whether the appeal procedure set forth in support of Part 72 (the Acid Rain Permitting Regulations) should be used as the appeal procedure for Part 75 as well.

B. CEMS Description and Background

A continuous emission monitoring system (CEMS) is a system that measures, on a continuous basis, the amount of pollutants emitted into the atmosphere in exhaust gases from combustion processes or as the byproduct of manufacturing or other industrial processes. When used in its broadest sense, CEMS can also refer (as it does in Title IV) to the continuous opacity monitoring of obscuration caused by particulate matter and the monitoring of other gases such as CO_2.

Prior to 1978, EPA used CEMS for electric utilities only as an indicator that plant operators were performing proper operation and maintenance of air pollution control equipment. In 1978, with the promulgation of the New Source Performance Standards (NSPS) for fossil fuel-fired steam generators, 40 CFR Part 60, Subpart Da (Subpart Da), CEMS data were used, for the first time, to assess affected sources' compliance by comparing CEMS-measured concentrations of SO_2 and NO_x in exhaust stack gases with applicable emissions standards.

In developing today's proposed CEMS regulation for the Acid Rain program, EPA began with a review of the existing Subpart Da monitoring requirements to evaluate their applicability to the goals of Title IV. Subpart Da represents a natural starting point for the development of the Acid Rain CEMS regulation since it has become the standard reference for all subsequent federal and State CEMS regulations. The electric utility industry now looks to the CEMS provisions in Subpart Da for quality assuring their CEMS devices, whether monitoring new or existing sources, and uses them to shape their internal quality assurance programs. Also, using Subpart Da as an initial template for the Acid Rain CEMS regulation and performance standards would reduce the need to replace existing CEMS systems that have been performing reliably and accurately with new systems. Representatives from utilities, State agencies, and environmental groups, as well as members of the Acid Rain Advisory Committee (ARAC), have endorsed the approach of using Subpart Da as

the initial template for the proposed regulation.

Pivotal to this review and analysis, however, was the recognition by EPA that: (1) the market-based approach of Title IV differs significantly from the traditional control approach embodied in Subpart Da; (2) CEMS technology has improved markedly--particularly in the areas of monitor reliability, expected data capture rates, and accuracy of emissions measurements--since the promulgation of Subpart Da; and (3) incentives to promote further CEMS improvements, producing higher data capture rates and more accurate emissions measurements as the Acid Rain program matures, could be essential to maintaining confidence in the viability of the allowance trading market as a means of achieving cost-effective environmental regulation.

Moreover, the goals and monitoring objectives of the Acid Rain program are different from those of Subpart Da. A fundamental difference is the Acid Rain program's need for 100 percent accounting of all SO_2 mass emissions (in tons) from affected units each year for comparison with the allowances they hold. This contrasts with the Subpart Da approach of relating SO_2 concentrations to an emissions standard expressed in terms of pollutant mass emitted relative to the heat input of the fuel (in lbs/mmBtu). The requirement for 100 percent accounting of SO_2 emissions leads to a key difference between the monitoring objectives of Subpart Da and the Acid Rain program. Title IV of the Act requires affected units "to sample, analyze, measure, and provide on a continuous basis a permanent record of emissions and flow[.]" Another difference is the need for timely, accurate, and consistent measurements of SO_2 and NO_x emissions to support the allowance trading and the NO_x averaging components of the Acid Rain program.

Subpart Da requires affected sources to install and continuously operate SO_2 and NO_x concentration monitors to measure concentrations in the exhaust gas, and diluent gas monitors to measure the concentration of a major gaseous constituent, O_2 or CO_2, in the gaseous pollutant mixture exhausting from the unit, which is needed to convert the ppmv pollutant concentration measures into units of the Subpart Da emissions standard (lbs/mmBtu). Additionally, Subpart Da requires affected sources to install and operate continuous opacity monitors for measuring the opacity of gases emitted into the atmosphere.

In addition to these Subpart Da requirements, Section 402(7) of the Act stipulates that the Acid Rain program measure flow continuously. This has prompted EPA to expand the definition of CEMS. Under Subpart Da the gas-concentration monitors, together with a (usually computer-based) data acquisition and handling system for recording and performing calculations with the measured pollutant data, comprise a continuous emission monitoring system (CEMS). For the purposes of the Acid Rain program, the rule would define CEMS to include flow monitors, which continuously measure the volumetric flow of gas through a stack or duct. In conjunction with concentration monitors, the flow monitors will permit continuous measurement of SO_2 mass emissions per unit time (in

lbs/hr).

Notwithstanding the recognized differences between the program goals and monitoring objectives of Subpart Da and the Acid Rain program, EPA's review has indicated that not only are many of the CEMS performance requirements, certifying tests, and quality assurance procedures of Subpart Da applicable to the Acid Rain program with minor modification, but also the historical record of Subpart Da monitors establishes a baseline for defining achievable performance for today's CEMS technology. As an example, in preparation for this proposal, both EPA and the Utility Air Regulatory Group (UARG[5]) conducted independent statistical analyses of annual monitor availabilities[6] reported for SO_2, NO_x, and opacity monitors at units subject to Subpart Da requirements, in order to assess the likely performance that could be achieved by well-maintained systems based on current technology.[7] Both studies have produced essentially identical results: the average annual availability during 1988-1990 of Subpart Da pollutant concentration monitors, either SO_2 or NO_x, was above 95 percent and the average annual availability of Subpart Da opacity monitors was above 97 percent.

Similarly, both EPA and UARG analyzed monitor relative accuracy[8] values that have been submitted in periodic data assessment reports (required under Subpart Da quality assurance procedures) during 1988 and 1989 to assess the likely performance that could be achieved by SO_2 and NO_x pollutant concentration

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[5]UARG is a group of representatives of several electric utility companies which analyzes Clean Air Act implementation issues and makes recommendations on their resolution.

[6]Annual monitor "availability" refers to the expected number of total hours of valid data capture per year, expressed as a percentage of total unit operating hours.

[7]E7 - EPA AIRS CEM Subset Analysis, January 17, 1991, and Technical Note by Roberson Pitts, Inc., Assessing Data Availability at Units Subject to Subpart Da New Source Performance Standards, September 1990.

[8]"Accuracy" refers to the difference between the emissions measurements made by a pollutant concentration monitor or a CEMS and the true values of emissions. Since the true values of emissions are unknown, CEM reference method results are assumed to represent true emissions. "Relative accuracy" is a statistic commonly used to describe the systematic error (bias) and random error (imprecision) associated with data from a pollutant concentration monitor. It may also be used to describe the emissions measurement accuracy of the CEMS as a whole, as discussed later under NO_x continuous emission monitoring systems.

monitors based on current technology.[9] The EPA analysis of this data demonstrates a feature of the Subpart Da relative accuracy statistic that limits its usefulness in assessing accuracy. While the Subpart Da relative accuracy statistic ensures that all sources of monitor error (both random and non-random) do not exceed a stipulated percentage of the average reference method measurements, it does not detect consistently low CEMS measurements, i.e., low bias.[10] Consequently, monitors with statistically significant bias can still achieve "acceptable" relative accuracy. That is, monitors that show a statistical consistency in measuring low relative to reference method results could nevertheless pass a relative accuracy test under Subpart Da. Indeed, as is discussed in more detail in Section C on SO_2 monitoring below, EPA data on existing monitors show that in a significant number of cases where the Subpart Da relative accuracy test was passed, a bias test would have been failed had one been applied.

Recognizing the importance of accurate emissions measurements, EPA considered replacing or supplementing the relative accuracy statistic with separate statistical indicators of bias and precision. One approach considered uses the automated measurement methods recently adopted by the International Standards Organization (ISO) for determining SO_2 pollutant concentrations in emissions from stationary sources.[11] Other possible approaches include the t-statistic, rank sign, and randomness tests, which are generally regarded as appropriate statistical methods for detecting the presence of bias in experimental or instrumental data.

In order to investigate fully the potential advantages and possible shortcomings of these statistics, EPA has developed a computerized database of the individual data points (runs) from relative accuracy test audits (RATAs) of SO_2 and NO_x pollutant concentration monitors at 21 coal-fired units. This database contains over 1000 data points from SO_2 pollutant concentration monitor RATAs as well as information on the applicable reference method (wet chemistry or instrumental), type of monitor (extractive

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[9]"Accuracy and Reliability of CEMS at Subpart Da (Electric Utility) Facilities," Entropy Environmentalists, Inc., March 1990, and Presentation Materials, ARAC Emissions Monitoring Subcommittee Minutes, prepared by R. Roberson for UARG, February 20, 1991.

[10]The Subpart Da relative accuracy statistic cannot detect either low or high bias. As discussed in the next Section, only low bias is of regulatory concern to the Acid Rain program, since sources will find it in their economic interest to correct high bias, and only low bias threatens the emission reduction goals of the program. Therefore, the remainder of this discussion is in terms of low bias only.

[11]Standard ISO/DIS 7935, September 1990, cited in "Accuracy and Precision of CEM Systems," J. Jahnke, January 1991.

or in situ), and measurement basis (wet or dry). The database also contains analogous RATA data for NO_x pollution concentration monitors and flow monitors.

Statistical analyses performed on this database indicate that a t-statistic test (also called a "t-test") for detecting the presence of bias would effectively identify monitors that measure consistently low or high relative to the reference method. The proposed rule would incorporate a t-test, applied to low bias only, in addition to the relative accuracy test for certifying monitors. Satisfactory monitor performance in both tests would be assessed using a 95-percent confidence coefficient, as is employed in the relative accuracy test required under Subpart Da.

C. SO_2 Pollutant Concentration Monitoring

As discussed previously, EPA has relied upon the historical operating experience of SO_2 pollutant concentration monitors at units subject to Subpart Da requirements to develop proposals for: (1) design of the monitoring protocol, including sampling frequency and the basic time period for emissions accounting; (2) performance specification parameters for certifying monitors, including relative accuracy, bias, calibration error, and cycle time/response time; and (3) quality assurance and quality control procedures, including daily calibration checks and periodic relative accuracy test audits, bias tests, and three-point calibration error tests. Where the provisions of Subpart Da continue to define adequately the capabilities of today's SO_2 pollutant concentration monitors, EPA proposes to use them for the Acid Rain program, provided they are consistent with the program's goals and monitoring objectives. Where the provisions of Subpart Da no longer reflect the performance achievable with current technology or are inconsistent with the goals or monitoring objectives of the Acid Rain program, EPA is proposing different requirements.

1. System Design Considerations

a. Time Period for Emissions Accounting

Under Subpart Da, an hour is the basic time unit for the accounting of emissions. This time period is consistent with the statutory language of the Act, which lists pounds-per-hour as one appropriate unit for expressing emission quantity. It was the consensus of the Acid Rain Advisory Committee[12] that, because Title IV of the Act requires a continuous record of emissions, an hour is an appropriate unit. EPA therefore proposes today that an hour be the basic building block in accounting for SO_2 emissions under the Acid Rain program.

b. Sampling Frequency

The general provisions of NSPS (40 CFR Part 60) specify that each component of a CEMS shall be capable of taking measurements every 15 minutes (four sampling or data points per hour) or more frequently. Subpart Da of 40 CFR Part 60, however,

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[12]Docket A-90-39, II.B.27, E-28 - Emission Monitoring Subcommittee Minutes, March 20-22, 1991.

permits the use of hourly emissions data for compliance purposes if the monitor captures at least two (out of the four) data points [Sections 60.47(a) and 60.47(b)]. The intent of this provision, as described in the Subpart Da Preamble (44 FR 33581, June 11, 1979), was to accommodate those instruments that cannot obtain four equally spaced points during calibration periods.

To ensure that the hourly SO_2 concentration averages are as accurate as possible under the Acid Rain program, there was a strong inclination to require four data points in all hours for the hourly calculation to be valid. However, the desirability of such a requirement is limited by EPA's need under the Acid Rain program to require daily calibration checks of the SO_2 pollutant concentration monitor. EPA believes that the proposed daily calibration checks, combined with routine maintenance, are essential to ensure that the instrument is not "wavering" over time and producing erroneous measurements, and to quality assure the recorded SO_2 concentration data on a daily basis. The daily calibration checks required by Subpart Da, which are less rigorous than those in today's proposed rule, typically cause the monitor to be off-line, and "unavailable" for emissions measurements, for a half-hour to an hour.[13] If EPA were to require four data points for a valid measure of average hourly SO_2 concentration in all hours, at least an hour's worth of emissions data would be lost each day from otherwise acceptable monitors during the required calibration period.

EPA is proposing to continue the practice of allowing the calculation of average hourly SO_2 concentration using two data points, each representing a 15-minute period, of the normally required four (or more) data points during hours when calibration error tests or other quality assurance activities specifically required by Part 75 are being performed. During ARAC discussions, industry representatives have suggested that repair and maintenance periods, as well as periods of routine or preventative maintenance, should also be included as periods for which 2 data points are acceptable.[14] EPA agrees with this view, and is proposing to accept two data points per hour during all documented periods of calibration, quality assurance activities, repair, and maintenance.

2. Performance Specifications for Certification

EPA proposes to require the certification of each SO_2 pollutant concentration monitor, as is done under Subpart Da, before that monitor may be used to satisfy any of the continuous emission monitoring requirements under the proposed rule. This

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[13]Most operators schedule these checks to "bridge" a clock hour, so the monitor is available to sample and measure two data points in the hour before the check and two data points in the hour following the check, thus losing no hours of emissions data.

[14]E14 - Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

certification process would involve a series of tests to verify that the monitor's performance meets or exceeds EPA's minimum performance specifications with respect to: (1) relative accuracy of emissions measurements, (2) absence of statistically significant bias in emissions measurements, (3) calibration error over the expected range of SO_2 concentrations, and (4) cycle time/response time to alternating (high and low) SO_2 concentrations.

The primary intent of pollutant concentration monitor certification tests under Subpart Da is to screen out malfunctioning systems. These tests must also fulfill a different and more demanding objective under the Acid Rain program with its allowance trading market--namely, to ensure the accurate and consistent measurement of emissions across the entire range of expected SO_2 concentrations. Accordingly, while EPA is proposing to adopt the basic tenets of Subpart Da for the Acid Rain program's monitor certification process, some changes are being introduced to improve the accuracy of emissions data.

a. Relative Accuracy

EPA has traditionally used the relative accuracy statistic, discussed previously, to evaluate the accuracy by which a pollutant concentration monitor samples, measures, and analyzes pollutants in the exhaust gases emitted by a combustion process or as a byproduct of an industrial process. EPA has defined a series of reference methods for determining specific pollutant concentrations in a gaseous pollutant mixture that are defined as the true values of the pollutant concentration. The relative accuracy performance specification tests for SO_2 concentration would consist of a minimum of nine sets of paired comparisons between monitor measurements and contemporaneous reference method measurements of flue gas SO_2 concentration in parts per million by volume (ppmv). Under Subpart Da the comparison of paired sets of monitor measurements and contemporaneous reference method measurements of pollutant concentrations in the gas is used to provide an independent assessment of monitor accuracy under actual operating conditions. Hence, reference method test results are assumed to be equivalent to, or a proxy for, the true values of the pollutant concentrations. EPA has defined four reference methods for evaluating the accuracy of SO_2 pollutant concentration monitors.[15] Most units subject to Subpart Da requirements currently use either Method 6 (wet chemistry) or Method 6C (instrumental).

Subpart Da established a relative accuracy of 20 percent as the standard for defining acceptable monitor performance with respect to the accuracy of emissions measurements. Both the EPA and UARG analyses[16] of the relative accuracies reported by SO_2

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[15]40 CFR Part 60, Appendix A, Methods 6, 6A, 6B, and 6C.

[16]"Accuracy and Reliability of CEMS at Subpart Da (Electric Utility) Facilities," Entropy Environmentalists, Inc., March 1990, and Presentation Materials, ARAC Emissions Monitoring

pollutant concentration monitors at units subject to Subpart Da requirements indicate that over 90 percent of these monitors routinely perform better than the 20-percent standard. All the monitors performing below this standard are located at "low-emitting" units, defined as units emitting at the rates of 0.5 lb SO_2/mmBtu or less. With the exception of these low-emitting units, all Subpart Da monitors routinely perform better than the 20-percent standard.

Subpart Da provides low-emitting units with the option of using an alternative (less stringent) standard. EPA considered proposing a similar exception for low emitters at ±10 percent of the mean difference between the reference and CEMS values. However, this approach would not completely avoid the problem that as the emissions get small enough the percentage increases disproportionately to the significance of the difference in emission rate. This is because the ratio, like the relative accuracy statistic, tends to produce a large relative percentage error for low-emitting units since its denominator is the mean of the emissions values determined by reference method tests, which will be a small number for low emitters. EPA believes that an absolute limitation provides the most appropriate protection for low-emitting sources, and accordingly proposes a limitation of ±15 percent ppmv. This approach appropriately affords the lowest-emitting units the most latitude, and EPA's analysis of its database indicates that approximately 90 percent of existing sources are currently within this limit.

Because of the importance of accurate emissions measurements to the allowance trading market, EPA is proposing a relative accuracy of 10 percent as the standard for defining acceptable SO_2 pollutant concentration monitor performance under the Acid Rain program. EPA believes that this relative accuracy standard more closely reflects the performance that can be achieved by well-maintained monitors based on current technology than does Subpart Da's 20-percent standard. Analyses on EPA's database of SO_2 pollutant concentration RATA data indicate that over 89 percent of the RATAs conducted during 1987-1990 at non-low-emitting units subject to Subpart Da requirements produced relative accuracies of 10 percent or less on a ppmv basis.[17]

Like Subpart Da, today's proposal includes a less-stringent alternative standard for low-emitting units. The proposed alternative standard would apply to units emitting at the rates of 250 ppmv (approximately equivalent to 0.5 lb SO_2/mmBtu) or less. It would require that the average difference between the monitor measurements and the values determined by the reference method tests be no greater than 15 ppmv.

Subcommittee Minutes, prepared by R. Roberson for UARG, February 20, 1991.

[17]Study by The Cadmus Group, W. Warren-Hicks, August 14, 1991.

b. Bias

As mentioned previously, the relative accuracy statistic of combines statistical descriptors of bias and precision in a manner that allows monitors with statistically significant bias (measuring consistently low or high relative to the reference method) to achieve "acceptable" relative accuracy. The existence of statistically significant low bias would lead to understated emissions, thereby threatening the achievement of the emission reduction goals of the Act as well as the market's confidence in the link between allowances and actual emissions. Therefore, a method to detect and eliminate such bias is proposed as part of the Acid Rain monitoring program.

As discussed below, in today's proposal EPA would require sources to test for bias using relative accuracy test audit (RATA) data. EPA considered whether it would be possible to ascertain the presence of bias using data from the daily calibration error tests, rather than RATA data. In EPA's judgment, the proposed RATA-based procedure has the added benefit of being an independent check of the monitor under actual operating conditions. The RATA relies on the reference method as a second, separate means of detection. This approach provides a check of the entire system and is likely to detect any problems which may develop either in the stack or along the sampling train and data system. Thus, potential sources of bias experienced only under actual operating conditions are detected by this approach, a judgment confirmed by a professional engineering study[18] and discussions with industry experts. Based on these considerations, EPA believes that a RATA-type test, which employs a reference method independent of the CEMS, provides the best basis for detecting bias. As discussed below, EPA requests comment on the merits of this approach.

EPA has evaluated the probable incidence of bias in otherwise acceptable monitors using its computerized database of SO_2 pollutant concentration RATA data from units subject to Subpart Da requirements.[19] EPA has employed four types of statistical tests to assess monitor bias: (1) the ISO (International Standards Organization) test which combines a t-test with both a bias threshold defined on the span of measurement and an upper limit on the CEMS variance; (2) a t-test that does not incorporate either the ISO's bias threshold or its limit on CEMS variance; (3) a

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[18]"Stationary Source Emissions -- Determination of the Mass Concentration of Sulfur Dioxide -- Performance Characteristics of Automated Measuring Methods," pp. 11-12, Technical Committee 146, International Standard 7935, International Standards Organization, The Hague, The Netherlands, 1989.

[19]Technical Notes, Kilkelly Environmental Associates, W. Warren-Hicks, dated April 25, 1991 and May 23, 1991.

nonparametric[20] rank sign test; and (4) a nonparametric randomness test.

EPA has rejected the nonparametric test options for certifying monitors because experience indicates that the SO_2 pollutant concentration RATA data approximate a normal distribution. With normally distributed data, the two nonparametric statistical tests would be more likely to yield erroneous results than either the ISO or the t-test for bias. Furthermore, the ISO and t-test have been shown to yield reliable results even when data are only approximately normally distributed. They also can provide information about the level of confidence associated with a particular result. The "level of confidence" refers to the degree of uncertaincy associated with the acceptance or rejection of the hypothesis being tested. For example, if a monitor fails a bias test at the 95-percent level of confidence, the probability is only five percent that this monitor was incorrectly rejected -- i.e., that the monitor was not actually measuring either consistently low or consistently high relative to the reference method. Subpart Da uses the 95-percent confidence coefficient in all its statistical tests for certifying monitors and quality assuring CEMS data.

The ISO test is an attractive option because of its credibility internationally. This method uses a t-test procedure to detect monitor bias and, at the same time, establishes a limit on the allowable variance of the CEMS. In setting limits on the variance of the CEMS, however, the ISO test appears to be too demanding for current U.S. CEMS technology: less than 30 percent of the SO_2 RATAs in EPA's database from units subject to Subpart Da requirements would pass this bias test at the 95-percent level of confidence.

Of the available tests, in EPA's judgment the t-test at the 95-percent level of confidence is the most satisfactory method for screening out biased monitors since, like the ISO method, it takes advantage of the normal data distribution to provide a less error-prone test than either of the nonparametric approaches, and yet does not present too stringent a threshold for current U.S. CEMS technology. The test would be applied to detect low bias only, since only low bias threatens the emission reduction goals of the Act, and in any case it will be in the economic interest of sources to detect and correct high bias. EPA believes that the t-test, at a 95-percent level of confidence, applied to low bias only, provides a standard that can be achieved by well-maintained SO_2 pollutant concentration monitors based on current technology. Seventy percent of the SO_2 RATAs in EPA's database passed this test even though the monitors were not required to meet any type of bias performance specification. Moreover, since a substantial number of RATAs in EPA's database were performed as long ago as 1986-1988, it can be assumed that subsequent improvements in monitor technology

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[20]"Nonparametric" means that the test is appropriate for data that may not conform to the normal (bell-shaped) distribution.

will yield even better performance on the bias test.

In today's proposal, EPA would require the t-test at the 95-percent level of confidence, applied to low bias only,[21] using the same data as that used to certify relative accuracy, as the certification test for SO_2 concentration monitor bias. The recorded SO_2 concentration data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in Appendix A of the rule. Monitors failing the bias test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed bias test and the time of the next successful bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

EPA has relied on the relative accuracy test as a key element of its Subpart Da requirements. The test has a number of advantages: it is an already-accepted part of several of EPA's other regulatory programs, it is well-understood by the regulated community, and passage of the test has been demonstrated as achievable by most existing units. However, as noted earlier, the relative accuracy test represents a combination of a measure of monitor bias and of the random variance in CEMS measurements (relative to the reference method), and it has been suggested that there may be supplemental tests (e.g., t-test, rank sign test) that would be more effective in assuring measurements that are sufficiently accurate to meet annual emission reduction requirements and support allowance trading. In addition, some have argued that there is measurement error associated with the reference method (as well as with the CEMS) and that because of this error the relative accuracy and bias tests could result in incorrect conclusions on the inaccuracy or bias of the CEMS. As a result, EPA is interested in further comments with respect to the following concerns that have been raised with regard to today's proposal:

* What characteristics (for example, in terms of measurement error) are necessary to ensure compliance with the annual emission targets set under the Clean Air Act?

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[21]Considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with an alpha value of 0.025. Thus, in Table 8-1 in Appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

* Given the proposed requirement that units conduct a daily calibration test, how effective is the relative accuracy test in assuring a sufficiently accurate measurement of annual emissions? Similarly, how effective is the bias test in meeting this objective?

* Are there alternative ways of structuring the relative accuracy and bias tests that would be as effective, or more effective, and less costly in assuring measurements sufficiently accurate to meet annual emission requirements and support allowance trading?

* Are there cases where, given other quality data checks (and the resulting confidence in the data), an exemption from the bias test could be warranted and still have the monitoring data necessary to assure achievement of the emission-reduction goals and support allowance trading? For example, it has been suggested that a relative accuracy threshold be set below which no bias test would be required, i.e., a relative accuracy of 5 percent, 3 percent, or 2.5 percent. Also suggested was a threshold for the mean difference between the reference method and the CEMS (expressed as a percentage deviation of the arithmetic mean of the CEMS measurements from the arithmetic mean of the reference method measurements) below which no bias test would be required, i.e., at a mean difference of 5 percent or 2.5 percent.

These questions apply to bias testing for flow and NO_x monitors, covered in Sections VI.D.2 and VI.E.2, respectively, as well as for SO_2 monitors, covered in this Section. EPA requests comment on these questions with respect to any or all of these pollutants.

c. Calibration Error

EPA is proposing to expand Subpart Da's two-point (low and high) calibration error test for monitor certification into a three-point (low, mid-range, and high) test under the Acid Rain program to ensure the accuracy of SO_2 emissions measurements throughout the entire range of expected values. A calibration error test "challenges" the monitor under controlled conditions with gases of known pollutant concentrations in order to evaluate the closeness of its emissions measurements to different certified concentration levels of the calibration gases. As outlined below in Section 3 on quality assurance and quality control procedures, the gases used to supply the known concentrations are required to be either standard reference material or Protocol 1 gases certified to be within 2 percent of the corresponding standard reference material.

For calibration error tests under Subpart Da, the high level of the pollutant concentration is normally between 1.25 and 2 times the applicable emissions standard and the low level is normally zero. Under Subpart Da, accuracy in measuring SO_2 emissions is necessary only to the extent of determining whether or not the

unit's emissions exceed the applicable emission rate standard. Once the emissions are shown to exceed the applicable standard, however, the accuracy of the monitor's measurements are no longer important. Moreover, Subpart Da constrains units to operate within a narrow range of SO_2 concentrations, so monitor accuracy over a wide concentration range is not a concern.

Under the Acid Rain program with its allowance trading market, however, units can operate over a potentially wide range of SO_2 concentrations. Some units are expected to emit SO_2 concentrations at substantially higher levels than those experienced under Subpart Da. Under the Acid Rain program, SO_2 emissions must be measured accurately throughout the entire range of expected SO_2 concentrations. The proposed rule would require calibration error tests at three levels, defined as a percentage of the expected range of SO_2 concentrations, as follows: (1) 0-20 percent for the low level, (2) 40-60 percent for the mid-range level, and (3) 80-100 percent for the high level. The "high" level of SO_2 concentration used for calibration error tests under Subpart Da would probably correspond, for many units, to the "mid-range" level under the Acid Rain program.

EPA proposes to use Subpart Da's performance specification of 2.5 percent for calibration error for monitor certification under the Acid Rain program. That is, to qualify for certification, a monitor's measurements of SO_2 concentrations would be required to not deviate from the known calibration gas values by more than 2.5 percent for each of three concentration (low, mid-range, and high) levels.

d. Cycle Time/Response Time

EPA proposes to use the cycle time/response time test required for monitor certification under Subpart Da for the Acid Rain program. The objective of this test is to determine how quickly the monitor responds to changes in pollutant concentration. The cycle time/response time test "challenges" the monitor with alternating gases of known (high and low) pollutant concentrations and records the amount of time required for the monitor to register 95 percent of the difference between the two concentration values. EPA proposes to use Subpart Da's performance specification of 15 minutes as the maximum time allowed.

3. Quality Assurance and Quality Control Procedures

As in the case of the performance specifications for the certification of SO_2 monitors, EPA has relied on Subpart Da's procedures for quality assurance (QA) and quality control (QC) of monitor accuracy and recorded emissions data as the initial template for defining these requirements under the Acid Rain program. Subpart Da QA/QC procedures are specified in Appendix F, 40 CFR Part 60. They consist of a series of tests to be performed periodically (daily, quarterly, semi-annually, and annually) to ensure that the monitors, once certified, continue to operate reliably and accurately. Also included in Subpart Da are specifications for maintaining records of QA/QC test dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA and other applicable regulatory

authorities.

Under Subpart Da, quality assurance procedures are needed to assess an affected unit's compliance with applicable emissions standards on a 30-day rolling average basis. The Acid Rain program, however, will require a more timely assessment of the accuracy of recorded emissions data for the proper functioning of the allowance trading market. Timely and accurate emissions data will help foster certainty in the market, thus facilitating trades, whereas unknown or inaccurate emissions data could lead to the hoarding of allowances as a compliance "cushion." Thus, EPA is proposing to require affected units to quality assure each day's recorded emissions data within 24 hours. Also, as was done with the performance specifications for the certification of monitors, EPA is proposing other changes to Subpart Da's QA/QC procedures to improve the accuracy of emissions measurements.

a. Daily Calibration Error Test

As mentioned previously, EPA is proposing to expand Subpart Da's daily calibration drift checks for the SO_2 pollutant concentration monitor into daily two-point (low and high concentration) calibration error tests so as to quality assure the recorded emissions data on a daily basis. Under the Acid Rain program, affected units would be required to use either Protocol 1 gases or gases that are traceable to either a standard reference material gas or a National Institute of Standards and Technology (NIST)/EPA-approved certified reference material gas for these daily calibration error tests, in addition to the quarterly calibration error tests, as required under Subpart Da. The accuracy of emissions measurements is directly related to the quality of gases used in the calibration error tests. Previous studies have shown that the "known" SO_2 concentration in some commercially available test gases may deviate from the specified value by as much as 18 percent, which is not acceptable quality.[22]

"Standard reference material gases" are gases of known pollutant concentration that are certified and distributed by the National Institute for Standards and Technology. These gases are of the highest quality, but are available only in limited quantities. "Protocol 1 gases" are manufactured according to a standard protocol that uses samples of standard reference material gases and compares the pollutant concentration in the Protocol 1 gas against its benchmark in the standard reference material gas.

Recent audits of Protocol 1 gases indicate that their pollutant concentrations are within five percent of standard reference material benchmark in over 90 percent of the gases

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[22]"Performance Audits of EPA Protocol Gases and Inspection and Maintenance of Calibration Gases," R. Wright, E. Tew, C. Decker, D. von Lehmden, and W. Barnard, Journal of the Air Pollution Control Association (JAPCA), Vol. 37, No. 4, April 1987.

tested.[23] EPA was concerned that this level of quality control would not be sufficient for the Acid Rain program, and therefore conducted an examination of the current quality of the Protocol 1 calibration gases sold on the market today. This examination showed that, for 90 percent of the samples, the pollutant concentrations were within 2 percent of the concentration of standard reference materials, constituting a marked improvement in the quality over previous figures.[24] Given the results of the aforementioned EPA survey and the fact that the accuracy of Protocol 1 gases is directly related to the accuracy of the CEMS, the proposed regulation would require that all calibration gases used in the Acid Rain program be vendor-certified to be within 2 percent of the indicated value, as measured against the standard reference material benchmark. Protocol 1 gases would be audited annually and the results published.

Field personnel from EPA Regional Offices have observed that most units already use Protocol 1 gases for daily calibration drift checks of their SO_2 pollutant concentration monitors. Consequently, the requirement to use Protocol 1 gases daily should not increase the burden on the regulated community. This assessment has been confirmed by members of the ARAC Emissions Monitoring Subcommittee, who recommended that EPA require the use of Protocol 1 gases for daily calibration error tests under the Acid Rain program.[25]

A concern was raised by a few electric utilities that employ a certain type of in situ monitor which has a built-in gas reference cell for calibration drift checks. For this type of monitor, it would be cumbersome to perform daily calibration error tests using Protocol 1 gases. However, these monitor models were initially fabricated over 10 years ago; many units have already replaced them with newer models that are amenable to daily calibration error tests using Protocol 1 gases. EPA expects that the remainder of these monitors may be replaced in the reasonably near future. Therefore, EPA solicits comment as to whether such an exception would be warranted, the conditions of any such exception, and whether the quality, stability and reliability of the calibration gas in the built-in cells of these monitors would satisfy the Protocol 1 criteria.

Subpart Da has two complementary standards for defining unacceptable monitor performance with respect to daily calibration drift error: (1) drift exceeds four times the performance

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[23]"Accuracy Assessment of EPA Protocol Gases in 1988", R. Wright, C. Wall, C. Decker, and D. von Lehmden, JAPCA Notebook, Vol. 39, No. 9, September 1989.

[24]Draft 1991 audit results, memorandum to EPA, R. Shares, Research Triangle Institute, August 13, 1991.

[25]E14 -- Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

specification of 2.5 percent in a given day, and (2) drift exceeds twice the specification for each of five consecutive days. A monitor is considered "out of control" if it fails the daily calibration error test on the basis of either of these standards. The recorded emissions data from such a monitor would be considered invalid for compliance purposes.

EPA believes that the calibration error standards under Subpart Da are neither sufficiently stringent to ensure the accuracy of emissions measurements nor reflective of today's CEMS technology achievements. Accordingly, EPA proposes to adopt the calibration error standard used in the Commonwealth of Pennsylvania's CEMS regulations for the Acid Rain program--namely, drift should not exceed 5 percent (twice the specification of 2.5 percent) in a given day. The recorded emissions data from a monitor that fails this calibration error standard would be considered invalid, or "missing," prospectively until monitor drift is brought under control (within specification).

b. Periodic Performance Tests

As discussed earlier, the Acid Rain program requires emissions data which is both more comprehensive and more accurate than that required under Subpart Da. The most important factor in obtaining such data is accurate and reliable monitoring. EPA proposes to assure this enhanced accuracy and reliability by requiring monitor performance testing that is more frequent and comprehensive than the tests in Subpart Da. Specifically, EPA proposes to require three kinds of performance tests on SO_2 concentration monitors -- a relative accuracy test audit, a bias test, and a three-point calibration error test -- to be run at varying intervals, depending on the type of test and the results obtained. With the exception of the bias test, the recorded SO_2 concentration data from a monitor that fails any of these tests would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required performance standard. In the case of the bias test, concentration data that fails would be adjusted to compensate for bias until the system is corrected and passes a subsequent bias test.

i. Relative Accuracy Test Audit

As discussed elsewhere in this preamble in the section on performance specifications and standards, a relative accuracy test audit, or RATA, consists of nine sets of paired comparisons between the monitor's pollutant concentration measurements and the values determined contemporaneously by a reference method. The proposed relative accuracy standard for SO_2 pollutant concentration monitors in the RATA is identical to that proposed for the monitor certification tests. That is, under the proposed rule, SO_2 pollutant concentration monitors would be required to achieve relative accuracies of 10 percent or less in the RATAs. The recorded SO_2 concentration data from a monitor that fails a RATA would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required performance standard.

EPA is proposing to require semi-annual RATAs for SO_2 pollutant concentration monitors, with one exception described below. This frequency is consistent with the practice commonly followed in the clean coal technology program, and is judged to be sufficiently frequent to assure that owner(s) and operator(s) will give proper attention to monitor maintenance while avoiding unnecessarily frequent testing. In deliberations over the achievable level of monitor performance, EPA considered the cumulative distribution of relative accuracy results for SO_2 concentration monitors in EPA's database of relative accuracy test audits (RATAs). As previously mentioned, the results indicated that 89 percent of the RATAs would have passed at the 10 percent level of relative accuracy being proposed in today's notice. Moreover, the results showed that 69 percent and 45 percent of the RATAs would pass at the 7.5 percent and 5 percent levels, respectively, even though they had been required to meet only the Subpart Da threshold of 20 percent. In discussions with electric utility officials, however, it became clear that disagreement persists as to what these data show regarding the achievable level of relative accuracy over a larger universe of units. While these officials agree that relative accuracies below 10 percent are clearly achievable in some cases, they believe the evidence is insufficient to show that all installations can meet such a requirement.

At the same time, in these discussions, it became clear that both EPA and the utility representatives agree that the achievement of relative accuracies substantially better than 10 percent is an indication of especially good design, maintenance, and quality control, and that such results should permit the reduction in the frequency of subsequent testing. Given these facts, EPA is proposing a reduced RATA frequency for those monitors that achieve a relative accuracy of 7.5 percent or better[26]. These monitors would be allowed to reduce the subsequent RATA frequency from semi-annual to annual, and to retain this frequency as long as relative accuracy remains at 7.5 percent or better. This feature reflects EPA's judgment that the achievement of 7.5 percent reflects a monitor performance which allows sufficient confidence in monitor quality control to permit extending the inter-test period. Further, EPA agrees that this incentive-based approach to accuracy improvement is a sensible way to encourage advances in the monitoring program. Table 3 summarizes the required RATA frequency as a function of achieved relative accuracy.

Table 3

RATA Frequency for SO_2 Concentration Monitors

Relative Accuracy	Required RATA Frequency

[26]Sources meeting the 10% requirement but not achieving a relative accuracy of 7.5% or better would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve 7.5%, and thereby lower their RATA frequency.

≤10%	Semi-Annual
≤7.5%	Annual

ii. Bias Test

The periodic bias tests on SO_2 pollutant concentration monitors for the Acid Rain program would be conducted with the same frequency and at the same time as the RATAs, would employ the RATA data, and would be identical to the bias test described previously for monitor certification. The proposed performance standard for SO_2 pollutant concentration monitors in the bias test is also identical to that proposed for monitor certification. That is, under the proposed rule, SO_2 pollutant concentration monitors would be required to pass a t-test, applied to detect low bias only, at the 95-percent level of confidence. As discussed previously, the recorded SO_2 concentration data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in Appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

As proposed, the bias test regulations would allow a source to re-take the bias test at any time in order to attempt to pass or reduce the size of the bias data adjustment. In discussions about bias test design, some have voiced the concern that sources saddled with a large bias adjustment factor might take advantage of natural test-to-test variability by re-running the RATA/bias test a number of times until, by chance, they passed the test or at least achieved a lower adjustment factor. Such a procedure would be analogous to taking a large amount of RATA data and picking out the best runs to show achievement of a relative accuracy standard. Existing procedures governing the conduct of RATAs prevent this tactic (results of multiple tries must be averaged, and consecutive runs must be used) and it has been suggested that analogous strictures are needed in the bias case. As an example of such a stricture for bias, the rule could include a requirement to use the results of all runs up to a maximum of 36 paired samples. This would improve the quality of the bias assessment as more trials were attempted.

On the other hand, EPA wants to encourage sources to "fix" biased monitors and pass the bias test, rather than simply accepting the adjustment factor. Any contemplated limitation on the number of attempts to pass must take this into consideration, since sources would have less incentive to fix biased monitors if

they had to wait until the next scheduled RATA/bias test to be rid of the adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

iii. Three-Point Calibration Error Test

EPA proposes to require a quarterly three-point calibration error test on SO_2 pollution concentration monitors for the Acid Rain program. This test would be identical to the three-point calibration error test described previously for monitor certification. Under the proposed rule, a monitor's measurements of SO_2 concentrations would not be allowed to deviate from the known values by more than 5 percent for each of three concentration (low, mid-range, and high) levels. Many industry representatives indicated that this limitation was inadequate based on the variability of the quality of the calibration cylinder gas. EPA agrees with the underlying concern, but believes that the 5 percent deviation will be achievable due to the addition of the requirement for vendor certification of the calibration cylinder gas to the 2 percent level.

In developing this standard, EPA considered a requirement of 2.5 percent accuracy, identical to the certification requirement. Such a standard might be achievable, given that the most recent EPA survey found that 90 percent of sampled Protocol 1 gases were within 2 percent of the value of standard reference materials. However, EPA believes it is more reasonable to allow the calibration error to vary as much as 5 percent on quarterly assessments. Several manufacturers have indicated that this standard is readily achievable with their instruments. Furthermore, the Commonwealth of Pennsylvania requires a 3-point calibration error test with a 5 percent accuracy standard, and monitors there have had little trouble satisfying these requirements.[27]

4. Monitoring of SO_2 Reductions from Qualifying Phase I Technologies

Section 402(19) of the Act defines a "qualifying phase I technology" as "a technological system of continuous emission reduction which achieves a 90 percent reduction in emissions of sulfur dioxide from the emissions that would have resulted from the use of fuels which were not subject to treatment prior to combustion." Under subsection 404 (d) of the Act, a Phase I unit equipped with a qualifying Phase I technology or transferring its emissions reduction requirement to a unit using a qualifying Phase I technology may apply for a two year extension in meeting the Phase I sulfur dioxide requirements and for extra allowances from

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[27]"Highlights of Pennsylvania's Continuous Emission Monitoring System Quality Assurance Program," S. Darling, Pennsylvania Department of Environmental Resources, presented at 1988 Joint Power Generation Conference, Philadelphia, Pa.

a special reserve.[28] In order to determine if units given an extension are eligible for the Phase I extension reserve allowances, EPA must receive information to verify that the emissions reduction technology actually reduces sulfur dioxide emissions by 90 percent.

EPA is proposing both a start-up demonstration test and an annual demonstration of the sulfur dioxide removal efficiency achieved by units that are reducing sulfur dioxide emissions for the purpose of receiving a Phase I extension. The initial test would require a thirty day average of the sulfur dioxide emission rate in pounds of sulfur dioxide per million British thermal units (lb/mmBtu) at the inlet (entrance) and outlet (exit) of the emission controls, similar to the start-up performance test required for sulfur dioxide emission controls under NSPS. Both the Agency and the owner(s) and operator(s) of the unit would be able to evaluate if the emission controls were capable of achieving a 90 percent reduction of sulfur dioxide.

EPA considered whether to require this thirty-day test to apply at <u>all</u> times when emissions are produced by the unit. However, several electric utility representatives have pointed out that short duration malfunctions and periods of start-up and shutdown could adversely affect an average sulfur dioxide removal efficiency when the average is calculated using only 30 days' worth of data.[29] Furthermore, the Agency recognizes that there will probably be more problems and malfunctions during the first few months of operation of the emission reduction controls. Accordingly, EPA is proposing that during this initial 30 day test, calculations will not include emissions data monitored during periods of malfunctions, start-up, or shutdown.

EPA also considered measuring sulfur dioxide emissions in pounds per hour (lb/hr) at both the inlet and outlet of the emission controls. A measurement of sulfur dioxide concentration alone might not be sufficient to determine the sulfur dioxide removal efficiency of the emission controls because of the possibility of air leaks, differences in moisture content of the measured gases, or other differences between the gases at the inlet and the outlet of the controls. This can be prevented by measuring emissions in pounds per hour with a sulfur dioxide pollutant concentration monitor and a flow monitor, or by measuring emission rate in pounds per million British thermal units with a sulfur dioxide pollutant concentration monitor and a diluent monitor for oxygen or carbon dioxide. EPA considered requiring monitoring with a flow monitor and a sulfur dioxide pollutant concentration monitor at both the inlet and the outlet. This would be consistent with monitoring the pounds per hour of sulfur dioxide for comparison with allowances held. However, several utilities which intend to

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[28]<u>See</u> 40 CFR Part 72, Subparts D and L.

[29]Letter from Illinois Power Company, Phase I Extension Monitoring Proposal, August 23, 1991.

apply for Phase I extensions are concerned that it may be difficult to install a flow monitor at the inlet to emission controls. They have suggested that it would be easier to install a diluent monitor and a sulfur dioxide pollutant concentration monitor at both the inlet and the outlet to the emission controls for purposes of this determination.[30] EPA agrees that this would be sufficient.

The Agency is also proposing a continuing demonstration of the sulfur dioxide removal efficiency to determine which sulfur dioxide emission reduction technologies achieve a 90 percent sulfur dioxide emissions reduction on an annual basis. The continuing demonstrations would require continuous monitoring of sulfur dioxide emission rate (lb/mmBtu) at the inlet and outlet over the course of each year from start-up of the emission controls until the end of Phase I. EPA considered requiring an annual 30-day test, similar to the initial 30-day test, to demonstrate continuing compliance. This has the advantage of allowing the test to be repeated during the same calendar year if the emission controls failed the test, or if insufficient monitoring data were gathered. However, various electric utility representatives have indicated that since compliance with allowances held is on an annual basis, compliance with the 90 percent sulfur dioxide reduction should also be on an annual basis.[31] EPA agrees that the statutory language could be interpreted this way, and thus, is now proposing compliance on an annual average basis. Since the annual sulfur dioxide emissions must actually be reduced by 90 percent over the course of the year, emissions data from <u>all</u> periods of combustion would be included in the calculation, even during periods of start-up, shutdown, and malfunctions. Because the emission rates would be averaged over 365 days instead of just 30 days, there would also be little problem with individual emission control shutdowns seriously affecting the annual average.

The Act's requirement for a 90 percent sulfur dioxide reduction was designed to encourage the use of highly efficient emission control devices, such as wet limestone scrubbers. However, the wording of the definition of qualifying Phase I technologies implies that a combination of technologies could be used, such as coal washing and a dry lime scrubber. Accordingly, EPA proposes that fuel pretreatment may also be included in calculations of sulfur dioxide emission reduction for qualifying Phase I technologies.

D. <u>Flow Monitoring</u>

In order to meet the Act's requirement of continuous recording of volumetric flow, all affected units would be required to install and operate a flow monitor as part of their continuous emission monitoring systems for SO_2. A flow monitor continuously measures

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[30]UARG letter, August 6, 1991.

[31]Letter from Illinois Power Company, Phase I Extension Monitoring Proposal, August 23, 1991.

the volumetric flow rate of exhaust gas through a stack or duct (also called a "flue"). When combined with an SO_2 pollutant concentration monitor and a data acquisition and handling system, a flow monitor can provide continuous estimates of SO_2 mass emissions per unit time (in lbs/hr). Such estimates are needed to aggregate SO_2 mass emissions into tons per year for comparison against allowances held.

EPA is proposing the use of flow monitors in today's rule. The Agency and some States have documented experience in using flow monitors for continuous emission rate monitoring.[32] Further, utilities have used flow monitors for over a decade to continuously monitor the flow of air to the boiler and for related process control applications.[33] Because flow monitors have not generally been required at electric utility sources, fewer data are available to document the reliability and accuracy of flow monitors for these sources than are available for pollutant concentration monitors. However, EPA believes the data are sufficient to support the proposed flow monitoring requirements. Some ARAC participants have endorsed EPA's position that flow monitors currently represent the only proven, direct method for continuously measuring flow that would satisfy Title IV's objectives.[34] Other monitoring methods that have been suggested such as feedwater flow rate, electrical output, or steam flow rate correlations provide only indirect estimates of flue gas flow. A review of these methods indicates that none have been shown to be especially

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[32](1) "Continuous Measurement of Total Gas Flow Rate from Stationary Sources," U.S. EPA, RTP, NC, Publication EPA-650/2-75-020, February 1975; (2) "Continuous Emission Rate Monitoring Systems On-Site Inspections at Coal-Fired Power Plants," prepared by Entropy Environmentalists, Inc., for U.S. EPA, May 11, 1990; (3) Flow Monitoring, EPA Issue Paper for the Acid Rain Advisory Committee, April 1991; (4) 40 CFR Part 52, Appendix E, "Performance Specifications and Specification Test Procedures for Monitoring System for Effluent Stream Gas Volumetric Flow Rate"; (5) 40 CFR Part 60, Appendix B, "Performance Specification 6 - Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources"; (6) 40 CFR Part 60, Appendix G, "Provisions for an Alternative Method of Demonstrating Compliance with 40 CFR 60.43 for the Newton Power Station of Central Illinois Public Service Company"; and (7) regulations in State Implementation Plans (SIPs) governing the operations of municipal incinerators.

[33]"Continuous Emission Rate Monitoring Systems On-Site Inspections at Coal-Fired Power Plants," Entropy Environmentalists, Inc., May 11, 1990.

[34]Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, April 29-30, 1991.

accurate or practical.[35]

The studies cited above indicate that flow monitor annual availability is comparable to pollutant concentration monitor annual availability and that plant personnel have confidence in flow monitor performance. The average annual availability of flow monitors situated in the exhaust stacks of five coal-fired utilities and three industrial plants, as reported by plant personnel, was above 95 percent during 1989-1990, and all but one of these monitors had availabilities of 95 percent or better. This informal survey included all the main types of flow monitors that are currently being used for continuous emission rate monitoring. The lowest annual availability reported was 90 percent.[36]

There are three main types of flow monitors currently being used for the continuous monitoring of flue gas flow: ultrasonic, differential pressure, and thermal. Although all flow monitors estimate the flue gas flow rate by multiplying the cross-sectional area inside the flue (stack) by the average gas velocity, each type employs a different principle to measure average gas velocity. Ultrasonic flow monitors determine average gas velocity directly by measuring the time it takes for sound bursts to travel between two transceivers, one located downstream of the other. Differential pressure flow monitors determine average gas velocity by measuring the pressure at one or more points in the flue gas stream, and using the established relationship between gas pressure, temperature, molecular weight, and velocity. Thermal flow monitors use the same established relationship to determine average gas velocity, but they measure the difference in temperature between a heated and an unheated element in the flue gas stream.

While flow monitoring is a proven technology, today's rule represents the first major air pollution control regulation to require flow monitors for the continuous monitoring of flue gas flow at electric utility sources. Accordingly, utilities in the U.S. have had limited experience in the installation, operation, and maintenance of flow monitors for this particular application, and this limited experience has led to some concern about the reliability and accuracy of flow monitors, particularly in wet stack environments (e.g., downstream of a wet scrubber). Some electric utility representatives have suggested that in lieu of requiring Phase I units to continuously monitor flow, as mandated by the Act, EPA and the electric utility industry should cooperatively establish a two-to-three year flow monitor technology

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[35]IIA-48,"Utility Boiler Parameter Monitoring for Determination of Flue Gas Flow Rates," J. Richards, February 4, 1989.

[36]E31 - Flow Monitoring, EPA Issue Paper for the Acid Rain Advisory Committee (ARAC), April 1991.

evaluation/demonstration project.[37] However, EPA believes the available knowledge is sufficient to support the proposed requirement for flow monitors in Phase I as well as Phase II.

In addition, a recent survey of six U.S. suppliers of flow monitoring equipment indicates that they would have no difficulty, using existing production facilities, in satisfying projected demand by affected units during either Phase I or Phase II.[38]

1. System Design Considerations

a. Time Period for Flow Accounting

For the same reasons described previously under SO_2 pollutant concentration monitoring, EPA has concluded that an hour is also an appropriate time period for the accounting of flue gas volumetric flow under the Acid Rain program.

b. Sampling Frequency

The general provisions of NSPS (40 CFR Part 60) specify that each component of a CEMS shall be capable of taking measurements every 15 minutes (four sampling or data points per hour) or more frequently. All three types of flow monitors currently being used to continuously monitor flue gas flow rates would satisfy this requirement. Subpart Da has no specific criteria for flow monitors.

An equivalent data capture requirement for flow would be consistent with the proposed treatment of SO_2 concentration data under the Acid Rain program, with which the flow data would be combined, and should maintain the measurement accuracy needed to ensure an accurate accounting of annual SO_2 mass emissions for comparisons against allowances held. Accordingly, EPA is proposing to require the calculation of hourly flue gas flow rate using four data points, each representing a 15-minute period, except during the hours when calibration error tests or other quality assurance activities specifically required by this Part are being performed. During these hours, only two data points are required.

2. Performance Specifications for Certification

EPA proposes to require the certification of a flow monitor before that monitor may be used to satisfy any of the continuous emission rate monitoring requirements under the proposed rule. This certification process would involve a series of tests to verify that the monitor's performance meets or exceeds EPA's minimum performance specifications with respect to: (1) relative accuracy of flow measurements, (2) absence of statistically significant bias in flow measurements, (3) calibration error or electronic stability, (4) sensitivity of flow measurements to

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[37]"Flue Gas Flow Monitoring on Electric Utility Power Plants: Technical Issues and a Suggested Technology Evaluation/ Demonstration Project," R. McRanie, April 25, 1991.

[38]"Flow Monitor Vendor Survey Results, Entropy Environmentalists, Inc., prepared for U.S. EPA, November 26, 1990.

orientation, and (5) probable lack of interference or plugging. The relative accuracy tests would be performed at three different load levels since studies of flue gas stratification[39] indicate that the cross-sectional profiles of gas velocities can vary significantly with load.[40] The calibration error test would be conducted at two flow-velocity-equivalent signals.

The proposed specifications for flow monitors are based upon the specifications in 40 CFR Part 52, Appendix E, and 40 CFR Part 60, Appendix B, but some changes have been introduced to improve the accuracy of the flow data.

Flow monitors always measure flue gas flow rate on an actual or "wet" basis. Some SO_2 pollutant concentration monitors, however, measure SO_2 concentration on a "dry" basis, where moisture is removed from the sample gas. The SO_2 concentration and flue gas flow rate measurements used to estimate SO_2 mass emissions per unit time (in lbs/hr) must be on the same moisture basis. Accordingly, units that employ "dry" SO_2 pollutant concentration monitors would correct the flue gas flow rate measurements for moisture. There are a variety of techniques available to estimate the moisture content of the flue gas, including continuous moisture monitors, pairs of "wet" and "dry" basis diluent monitors, and standard saturation/temperature tables.[41] EPA proposes that these and other moisture determination techniques would be acceptable provided they can produce hourly averages of corrected flow rate data and the corrected flow rate measurements satisfy the proposed performance specifications for relative accuracy and bias.

a. Relative Accuracy

Under the proposed rule, the performance specification tests for certifying flow monitors would be similar to those described previously for SO_2 pollutant concentration monitors.[42] The flow performance specification tests would consist of a minimum of nine sets of paired comparisons between monitor

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[39]"Flue gas stratification" is a condition where the gas velocity at any single point varies significantly from the average gas velocity by more than 10 percent. It is more difficult to measure average gas velocity accurately when flue gas stratification occurs.

[40]"Velocity Stratification," Entropy Environmentalists, Inc., prepared for U.S. EPA, February 28, 1991.

[41]Technical Letter Reports to EPA by Entropy Environmentalists, Inc., 1/11/91, and 2/4/91.

[42]See Section C on SO_2 monitoring above. Except where noted, the rationales for the various certification and quality assurance tests for flow monitoring are similar to those discussed in detail in Section C, and are not repeated in this Section.

measurements and contemporaneous reference method measurements of flue gas flow rate in cubic feet per hour at standard conditions (scfh). Reference method test results are assumed to be equivalent to the true values of the flue gas flow. EPA has defined Reference Method 2 for evaluating the accuracy of flow monitors (40 CFR Part 60, Appendix A). Reference Method 2 uses velocity traverses with an S-type pitot tube, which employs the same measurement principle as differential pressure flow monitors, to determine average flue gas velocity. As mentioned previously, the proposed rule requires affected units to perform flow monitor performance specification tests at three different loads: the minimum safe operating load, the normal load, and 90-percent of full operating capacity. In cases where the normal load is within 10 percent of either the minimum or 90-percent values, a more representative mid-range value would be chosen.

In assessing the question of the appropriate performance standard for flow monitors, EPA examined existing regulations as well as performance data on existing monitors. Appendix E of 40 CFR Part 52, promulgated in 1975, established a relative accuracy standard of 10 percent for flow monitors used in connection with federally approved State air quality implementation plans. Moreover, both EPA's review of the available literature and preliminary findings from a series of on-site flow monitor evaluations indicate that a relative accuracy standard of 10 percent or less can be achieved by well-maintained flow monitors based on current technology.[43] In particular, relative accuracy test audit data from EPA-sponsored flow monitor performance evaluations under varying loads at three test sites[44] have verified the appropriateness of the 10 percent standard. Relative accuracies of five percent or less have been achieved for some runs at high (daytime) load. Two of these test sites have flow monitors installed downstream of a wet scrubber and, as such, represent "worst case" scenarios for evaluating the accuracy of flow monitor measurements.

Concern has been raised by some electric utility representatives about the accuracy of flow monitor measurements of average flue gas velocity when flue gas stratification occurs. Bends or projections in the stack or duct may cause flow disturbances leading to flue gas stratification. EPA has sponsored a study of flow stratification in various shapes and sizes of flues to determine whether single-point, three-point, and line flow

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[43]See Figures 2 and 3 in E31, EPA Issue Paper, Flow Monitoring, prepared for the Acid Rain Advisory Committee (ARAC), April 1991.

[44]The three sites are CIPS Newton Unit #1, Big Rivers Electric Wilson Station, and Southeast Resource Recovery Facility (SERFF).

monitors[45] could be properly situated so they would obtain accurate measurements of average flue gas velocity.[46] This study indicates that, in general, properly situated flow monitors of all three types can achieve relative accuracies of 10 percent or less even when flue gas stratification occurs. An exception is the single-point flow monitor, which often cannot be situated so as to produce as consistently accurate measurements as the other monitors in either circular or rectangular flues. However, since additional evidence indicates that single-point pitot tubes can achieve this accuracy in many applications[47], the proposed rule allows the use of single-point flow monitors wherever they meet the applicable performance specifications.

Analyses of recent test data on ultrasonic and thermal flow monitors suggest that substantially better performance could be obtained with today's technology by properly calibrating the monitors to minimize instrument inaccuracy.[48] Apparently, some operators are not cognizant of (and thus, do not use) the flow monitor calibration adjustment procedures in 40 CFR Part 52, Appendix E, which could significantly improve monitor relative accuracy. EPA estimates that if these calibration procedures were regularly and properly implemented to minimize instrument bias, relative accuracies could be significantly improved beyond the 10 percent level.[49]

The foregoing discussion notwithstanding, many electric utility industry representatives remain concerned that a relative accuracy of 10 percent may not be achievable in all situations, especially at the startup of the program. As evidence of this, they have pointed to the relative accuracy values in the EPA database that are above 10 percent (none are above 15 percent). Industry representatives have also questioned the representativeness of the database for low-flow situations, which are thought to be especially problematic. Many utility representatives felt much more confident of being able to meet a standard of 15 percent, given their lack of operating experience to date. In recognition of their concern, and of the limited database to which EPA had access, the proposed rule sets the limit for

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[45]Single-point flow monitors measure at only one point in the flue gas stream, whereas three-point and line flow monitors measure at three points and more than three points, respectively.

[46]"Velocity Stratification," Entropy Environmentalists, Inc., prepared for U.S. EPA, February 28, 1991.

[47]Data from Energy and Environmental Measurements Corporation (EEMC) on single-point differential flow monitors.

[48]EPA test data from Big Rivers and SERRF test sites, April 1991.

[49]Technical correspondence from A. Wayne, May 30, 1991.

relative accuracy at 15 percent during Phase I of the acid rain program, i.e., through December 31, 1999.

Electric utility representatives also voiced concern that some retrofit situations may prove to be more difficult than those cited in the database. Particular concern was voiced that some units may not be able to meet the siting criteria in the Reference Method 1, or that duct flow characteristics may prevent the attainment of the desired accuracy. These representatives suggested that operators who undertake good faith installation and use of flow monitoring devices, which nevertheless fail to meet the required relative accuracy, not be forced into extensive, expensive studies, relocation, and/or new stack construction, but instead be allowed to adjust the data upward to account for the less accurate result. EPA expressly requests comment on this potential alternative approach.

In addition to comments on the achievable performance of flow monitors, participants in ARAC and in informal discussions recommended the adoption of a combined-system performance standard for the combined flow-SO_2 monitoring system. Such a standard reflects the precedent of Subpart Da, which requires a combined-system standard for the SO_2-diluent system as well as the NO_x-diluent system. Moreover, such a combined-system relative-accuracy standard, expressed in percentage terms, would be derived from mass units (pounds or tons of SO_2), rather than being based on flow units or concentration units, as are the component monitor standards. Since the reductions required by the Act are stated in terms of mass units, setting an accuracy requirement directly in terms of these mass units would provide more direct assurance that the primary goal of the legislation is being met. A relative accuracy of 10 percent was suggested in these discussions as the appropriate combined-system standard.

Based on the available data, analysis, and discussions, EPA proposes to phase in flow monitor relative accuracy standards. The initial standard reflects current achievement by existing monitors, and is designed to provide sources time to obtain operating experience sufficient to achieve the subsequent, more stringent standard. The requirement to meet a combined SO_2-flow system relative accuracy standard would also be phased in, for the same reasons. The flow monitor relative accuracy standard would be set at 15 percent through December 31, 1999, decreasing to 10 percent beginning on January 1, 2000, the date of the start of Phase II of the Acid Rain program. The combined-system relative accuracy standard would be set at 10 percent, becoming effective on January 1, 2000. As the deadline for implementation of the Phase II standards approaches, EPA will evaluate the experience gained under Phase I of the program and assess any potential problems of these Phase II requirements.

Today's proposal also includes provisions for obtaining exceptions to the requirements in cases where it can be demonstrated that flow monitors cannot be installed consistent with the siting criteria of Reference Method 1. It also includes a less-stringent alternative standard for low-flow situations, based

on the results of an EPA study of monitor performance.[50] The proposed alternative standard would apply to units where the average stack gas velocity during the RATA is less than or equal to 10 feet per second, and is defined as an absolute limitation on monitor inaccuracy of ±1 foot per second, as specified by procedures in Appendix A of the proposed rule.

b. Bias

As discussed previously with regard to SO_2 monitor certification, the relative accuracy statistic combines statistical descriptors of bias and precision in a manner that allows monitors with significant bias (measuring consistently low or high relative to true flow) to achieve "acceptable" relative accuracy. Accordingly, EPA is proposing that flow monitors satisfy a bias standard, in addition to the relative accuracy standard, in the performance specification tests for certification. The proposed rule requires that bias be evaluated at normal load only. In EPA's judgment, evaluation and adjustment for bias, as described below, would be too complex and unwieldy to apply at more than one load condition. Moreover, since the adjustment for bias would be applied to data at all load conditions, EPA believes that any understatement of emissions due to bias would be adequately addressed, and little would be gained by differentiating the adjustment according to load.

For the reasons discussed previously in the context of SO_2 pollutant concentration monitor certification, EPA has selected a t-test as the most satisfactory method for screening out flow monitors that measure consistently low or high relative to the reference method reading. This test, applied at the 95-percent level of confidence to detect low bias only,[51] would use the same data as that used for certifying relative accuracy at normal load. The recorded flow data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in Appendix A of the rule. Monitors failing the test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed certification bias test and the time of the next successful bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is

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[50]"Technical Guidance on Selected Flow Monitoring Procedures and Equipment: Flow Monitor Performance Evaluation, CIPS, Newton, Illinois, Volumes I and II," Entropy Corporation, 5/31/91.

[51]As previously noted, considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with alpha equal to 0.025. Thus, in Table 8-1 in Appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

Preliminary findings from EPA's on-site flow monitor evaluations suggest that this standard could be achieved by well-maintained flow monitors based on current technology, assuming they are properly calibrated using the procedures in 40 CFR Part 52, Appendix E.

c. Electronic Stability/Calibration Error

EPA proposes that a daily electronic stability test be required under the Acid Rain program for flow monitors that do not perform daily calibration error tests. The proposed procedures specify that the electronic drift of the flow monitor at 40-75 percent of span and at 80-100 percent of span not deviate from the value of the reference input signals by more than three percent. For flow monitor certification, the electronic drift would be determined once every 24 hours for seven consecutive days.

In contrast to an electronic drift test, which detects change, or "drift," over time in the electronic signals of the monitor, a calibration error test compares the monitor reading with a control standard generated by the instrument. Because not all available monitors can currently perform the more demanding calibration error test, EPA is not proposing to require this test for all flow monitors.[52] EPA is concerned that requiring the proposed daily calibration error test may be unnecessary for differential pressure flow monitors that perform automatic, timed periodic back purging, simultaneously on both sides of the probe, of sufficient force and frequency to keep the probe free of obstructions, and that provide an automatic drain for wet gases. An option to the proposed daily calibration error test for this type of flow monitor would be to perform a full-system calibration error test from the point outside the stack (or duct) where the probe enters the stack wall through the data acquisition and handling system. EPA specifically requests comment on whether this approach would be sufficient to guarantee the accuracy of the data on a daily-certifiable basis.

Even though calibration error tests are not required for all types of flow monitors in today's proposal, EPA would like to encourage all sources to perform calibration error tests where possible, and to encourage vendors to develop such tests, since they can detect problems in monitor performance regularly and promptly (i.e., within one day) and because, in EPA's judgment, they are likely to foster better maintenance. Therefore, as

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[52]Ultrasonic flow monitors can perform a daily zero-and-span check, which is in effect a 2-point calibration error test. EPA is proposing to require this test for ultrasonic monitors. Vendors of other types of flow monitors indicate they may soon develop comparable tests.

discussed in Section 3 below, EPA is proposing less-frequent relative accuracy testing frequencies for flow monitors performing daily calibration error tests. This reduced frequency is both a recognition of the reduced need for relative accuracy testing when calibration error testing is performed, and an incentive to sources to perform calibration error testing.

d. Orientation Sensitivity

EPA's flue gas stratification study and the on-site flow monitor evaluation tests, discussed above, have shown that the average flue gas velocity measurements from differential pressure and thermal flow monitors are sensitive to the monitor's orientation with respect to the axial component of flue gas flow. Specifically, misalignment of the flow monitor can produce average flue gas velocity measurements that are not representative of true flow. EPA proposes to adopt the orientation sensitivity test procedures in 40 CFR Part 52, Appendix E, for certification of flow monitors that are sensitive to the flow direction of the gas. These procedures specify that no gas velocity measurement shall deviate from the zero-degree orientation value by more than four percent.

e. Interference Checks.

Flow monitors may be susceptible to fouling or plugging of that portion of the flow monitor in contact with the flue gas. Accordingly, the proposed rule requires flow monitors to provide an automatic timed periodic back purging or equivalent method to keep the surfaces in contact with the flue gases clean and free of obstructions. The proposed rule requires an automatic drain for wet gases for self-averaging differential pressure flow monitors, and a method for detecting leaks or pluggage in differential pressure flow monitors. The proposed rule also requires all flow monitors to provide a method (a manual check is acceptable) for zeroing and calibrating the transducer. According to the flow monitor vendor survey discussed above, current U.S. suppliers of flow monitors would be able to comply with this requirement for flow monitor certification under the Acid Rain program.

3. Quality Assurance and Quality Control Procedures

The quality assurance (QA) and quality control (QC) procedures EPA is proposing for flow monitors under the Acid Rain program are similar in purpose to those discussed earlier in connection with SO_2 concentration monitors. These QA/QC procedures consist of a series of tests to be performed periodically (daily, quarterly, semi-annually, and annually) to ensure that the monitors, once certified, continue to operate reliably and accurately. In addition to the tests on the individual monitors, beginning in 2000 certain QA/QC procedures would also be performed on the combined system consisting of the SO_2 monitor and flow monitor.

Also included in the QA/QC procedures are specifications for maintaining records of QA/QC test dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA

and other applicable regulatory authorities.

a. Daily Assessments

EPA believes that it is important to the integrity of the monitoring system that any errors in flow monitor performance be identified as quickly as possible. Therefore, the proposed rule requires a daily performance check of flow monitors. The various types of flow monitors (ultrasonic, differential pressure, and thermal) use different measurement principles, and are therefore prone to different kinds of performance problems. EPA has not been able to devise a generic method for daily performance checks of flow monitors, as is proposed for SO_2 pollutant concentration monitors. Accordingly, EPA is proposing either a daily electronic stability test or a daily calibration error test for all flow monitors and other "tailored" performance checks, as appropriate.

EPA is proposing to adopt the daily zero and calibration drift requirements specified in 40 CFR Part 52, Appendix E, for daily checks of the electronic stability of all flow monitors under the Acid Rain program. These provisions require that a test to ensure that the flow monitor continues to meet the manufacturer's specifications for zero and calibration drift be performed at 24-hour intervals, or more frequently if recommended by the manufacturer. Under the proposed rule, the standard for the daily electronic stability check would be the same as that proposed for the flow monitor calibration error test (i.e., within three percent).

For ultrasonic flow monitors, EPA proposes to require daily electronic tests of both zero and span (high-level) values, analogous to the daily calibration error tests required for pollutant concentration monitors. Such daily checks are needed to validate proper operation of this flow monitor's electronically induced sound bursts for measuring gas velocity. EPA believes that these required tests are analogous to that performed by pollutant concentration monitors, and thus would qualify for reduced-frequency relative accuracy testing, as discussed in the section on quality assurance and quality control procedures.

For differential-pressure flow monitors that perform automatic, timed, periodic back purging, simultaneously on both sides of the probe, of sufficient force and frequency to keep the probe and signal lines free of obstructions, and that provide an automatic drain for wet gases, EPA proposes to require either an electronic drift test or a calibration error test. Monitors performing the latter test would qualify for reduced-frequency relative accuracy testing, as discussed in the section on quality assurance and quality control procedures. The calibration error test for these types of flow monitors would be a full system test from the probe tip through the data acquisition and handling system. However, as discussed previously in the Section on electronic stability/calibration error, EPA solicits comment on whether the proposed calibration error test for this type of flow monitor is necessary.

For thermal flow monitors, EPA proposes to require thermal

probe inspection and cleaning at a frequency that ensures the probe remains clean at all times.

The recorded flow data from a flow monitor that fails any of the required daily performance checks would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor passes the check.

b. Periodic Performance Tests

For the same reasons outlined earlier in this preamble in the section describing periodic performance tests for SO_2 concentration monitors, EPA proposes to require periodic relative accuracy test audits (RATAs) and bias tests on flow monitors. Sources that conduct daily calibration error tests on their flow monitors would perform RATA/bias tests on a semi-annual basis; others would be required to conduct RATA/bias tests on a quarterly basis. Both these frequencies could be reduced further with superior RATA performance, as outlined below.

The recorded flow data from a monitor that fails a RATA would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required relative accuracy standard. For monitors that fail a bias test, subsequent monitor measurements would be adjusted upward to compensate for bias or, at the source's option, the test could be repeated as appropriate to demonstrate that corrective measures were successful.

i. Relative Accuracy Test Audit

For those flow monitors that perform daily calibration error tests, EPA proposes to require semi-annual nine-run relative accuracy test audits (RATAs) of flow monitors for the Acid Rain program. These tests would alternate on a six-month cycle between a three-load test and a one-load test. The three-load test would be identical to the relative accuracy test described previously for monitor certification; the one-load test also would be identical to the certification test, except that it would be performed at normal load only.

For monitors that do not perform daily calibration tests, quarterly RATAs would be required. For three of the four quarters, the RATA would be run at normal load only; every fourth quarter, the test would be run at three loads, as in the certification test for relative accuracy. In EPA's judgment, this higher frequency is necessary because without daily calibration it is much more likely that relative accuracy will degrade over time. It is hoped that this dual-frequency requirement will provide sources an incentive to perform daily calibration where possible, and also induce vendors to develop applicable test methods.

Monitors would be required to attain a relative accuracy of 15 percent in Phase I of the program (i.e., through December 31, 1999), and 10 percent in Phase II (beginning January 1, 2000. In addition, in Phase II, (beginning January 1, 2000) the combined SO_2/flow monitoring system would also be required to meet a combined-system relative accuracy standard of 10 percent.

As in the case of SO_2 monitors, flow monitors achieving a relative accuracy significantly better than the standard would be allowed to decrease the RATA frequency. That is, in Phase I, flow monitors achieving a relative accuracy of 10 percent or better could reduce their RATA frequency from semi-annual to annual, or from quarterly to semi-annual for those monitors not tested daily for calibration error. In Phase II, the threshold would be lowered to 7.5 percent[53]. As long as the monitor maintained these improved relative accuracies, the reduced RATA frequency would remain in effect. Under these reduced frequencies, one test per year would be required to be a three-load test. Table 4 summarizes the required RATA frequency as a function of achieved relative accuracy.

Table 4
RATA Frequency for Flow Monitors

Relative Accuracy		Required RATA Frequency	
Phase I	Phase II	Daily Cal	No Daily Cal
≤15%	≤10%	Semi-Annual	Quarterly
≤10%	≤7.5%	Annual	Semi-Annual

ii. Bias Test

EPA proposes to require bias tests of flow monitors at normal operating load under the Acid Rain program. These tests would use the relative accuracy test audit data for normal load, would be performed at the same frequency as the relative accuracy test audits, and would be identical to the bias test described previously for monitor certification. The performance standard would be that used for certification, i.e., the data would be required to pass a t-test, applied to detect low bias only, at the 95-percent level of confidence. Data that fails the test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in Appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating

[53]Sources meeting the relative accuracy requirement (15% in Phase I, 10% in Phase II) but not achieving a relative accuracy sufficient to qualify for reduced RATA frequency (10% in Phase I, 7.5% in Phase II) would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve these superior relative accuracies and thereby lower their RATA frequency.

the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

As proposed, the bias test could be re-taken at any time at the source's option. As discussed earlier in Section C on SO_2 monitors, some have voiced concern that sources might re-run the test many times, "shopping" for a lower adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

E. NO_x Emissions Monitoring

Since the Act's limitations on NO_x emissions are expressed in terms of annual emission rate averages (in lbs/mmBtu), the monitoring requirements for NO_x emissions under the Acid Rain program will necessarily differ somewhat from those for SO_2 emissions. Specifically, the continuous monitoring of a diluent gas exhausting from the boiler, either O_2 or CO_2, would be required to convert NO_x ppmv measures from a NO_x pollutant concentration monitor into NO_x mass emission rates relative to the heat input of the fuel. The proposed rule would define a "NO_x continuous emission monitoring system" as the combination of a pollutant concentration monitor and a diluent gas monitor, as is done under Subpart Da. Therefore, annual monitor availabilities, relative accuracy and bias standards, and some other performance specifications in the proposed rule would refer to the NO_x continuous emission monitoring system, not the NO_x pollutant concentration monitor.

Analogous to the SO_2 pollutant concentration monitoring assessment, however, EPA has relied upon the historical operating experience of NO_x continuous emission monitoring systems at units subject to Subpart Da requirements to develop proposals for: (1) design of monitoring protocol, including sampling frequency and the time period for emissions accounting; (2) performance specification parameters for certifying monitoring systems, including relative accuracy, bias, calibration error, and cycle time/response time; and (3) quality assurance and quality control procedures, including daily calibration error tests and periodic relative accuracy test audits, bias tests, and calibration error tests. EPA is proposing to use the applicable provisions of Subpart Da for the NO_x emissions monitoring requirements under the Acid Rain program where they continue to define the performance achievable with current technology, provided they are consistent with the program's goals and monitoring objectives.

While the form of NO_x emissions monitoring would differ from that of SO_2 emissions monitoring under the Acid Rain program, EPA believes that the monitoring objectives are essentially the same for both acid deposition precursors. The Act's requirement "to analyze, measure, and provide on a continuous basis a permanent

record of emissions" applies to NO_x as well as SO_2. EPA believes that 100 percent accounting of NO_x emissions is required to: (1) develop viable annual NO_x emission rate averages for affected units, and (2) implement the annual NO_x emissions averaging pools allowed under the Act. Further, accurate and complete NO_x emissions data are needed from all units for the Congressionally mandated evaluation of the environmental and economic consequences of interpollutant (SO_2 for NO_x) allowance trading.

1. System Design Considerations

a. Time Period for Emissions Accounting

For the reasons discussed previously with regard to SO_2, EPA has concluded that an hour should be the basic building block in accounting for NO_x emissions under the Acid Rain program.

b. Sampling Frequency

EPA proposes to adopt Subpart Da's requirement that a continuous emissions monitoring system should be capable of taking measurements at least every 15 minutes (four sampling or data points per hour) for NO_x monitoring systems under the Acid Rain program. Subpart Da of 40 CFR Part 60, however, allows that hourly emissions data are acceptable for compliance purposes if the monitor captures at least two (out of the four) data points [60.47(a) and 60.47(b)]. The intent of this provision, as described in the NSPS Preamble (44 FR 33581, June 11, 1979), was to accommodate instruments that cannot obtain four equally spaced points during calibration periods.

Analogous to the procedure used for SO_2 and flow data, EPA is proposing to allow the calculation of average hourly NO_x emission rates (in lbs/mmBtu) using two data points, each representing a 15-minute period, of the normally required four (or more) data points during hours when maintenance, repair, calibration error tests or other quality assurance activities specifically required by this Part are being performed.

2. Performance Specifications for Certification

EPA proposes to require the certification of a NO_x continuous emission monitoring system, as is done under Subpart Da, before that monitoring system may be used to satisfy any of the emissions monitoring requirements under the proposed rule. This certification process would involve the series of tests described previously for SO_2 pollutant concentration monitors, except that most tests would be performed on the monitoring system (pollutant concentration monitor and diluent gas monitor) and test results would be on a lbs/mmBtu basis.

a. Relative Accuracy

Under the proposed rule, the performance specification tests for certifying NO_x continuous emission monitoring systems would be similar to those described previously for SO_2 pollutant concentration monitors.[54] Both SO_2 and NO_x

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[54]See Section C on SO_2 monitoring above. Except where noted, the rationales for the various certification and quality assurance tests for NO_x monitoring are similar to those discussed

performance specification tests would consist of at least nine sets of paired comparisons between monitor measurements and contemporaneous reference method measurements of pollutant emissions in the exhaust gas. Reference method test results are assumed to be equivalent to the true values of the pollutant emissions, which are unknown. EPA has defined six acceptable reference methods for evaluating the accuracy of NO_x continuous emission monitoring systems (40 CFR Part 60, Appendix A, Methods 7, 7A, 7B, 7C, 7D, and 7E). Most units subject to Subpart Da requirements currently use either Method 7 (wet chemistry) or Method 7E (instrumental).

The NO_x performance specification tests would be performed on the monitoring system (pollutant concentration monitor and diluent gas monitor) and measured in lbs/mmBtu. Unlike the SO_2 monitoring system requirements, the individual NO_x pollutant concentration monitors are not required to meet an independent relative accuracy standard of performance.

Subpart Da established a relative accuracy of 20 percent as the standard for defining acceptable NO_x monitoring system performance with respect to the accuracy of emissions measurements. EPA analysis of the relative accuracies reported by NO_x continuous emission monitoring systems at units subject to Subpart Da requirements, referenced previously, indicate that over 70 percent of these systems meet a relative accuracy standard of 10 percent. Subpart Da, however, affords low-emitting units the option of using an alternative (less stringent) standard, which is defined for NO_x as 10 percent of the applicable emissions standard (in lbs/mmBtu). As discussed previously, Subpart Da provides this optional alternative standard for low-emitting units because the mathematical construction of the relative accuracy statistic may make it more difficult for them to satisfy the normal criterion.

Because of the importance of accurate emissions measurements to NO_x annual averages, the NO_x emissions averaging pools, and other flexible components of the program, EPA is proposing a relative accuracy of 10 percent as the standard for defining acceptable NO_x continuous emission monitoring system performance under the Acid Rain program. EPA believes that this relative accuracy standard more closely reflects the performance that could be achieved by well-maintained systems based on current technology than does Subpart Da's 20-percent standard.

Like Subpart Da, EPA is also proposing a less stringent alternative standard for low-emitting units, although it is not as clear from the available data where the relative accuracy statistic becomes problematic. EPA has not completed its statistical analyses of NO_x RATA data from units subject to Subpart Da requirements. Accordingly, the proposed rule uses the cutoff established for SO_2 emission rates, or 0.5 lb/mmBtu. The optional alternative standard for low-emitting NO_x units would be defined as

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in detail in Section C, and are not repeated in this Section.