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Electricity Generation and Air Quality: Multi-Pollutant Strategies

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Summary

Fossil fuel fired electric generating facilities are major sources of air pollutants, including particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg), and of the greenhouse gas carbon dioxide (CO_2). A patchwork of regulations to limit PM, SO_2, and NOx emissions exists, with further requirements on the horizon. The piecemeal nature of the regulations and the uncertainty of future requirements impose not only direct costs on utilities, but also make planning difficult in an environment already characterized by industry restructuring, volatile energy prices, and technological changes.

To bring some consistency and stability to the regulations affecting utility emissions, legislative initiatives have proposed a "multi-pollutant" strategy. Key elements of the strategy include:

- aligning pollution control processes and procedures for PM, SO_2, and NOx so that both regulators and utility managers could anticipate requirements and integrate their decisions about how to control emissions;
- adopting efficient economic mechanisms – most notably "cap and trade" strategies – for the control of the pollutants;
- stabilizing requirements over time; and
- incorporating potential future control requirements for other emitted gases (e.g., Hg, CO_2) into this more stable scheme.

This approach to controlling powerplant emissions would have several tradeoffs. Overall, it exchanges regulatory and economic uncertainty for short to mid-term certainty. For the environment, the current controversy that accompanies the setting of standards and the implementing of regulatory reduction requirements would be exchanged for a specific reduction target that would not change for 10-15 years. From an economic standpoint, implementing emission caps through emission trading would reduce costs, and the straightforward enforcement mechanism would also provide industry with certainty with respect to their responsibilities and potential penalties, and allow industry to plan for the future in the context of a consistent regulatory regime. Finally, the program might open the door for simplifying or replacing elements of the current piecemeal requirements. However, cap and trade systems could conflict with health standards to protect local areas from "hot spot" emissions.

Although the Clean Air Act's evolution has resulted in a structure that some characterize as unwieldy, the number of persons living in areas where air pollution exceeds standards has diminished. Arguably, the Act's success puts the burden of proof concerning amendment on those favoring change. Amending the Act has always proved contentious; but for many, the opportunities for greater predictability of requirements, fixed emission reductions, and cost efficiency are enticing.

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Introduction

Beginning with the Clean Air Act of 1970, and with substantive additional measures enacted in amendments of 1977 and 1990, electric utilities have been subjected to a multilayered patchwork of air pollution emission requirements. Fossil fuel fired electric generating facilities are major emitters of gases (see table 1), with clean air controls currently directed at three pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulates (PM). Sulfur oxides have health effects and are a major contributor to acid rain and visibility impairment. Nitrogen oxides have direct health effects, contribute to acid rain and visibility impairment, and are a precursor to ozone, a primary constituent of smog. Particulates have health effects, with the smallest particles now thought to be the most serious causative agents; current regulations focus on particles 10 microns in size or smaller (PM_{10}) and new regulations would control particles less than 2.5 microns in diameter ($PM_{2.5}$). Emissions of SO_2 and of NOx contribute to the formation of these very fine particles. In 1998, electric utilities accounted for approximately 67% of U.S. emissions of SO_2, 25% of NOx, and 11% of PM_{10}.

The evolution of air pollution controls over time and as a result of developing scientific understanding of health and environmental impacts has led to the multilayered and interlocking patchwork of controls, which are outlined in more detail below. Moreover, additional controls are in the process of development, in particular with respect to NOx as a precursor to ozone, and to both NOx and SO_2 as contributors to $PM_{2.5}$.

In addition, fossil fuel fired electric generating facilities produce two other gases of environmental and health concern: mercury (Hg) and carbon dioxide (CO_2). While some sources of mercury are currently regulated, emissions from electric utilities are not. However the Clean Air Act Amendments of 1990 designated Hg as a hazardous air pollutant subject to a regulatory regime spelled out in §112. EPA was also required to study hazards to public health from hazardous air pollutant emissions of electric utility steam generating units in general; and, separately, to report to Congress on mercury emissions from major sources, including electric utility steam generating units. This study, completed in 1997, concluded mercury is a hazard to public health; and it found that electric utility steam generating units account for about one-third of the nation's mercury emissions.[1] On December 14, 2000, EPA

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[1]U.S. Environmental Protection Agency, *Mercury Study Report*, EPA-452/R-97-003, December 1997.

announced its intention to regulate utility Hg emissions in 2004, with an effective date of 2007 or 2008.[2]

Carbon dioxide is a major greenhouse gas, and fossil fuel fired electric generating facilities account for about 36% of U.S. emissions. While CO_2 emissions are not currently regulated, the United States is a signatory of the United Nation Framework Convention on Climate Change, which involves a voluntary commitment to hold greenhouse gas emissions to 1990 levels. At present, U.S. emissions of CO_2 are running some 10% over that goal.[3] Further, the U.S. has signed the Kyoto Protocol, under which the U.S. would be legally committed to reduce emissions in the 2008-2012 period by 7% from a baseline that includes 1990 CO_2 levels; however, that Protocol has not yet been submitted to the Senate for advice and consent and is not in force. But it remains possible that, beyond the already existing voluntary goal, utilities will be subjected to emissions limits on CO_2 at some time in the future.[4]

As described below, this patchwork of existing and potential emissions requirements applicable to fossil fuel fired electric generating facilities has a direct impact on strategic decisions concerning investment in new facilities as well as operational decisions with respect to the timing of maintenance and scheduling of operation. At the same time, the electric utility industry is undergoing major restructuring changes. Proponents of change argue that the air quality requirements add confusion and uncertainty to a utility decisionmaking environment already challenged by new generating technology and new policies concerning competition and economic regulation.

A restructured electricity generating sector may have consequences for emissions: current electricity generating economics favor the continued operation of older, more polluting coal-fired facilities, at the expense of building newer, cleaner, natural gas-fired facilities. Previous CRS analysis suggests that the environmental effects of restructuring depend on how well the existing regulatory regimen will work as the industry structure changes.[5] It appears that pollutants controlled under emissions caps, such as SO_2 under the acid rain title of the 1990 CAA Amendments, would retain their efficacy regardless of the industry's structure. The robustness of emissions caps and the possible cost savings that tradeable emissions credits provide are seen by some as a better fit for a restructured industry than the current regulatory system.

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[2]EPA, "Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units," *Federal Register*, Vol. 65, no. 245 (December 20, 2000), 79825-79831.

[3]John E. Blodgett and Larry Parker, *Global Climate Changes: Reducing Greenhouse Gases–How Much from What Baseline?* CRS Report 98-235 ENR. Updated Jan. 29, 2001.

[4] For a review of U.S. global climate change policy, see: Larry Parker and John Blodgett, *Global Climate Change Policy: From "No Regrets" to S. Res. 98,* CRS Report RL30024, January 12. 1999.

[5]Larry Parker and John Blodgett, *Electricity Restructuring: The Implications for Air Quality*, CRS Report 98-615, updated January 4, 2001.

Table 1: National Estimated Emissions from Fossil-Fuel, Steam-Electric Utilities — 1998

	CO_2		NOx		PM_{10}		SO_2		Hg	
	1000 short tons	% all sources	1000 short tons	% all sources	1000 short tons	% all sources	1000 short tons	% all sources	tons	% all sources
Electric Utilities	2,209,287	36	6,103	25	302	11	13,217	67	43	~33
Coal	1,911,627		5,395		273		12,426			
Oil	100,895		208		9		730			
Gas	195,868		344		1		2			
Other/Internal Combustion	897		156		19		60			

Sources: CO_2 — DOE, Energy Information Administration, *Electric Power Annual 1998*, Vol. II, p. 42; NOx, PM_{10}, SO_2 — EPA, *National Air Quality and Emissions Trends Report, 1998* EPA 454/R-00-003 (March 2000), Tables A-4, A-6, and A-8 [http://www.epa.gov/oar/aqtrnd98/fr_table.html]; Hg —"EPA Determination on Mercury Emissions from Electric-Steam Generating Units," text in *Environment Reporter*, Vol. 31, no. 50 (December 15, 2000), 2677-83.

For many years the complexity of the air quality control regime has caused some observers to call for a simplified approach. Now, with the potential both for additional control programs on SO_2 and NOx and for new controls directed at Hg and CO_2 intersecting with the technological and policy changes affecting the electric utility industry, such observers have become more numerous and are pushing more strongly for a simplified approach.

Several simplifying approaches have been proposed, ranging from repeal of various components of the air pollution regulatory system, to comprehensive replacement of the "command and control" regulatory approach with some economic mechanism, which is often touted as more efficient and transparent. In the mid-1990s, EPA began investigating the merits of a comprehensive approach to utility emissions control. Called the "Clean Air Power Initiative," the purpose was "to develop, in consultation with stakeholders, an integrated regulatory strategy for pollutants emitted from electric powerplants: sulfur dioxide, nitrogen oxides, and, potentially, mercury." It was "a collaborative effort to seek new approaches to future pollution control that cost less, rely on market mechanisms, and reduce the number and complexity of requirements ...."[6]

As the effort evolved, a "multi-pollutant"or "four pollutants" approach has come to the fore. This approach involves a mix of regulatory and economic mechanisms that would apply to utility emissions of up to four pollutants – SO_2, NOx, Hg, and CO_2. The objective would be to balance the environmental goal of effective controls across these pollutants with the industry goal of a stable regulatory regime for a period of years.

During the 106th Congress, ten bills were introduced to increase pollution controls on electric generating facilities.[7] The pollutants targeted under these bills included SO_2, NOx, Hg, and CO_2. All of these bills involved some form of emissions caps, and most included a tradeable credit program to implement that cap. With President Bush endorsing a four pollutant emissions cap with tradeable permits program during the campaign, attempts to address the issue are possible in the 107th Congress.[8]

This report proceeds by (1) laying out the existing regulatory framework, with emphasis on how it can affect strategic and operational decisions in the utility industry; (2) identifying the "drivers" for rethinking the way air pollution controls are imposed on the industry; (3) describing the elements of a "four pollutants" approach; and (4) discussing the ways that this approach would affect the control of emissions and the industry's decisonmaking. It concludes with a brief outline of legislative options for achieving the goal of balancing environmental and industry objectives.

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[6]"EPA's Clean Air Power Initiative (CAPI), October 22, 1996, at [http://www.epa.gov/capi/capifs3.htm]

[7]Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326, updated July 26, 2000.

[8]George W. Bush for President, *Energy: Propose Legislation that Will Require Utilities to Reduce Emissions and Significantly Improve Air Quality*, George W. Bush for President Official Site: Issues, 2000.

The Regulatory Framework: Utility Air Quality Regulation

To understand the interest in an integrated approach to controlling utilities emissions of air pollutants, it is necessary to recognize the diverse requirements imposed by the CAA. Within the general regulatory structure, several distinctions arise that affect utility planning and operations – e.g., whether the facility is located in clean or dirty air areas, whether a facility is existing or new, and what fuel it burns. And while the underlying regulatory structure generally applies to SO_2, NOx, and PM, the specific requirements for each differ.

National Ambient Air Quality Standards – New Source Performance Standards – Lowest Achievable Emissions Rate. As enacted in 1970, the CAA established a two-pronged approach to protect and enhance the quality of the nation's air. First, the Act established National Ambient Air Quality Standards (NAAQS), which set limits on the level of specified air pollutants in ambient air. Second, the Act required national emission limits to be set for major new polluting facilities; these are called New Source Performance Standards (NSPS).

NAAQS have been established for six pollutants, including SO_2, NOx, and PM. Under the law, EPA sets primary NAAQS[9] to protect the public health with an "adequate margin of safety."[10] EPA periodically reviews NAAQS to take into account the most recent health data. NAAQS are federally enforceable with specific deadlines for compliance, but states are primarily responsible for actually implementing the standards, through development and enforcement of State Implementation Plans (SIPs). In general, these plans focus on reducing emissions from existing facilities to the extent necessary to ensure that ambient levels of pollution do not exceed the NAAQS.

For areas *not* in attainment with one or more of these NAAQS, the 1970 CAA mandates states to require new sources to install Lowest Achievable Emissions Rate (LAER) technology. Along with offset rules, LAER ensures that overall emissions do not increase as a result of a new plant's operation. LAER is based on the most stringent emission rate of any state implementation plan or achieved in practice without regard to cost or energy use.[11] Existing sources in a non-attainment area are required to install Reasonably Available Control Technology (RACT), a state determination based on federal guidelines.

The 1970 CAA also established New Source Performance Standards (NSPS), which are emission limitations imposed on designated categories of major new (or substantially modified) stationary sources of air pollution. For fossil fuel fired

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[9]"Secondary" NAAQS, also nationwide standards, protect "welfare" values, such as visibility and agricultural productivity. There is no specific deadline for achieving secondary NAAQS.

[10]For a further discussion of NAAQS standard-setting, see: John Blodgett, Larry Parker, and James McCarthy, *Air Quality Standards: The Decisionmaking Process,* CRS Report 97-722 ENR.

[11] LAER may not be less stringent than NSPS, described below.

electric generating facilities, EPA has set NSPS for SO_2, NOx, and PM_{10}, and is required by the Act to review the standards every eight years. A new source is subject to NSPS regardless of its location or ambient air conditions.

In summary, under this overall regulatory regimen, existing sources in non-attainment areas are subject to controls determined by the state as necessary to meet NAAQS; existing sources are essentially free from controls in attainment areas. And major new sources, including fossil fuel fired electric generating facilities, are subject to NSPS as the minimum requirement, anywhere.[12]

Prevention of Significant Deterioration – New Source Review – Best Available Control Technology. The 1977 CAA broadened the air quality control regimen with the addition of the Prevention of Significant Deterioration (PSD) and visibility impairment provisions. The PSD program (Part C of the CAA) focuses on ambient concentrations of SO_2, NOx, and PM in "clean" air areas of the country (i.e., areas where air quality is better than the NAAQS). The provision allows some increase in clean areas' pollution concentrations depending on their classification. In general, historic or recreation areas (e.g., national parks) are classified class 1 with very little degradation allowed while most other areas are classified class 2 with moderate degradation allowed. States are allowed to reclassify Class 2 areas to Class 3 areas, which would be permitted to degrade up to the NAAQS.[13] New sources in PSD areas must undergo preconstruction review (called New Source Review or NSR) and must install Best Available Control Technology (BACT) as the minimum level of control. State permitting agencies determine BACT on a case-by-case basis, taking into account energy, environmental and economic impacts. BACT cannot be less stringent than the federal NSPS, but it can be more so. More stringent controls can be required if modeling indicates that BACT is insufficient to avoid violating PSD emission limitations, or the NAAQS itself.

A complement to the PSD program for existing sources is the regional haze program (section 169A) that focuses on "prevention of any future, and the remedying of any existing, impairment of visibility" resulting from manmade air pollution in national parks and wilderness areas.[14] Among the pollutants that impair visibility are sulfates, organic matter, and nitrates. Existing sources are required to install Best Available Retrofit Technology (BART). In 1999, the EPA promulgated a regional haze program, which would entail more stringent controls on NOx and SO_2.

With a comprehensively regulated electric utility industry, the above regime resulted in significant reductions in pollutant emissions, particularly from new

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[12] The federal focus on new facilities arose from several factors. First, it is generally less expensive to design into new construction necessary control features than to retrofit those features on existing facilities not designed to incorporate them. Second, uniform standards for new construction ensures that individual states will not be tempted to slacken environmental control requirements to compete for new industry.

[13] None have been reclassified to Class 3, however.

[14] See James McCarthy, et al., *Regional Haze: EPA's Proposal to Improve Visibility in National Parks and Wilderness Areas*, CRS Report 97-1010, updated July 9, 1998.

sources. However, environmental and economic factors have evolved over the past thirty years that expose cracks and discontinuities in the regime. Environmentally, it became increasingly clear that ecological effects were occurring at pollutant levels below those necessary to protect human health. The classic example is acid rain, in which total pollutant loadings are more important that ambient concentrations. Economically, the requirements on new sources were proving to be a strong incentive for the "life extension" of older, existing facilities that could operate more inexpensively but which were emitting pollutants at higher rates than new facilities.[15]

Acid Rain – Statutory SO_2 Cap and Allowance Trading System. To address acid rain, title IV of the 1990 CAAA established a new control regime essentially independent of the NAAQS-NSPS processes. Instead of the NAAQS-based focus on acceptable ambient concentrations of a pollutant enforced on a plant-by-plant basis, title IV establishes a cap and trade scheme that limits SO_2 (the primary precursor of acid rain) emissions more stringently than NAAQS levels. (Although total emissions, not ambient concentrations, become the focus of reductions, concentrations are still limited by NAAQS, so "hot spots" are prevented). Such an approach is appropriate where regional, national, or global loadings of a pollutant reaches critical levels despite acceptable localized effects. The ability to trade emission rights increases the economic efficiency of the system and, assuming rigorous monitoring, simplifies enforcement.

Title IV also required reductions in NOx emissions. However, in contrast the SO_2 cap and trade program, the NOx program set performance standards based on low-NOx burner technology on a boiler-specific basis for facilities affected by the SO_2 requirements.

Statutorily, then, the air quality control requirements imposed on fossil fuel fired electric generating facilities can be summarized as shown in table 2.

Pending and Prospective Utility Air Quality Controls

The preceding section outlined the air quality controls that have directly affected fossil fuel fired electric generating facilities. Continuing developments in understanding of the effects of different pollutants, especially of SO_2 and NOx, both individually and in combination, are heightening concerns about the adequacy of existing controls. Issues include continuing difficulties in meeting the ozone NAAQS, health effects of fine particulates, impaired visibility, and global warming. These concerns are driving new initiatives to increase controls at existing sources of these pollutants. As a result, more air quality controls on utilities are pending or prospective. At the same time, the increasingly complex and interactive structure of the air quality control regime is raising questions about the effectiveness and economic efficiency of the individual initiatives.

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[15] See Larry Parker and John Blodgett, *Electricity Restructuring: The Implications for Air Quality*, CRS Report 98-615 ENR, updated January 4, 2001.

Table 2: Simplified Summary of Air Quality Control Requirements for Electric Generating Facilities

<table>
<tr><th></th><th>Attainment Area</th><th>Nonattainment Area</th></tr>
<tr><td rowspan="2">New Source</td><td>NSPS (PM_{10}, SO_2, NOx).

PSD-BACT, as determined by individual states; can not be less stringent than federal NSPS. Increment rules also apply.</td><td>NAAQS-LAER as determined by individual states; can not be less stringent than the federal NSPS. Offset rules also apply.</td></tr>
<tr><td colspan="2">Acid Rain – offsets for all SO_2 emissions must be obtained through the allowance trading system.</td></tr>
<tr><td rowspan="2">Existing Source</td><td>No general federal requirements, except: BART required in areas affected by visibility provisions.</td><td>NAAQS-RACT as determined by individual states under federal guidelines.</td></tr>
<tr><td colspan="2">Acid Rain – SO_2 emission limits specified for facilities over 25 Mw; allowable emissions maybe traded or banked through an allowance trading system. Title IV provisions include NOx emissions limits.</td></tr>
</table>

Health and Environmental Concerns Driving New Air Quality Initiatives. Achieving the NAAQS for certain pollutants (particularly ozone), has called for new control regimes. EPA's NOx SIP Call is an example of one such approach.[16] Under the SIP Call, the affected states are given emission budgets that they can achieve in whatever manner they choose. Noting the regional nature of the ozone problem in the eastern U.S., EPA is strongly encouraging states to implement the rule through a cap and trade program. As the ozone problem is seasonal, the controls are only for the summer months. This seasonal requirement may be adequate for meeting the ozone NAAQS, but may not fall short in addressing other environmental concerns (fine particulates and visibility, for example). Moreover, this ozone control regime is based on EPA regulation, whereas the acid rain control regime is statutory. As a result, the ozone requirements are subject to some uncertainty, in particular the potential cap and trade provisions for NOx which would be implemented by states individually.

[16]For further information on the NOx SIP Call, see: Larry Parker and John Blodgett, *Air Quality: EPA's Ozone Transport Rule, OTAG, and Section 126 Petitions – A Hazy Situation?* CRS Report 98-236 ENR. For recent activities, see: Larry Parker and John Blodgett, *Air Quality and Electricity: Initiatives to Increase Pollution Control*, CRS Report RS20553.

Along with the pending NOx controls resulting from the continuing difficulties in meeting the ozone NAAQS, concern has been growing about the health and/or environmental impacts of mercury and greenhouse gases.

Under the 1990 CAAA, mercury was listed as a toxic air pollutant under Section 112. This requires EPA to set standards for sources of Hg that achieve "the maximum degree of reduction in emissions" taking into account cost and other non-air-quality factors. These Maximum Achievable Control Technology (MACT) requirements for new sources "shall not be less stringent than the most stringent emissions level that is achieved in practice by the best controlled similar source." The standards for existing sources may be less stringent than those for new sources, but must be no less stringent than the emission limitations achieved by the best performing 12% of existing sources (if there are more than 30 such sources in the category or subcategory).

As previously noted, EPA stated on December 14, 2000 that it would be regulating utility emissions of Hg. However, the exact form those regulations will take remains to be seen.

The possibility of carbon dioxide emission controls is less clear. No federal policy currently imposes a control program on CO_2 emissions, but global climate change concerns seem to be growing. If such a policy were to be adopted, utilities would be among the most affected sectors. The prospect of controls is underlined by a provision of the CAAA of 1990 (§ 821), which requires the monitoring of greenhouse gases, and a provision of the 1992 Energy Policy Act (§ 1605(b)), which provides a mechanism for reporting voluntary reductions in greenhouse gases. Electricity projects account for half the voluntary reductions that have been reported under § 1605(b).[17]

These several concerns – emissions of SO_2 and NOx, ozone nonattainment and fine particulates, and mercury and global warming – introduce uncertainty and the prospect of new layers of air pollution controls. As major sources of emissions of these pollutants, fossil fuel fired electric generating facilities thus have a particular interest in the outcome of these initiatives, which are summarized in table 3.

[17]*The Greenhouse Gas Volunteer*, Vol. 6, no. 3 (Dec. 2000).

Table 3: Pending and Potential Controls on Existing Sources

Pollutant	Potential Controls on Existing Sources
Nitrogen Oxides	Title IV, sec. 407 Ozone Transport Commission (OTC) Rules Ozone Transport Rule Section 126 Petitions Revised Ozone NAAQS Fine Particulate NAAQS New Source Review Enforcement Regional Haze Rule More stringent Legislation[a]
Sulfur Oxides	Title IV Fine Particulate NAAQS New Source Review Enforcement Regional Haze Rule More stringent Legislation[a]
Mercury	EPA regulation as a HAP NE Action Plan on Mercury Potential Legislation[a]
Carbon Dioxide	U.N. Framework Convention on Climate Change Potential ratification of Kyoto Agreement Potential Legislation[a]

[a] For information on legislative proposals relating restructuring to environmental controls, see Larry Parker and Amy Abel, *Electricity: The Road Toward Restructuring*, CRS Issue Brief IB10006; for information on legislation that was proposed in the 106th Congress, see Larry Parker, *Electricity Restructuring: Comparison of Comprehensive Bills*, CRS Report RL30087 and Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326, updated July 26, 2000.

Economic and Regulatory Drivers Affecting Perspectives on Air Quality Controls. The control measures needed to address these environmental concerns have emphasized the basic economic decisions made in 1970. First, the 1970 CAAA created an economic bias in the system because existing sources can often achieve compliance with its provisions at less cost than new sources. It was perceived to be more economically efficient to require the most stringent control on new sources while giving states discretion through the SIP process to require existing sources to retrofit controls only when, and to the extent, necessary. This situation was not changed by the addition of market mechanisms in the 1990 CAAA. Under the acid rain provisions, existing sources were allocated credits based on a reduction requirement less stringent than the current NSPS, while new sources were allocated no credits at all. This disadvantage may not have been particularly significant during a time when electric utilities were comprehensively regulated and new sources were needed to meet increased electric demand. However, in the emerging competitive electric supply market, the bias arguably discriminates against new entrants as existing suppliers have the advantage of less stringent control requirements and a pool of free emission credits.

Economic bias has also been created on a regional basis. For example, under the 1990 CAAA, an Ozone Transport Region was created among 12 northeastern states (and the District of Columbia). In this region, it is virtually impossible for an individual state to achieve the ozone NAAQS because of interstate movement of air masses. Among the control mechanisms to reduce the region's ozone load, these states have instituted significant NOx controls not required in neighboring states, and 11 of the states (and the District of Columbia) have joined in a regional NOx trading system. These regional ozone controls impose costs not borne by other states.

Second, the mixture of control requirements, standards, and market mechanisms has complicated corporate planning with respect to renovating existing capacity and building new capacity. Uncertainty with respect to planning is increasing with the possibility of new pollutants being added (e.g., carbon dioxide and mercury), and with potentially conflicting control regimes for existing pollutants. For example, EPA's NOx SIP Call requiring pollution controls in the eastern U.S. is based on ozone concerns. Therefore, the controls are only in place for the season of the year that ozone is a problem (i.e., May-September). However, potential fine particulate NAAQS implementation strategies would involve year-round NOx controls. Compliance strategies that might be optimal for a seasonal program might not be the strategies of choice under a year-round control regime. Thus, a utility may find itself having to make an expensive mid-course correction, or living with a sub-optimal compliance scheme, because of changing regulatory requirements.

Third, the market forces unleashed by electricity restructuring are providing impetus to companies' desires for flexibility in complying with environmental standards, and for what they see as a level playing field between competitors. Producers of newer "clean electricity" wants their competitors to meet the same or equivalent standards that they have had to meet. All producers want more certainty in terms of the standards they are likely to see imposed in the near to mid term.

Alternative: The Four Pollutant Strategies

With the prospect of new layers of complexity being added to air pollution controls and with electricity restructuring putting a premium on economic efficiency, it is not surprising that interest in finding mechanisms to achieve these new health and environmental goals in simpler, more cost-effective ways has been on the rise. Taking the acid rain program – widely viewed as highly successful both in controlling emissions and in economic efficiency – as a model, the proposed "multi-pollutant" approach would establish a consistent framework of emissions caps, implemented through emissions trading. Just how the proposed approach would fit with the current (and proposed) diverse regulatory regimes remains to be worked out; they might be replaced to the greatest extent feasible, or they might be overlaid by the framework of emissions caps. The key assumption of this approach is that the current process of addressing pollution problems on a sequential, pollutant-by-pollutant basis can be superceded with a coordinated and integrated national program that would stabilize requirements for a number of years.

Such an approach to powerplant emissions would have several tradeoffs. Overall, the primary tradeoff is exchanging regulatory and economic uncertainty for short to mid-term certainty.

The environmental advantage of this approach is the probability that emission reductions would occur earlier than under the current regulatory process. If the current acid rain program is any indication, a legislated cap and trade program could result in earlier emission reductions than the current, often adversarial regulatory process. Challenges to the system, and resulting delays, might be reduced under a cap and trade system. The potential environmental disadvantage would be that any reduction target agreed to might be frozen for a specific period of time. Arguably, however, it could be easier (administratively or statutorily) to reduce an emissions cap in the future after the agreed upon time has expired than to develop a new, potentially overlapping regulatory scheme as would be currently the case. For example, many proposals to further reduce SO_2 emissions simply call for a reduction in the current title IV cap, rather than the development of new control structures.

Economic analysis projects that implementing emission caps through emission trading would reduce costs by a significant amount, although the actual savings that might be realized is debatable. For industry, a cap and trade system could not only save costs directly, but would likely reduce uncertainties with respect to utility responsibilities and potential penalties, thus allowing the industry to plan for the future in the context of a more coherent regulatory regime. Finally, a flexible cap and trade program might open the door for reforming or replacing the current, sometimes burdensome, NSR/PSD permitting process. Specifically, the cap and trade programs might be coupled with a streamlined permitting process along the line of the Title V permit program.

A disadvantage of emissions caps would be the possibility that unnecessary emission reductions could be required. Emission caps could overshoot the mark, resulting in unnecessary costs.[18] Also, the certainty of reductions could also result in costs being incurred earlier than would be the case under the current system. Finally, most proposals for a cap and trade system do not eliminate the requirement to protect local air quality, so mechanisms to ensure NAAQS would not be exceeded locally – such as some sort of trading restrictions – might be imposed.[19]

Specific Pollutant Issues

Although the four pollutant approach calls for a coordinated cap and trade system to supplement, and, in some cases, replace the existing structure, the resulting caps would not necessarily be the same. Each pollutant presents unique issues with

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[18]However, the CAA assumes that achieving levels of air quality cleaner than NAAQS is intrinsically good, as it provides a greater margin of safety, leaves more room for future development, and discourages sources from "shopping" for clean air areas to pollute.

[19]Such constraints exist in existing trading situations: see Barry D. Solomon and Russell Lee, "Emissions Trading Systems and Environmental Justice," *Environment*, Vol 42, no. 8 (October 2000), p. 41.

respect to baselines, allocation schemes, reduction targets, and compliance measures.

Sulfur Dioxide. Utility emissions of sulfur dioxide are the only pollutant of the four identified here that is currently controlled with a cap-and-trade system. Specifically targeting acid rain concerns, this cap and trade system is laid on top of a number of regulatory schemes (as illustrated in Table 1A in the appendix). When enacting the title IV acid rain provisions, Congress did not remove any existing provisions with respect to utility SO_2 emissions, except for an ambiguous repeal of the percent reduction requirement (ambiguous in that the repeal prohibits any backsliding). Thus, in one sense, title IV is little more than another patch in the current patchwork that constitutes current air policy.

However, in terms of mechanics, the SO_2 program provides a working example of how a system employing emission caps and trades can operate successfully. By just about any criterion – economic, environmental, implementation – the program has met or exceeded its goals. Economically, the SO_2 program is costing about $1 billion annually. This is substantially below EPA's costs estimates in 1990 of $2-$4 billion annually, and an order of magnitude lower than the $10 billion annual cost estimate provided by the utility industry. Environmentally, reductions achieved from 1995-1999 have exceeded the mandated target by between 23% (1997) and 40% (1995).[20] In terms of implementation, compliance with the program has been 100%, with no delays in implementation of the SO_2 program.

Thus the current SO_2 program might be seen as a good model for developing a coordinated policy for more stringent control of utility air emissions – both of SO_2 and potentially of other pollutants. The model includes an established baseline (1990 emissions) with a credible inventory and continuous monitoring system. The trading mechanics, including the automatic tracking system, outside brokers, and banking, are well established and functioning efficiently. The permitting, monitoring, and enforcement provisions are well-understood. In theory, to more stringently control SO_2 the overall cap and individual allowance values would simply need to be reduced by an agreed upon percentage.

It is possible that more stringent control could expose difficulties with the current system that have not shown up. For example, a more stringent program would increase the value of allowances and make issues of economic bias more transparent, both regionally and between competitors. The allocation system for the 1990 CAAA title IV program was a hard-fought compromise. It was also arrived at during a time when non-utility emissions were minor. Schemes designed to protect new competitors have proven unnecessary, as allowance prices have remained low. Higher valued allowances could change all that. Under the current system, newly constructed power plants receive no allocation of allowances; instead, new sources must obtain any necessary allowances from owners of existing facilities on the open market or through the EPA-sponsored auction. In either case, a more stringent cap would make this process more expensive.

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[20] U.S. Environmental Protection Agency, *Acid Rain Program: 1999 Compliance Report*, EPA-430-R-00-007, July, 2000. p. 22.

Opening the allowance allocation scheme to revision could involve a protracted debate between the different interest groups. Both baseline issues and distribution issues would be involved. The current system provides free allocation of allowances to existing facilities based on a 1985-87 database and a legislated emissions rate. Alternatives range from a new source pool of free allowances to wholesale auctions to allocate all allowances. Any decision made with respect to SO_2 allowances could spill over into any NOx, Hg, or CO_2 allocation scheme.

Nitrogen Oxides. NOx illustrates many of the concerns driving the current interest in a four pollutant strategy. As indicated in Table 2A in the appendix, the multiple effects resulting from NOx emissions have led to their control under several different parts of the CAA. Nitrogen oxides, both directly and because they contribute to formation of ozone, raise human health and environmental concerns that bring them under the purview of the CAA. In addition, nitrogen oxides are precursors of fine particulates, which are suspected of significant human mortality and morbidity effects. Environmental concerns about NOx emissions include its transformation into nitric acid, a component of acid precipitation; visibility impairment; and known effects of ozone on plant life.[21] In addition, EPA estimates that up to 40% of the nitrogen "loading" in the Chesapeake Bay, resulting in excessive nutrient enrichment, is the result of deposition of air-borne nitrogen oxides.

For proponents of a four pollutant strategy, this discovery of one effect after another for NOx, resulting in one regulation after another, illustrates the need for a more stable and coherent regime. However, each component of the existing structure has emerged from a set of negotiations and compromises; imposing a new structure could likely disrupt agreed-upon outcomes, and keeping all stakeholders whole would be very difficult.

Under title IV of the 1990 CAAA, a continuous monitoring network has been set up to measure NOx emissions at the stack. Thus, inventories and monitoring of NOx emissions are not problems in developing a NOx cap and trade program. There is also some experience in trading NOx credits, thanks to the Ozone Transport Commission's trading regime for the eleven northeastern states (plus D.C.). Experience there suggest a more volatile market than for the larger 48 state SO_2 market. Interest in the market has spawned outside brokers to facilitate trades in the Northeast.

However, the regional nature of current NOx markets may present problems for a national cap and trade program. This situation will not necessarily be improved by implementation of EPA's Ozone Transport Rule (NOx SIP Call). Under the SIP process, EPA does not have the authority to require that individual states employ compatible cap and trade systems to implement the rule; or even to use a cap and trade program at all. EPA has provided guidance through a model cap and trade

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[21] For a discussion of ozone and acid precipitation effects on vegetation, see Shriner, David S., et. al. *Response of Vegetation to Atmospheric Deposition and Air Pollution: State of Science and Technology Report 18*. Washington, D.C.: National Acid Precipitation Assessment Program, December 1990.

program. And it has proposed Federal Implementation Plan (FIP)[22] requirements as to what kind of cap and trade program it would feel appropriate to implement the rule. However, states are free to ignore EPA's model rule, and comply with the NOx SIP Call in any fashion they believe appropriate to their state's conditions.

Besides this lack of uniformity, existing and potential future NOx regulatory regimes create other difficulties. Some of these difficulties resemble those surrounding SO_2 regulation. Developing an acceptable allocation scheme would be at least as difficult as it was for the SO_2 Title IV program. Indeed, it may be more contentious because NOx allowances would potentially be more expensive to buy than SO_2 allowances. Over the past year, SO_2 per ton allowances have run in the range of $150 or less. In contrast, NOx allowances under the OTC program has fluctuated between $500 and $1000 each. A larger market might reduce the price instability in the current OTC market, but the clearing price is still likely to be higher than the current SO_2 price. This situation might be of particular concern to new competitors in the generation market who would object to any allocation scheme that grandfathered existing facilities at their expense – i.e., that allocated free allowances to existing facilities but not to future ones.

However, other difficulties are unique to the development of NOx regulation. A major problem is the current focus on NOx as precursor to ozone, which results in it being treated as a regional, not national problem. Efforts to control NOx have concentrated on the northeast and California, where the ozone problem is most acute. EPA's NOx SIP Call covers only the eastern 21 states and D.C. Likewise, because ozone is a summer pollutant, a second major problem is that controls are only required during the summer season (May-September), not year-round. With other environmental concerns, such as fine particulates and visibility calling for year-round controls, confusion with respect to appropriate control strategies is common. Would a new regime have any obligation to provide a transitional period to polluters who in good faith installed seasonal controls, only to have the rules changed by further regulation?

Laying a national four-pollutant strategy over these individual programs is problematic. The Northeast has a working cap and trade program for the summer months. Much of the rest of the East would be incorporated into a summer program under the NOx SIP Call, which may or may not include cap and trade. California has its own control program with NOx credits. Much of the rest of the country only has special NOx controls as required by the low-NOx burner requirement of title IV. How could these diverse elements be integrated into a national cap and trade program? The development of an allocation scheme that deals equitably with these elements within acceptable time frames would be a tremendous challenge.

Mercury. While not currently regulated, utility emissions of Hg are prospective. While SO_2, PM, and NOx are regulated under the NAAQS process, Hg

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[22]The CAA provides that EPA ultimately impose a FIP in any state which fails to implement an adequate SIP. For details on the proposed NOx FIP, see Larry Parker and John Blodgett, *Air Quality: EPA's Ozone Transport Rule, OTAG, and Section 126 Petition – A Hazy Situation?* CRS Report 98-236 ENR, pp. 14-16.

would be regulated as a toxic air pollutant under the hazardous air pollutants section of the CAA (§ 112), which would require maximum achievable control technology (MACT). Moreover, Hg regulation would be starting from a more rudimentary position than regulation of SO_2, PM, and NOx.

Despite these challenges, EPA has stated it will be regulating Hg in the next few years; thus its inclusion in a four-pollutant strategy seems reasonable. The lack of experience in regulating Hg is reflected in proposed four-pollutant strategies. Some proposals simply defer the decision and implementation strategy to EPA; some require MACT on a unit-by-unit basis; and others would allow a trading system under an emissions cap ranging from 70% to 90% reduction.[23] At a 90% reduction cap, Hg allowances are likely to be very expensive, so the initial allocation of allowances would be a critical step in finding any acceptable strategy. Besides starting from near zero, any Hg trading system would also have to develop market institutions, including tracking, trading and other mechanisms to ensure a smooth working market.

Carbon Dioxide. Except for requiring utility monitoring of emissions, CO_2 is not controlled under the CAA, and controversy exists as to whether CO_2 should be considered a pollutant at all. The slim chance that the regulatory regime adopted at Kyoto would be ratified by the Senate contributed to the Clinton Administration's refusal to even submit the treaty to that body. At the same time, the country is obligated under the 1992 United Nations Framework Convention on Climate Change (FCCC) to pursue strategies with the goal of maintaining CO_2 emissions at their 1990 levels.[24] Current CO_2 emissions are about 10% above their 1990 levels.

In the face of scientific uncertainty, the focus of U.S. debate on a climate change policy can be categorized by the three-Cs: (1) cost (the impact on the economy); (2) competitiveness (impact of U.S. global competitiveness); and (3) comprehensiveness (desire for a level playing field for all countries). Consensus is difficult because of the wide range of cost estimates presented. A CRS survey of 17 costs estimates for the Kyoto Protocol resulted in a range of between \$23 and \$348 a metric ton of CO_2 removed.[25] Such an order of magnitude difference makes consensus difficult.

Several factors can both lower the cost and reduce the range of cost estimates presented above. One major factor in producing the \$23 - \$348 range is assumptions made about the viability of emissions trading under Kyoto. CO_2 reduction cost estimates for global emissions trading scenarios are in the range of \$23-\$50 a ton. However, serious questions have been raised as to whether the trading mechanisms embodied in the Kyoto Protocol could produce the cost savings suggested by some

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[23]For proposals introduced in the 106th Congress, see: Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326.

[24]See John Blodgett and Larry Parker, *Global Climate Change: Reducing Greenhouse Gases – How Much from What Baseline?* CRS Report 98-235 ENR.

[25]Larry Parker, *Global Climate Change: Lowering Cost Estimates through Emissions Trading – Some Dynamics and Pitfalls*, CRS Report RL30285.

studies.[26] Some of the these objections could be swept away under a properly designed four-pollutant strategy as its purpose would not necessarily be to comply with, or be compatible with, Kyoto. Indeed, several of the four-pollutant strategies proposed in the 106th Congress chose the FCCC 1990 stabilization target for their CO_2 cap, not the Kyoto reduction requirement.

Setting a CO_2 reduction target under a four pollutant strategy would be a very contentious issue. CO_2 emissions from electric generation have risen about 23% from 1990 to 2000. Add to this an additional 19% for increased emissions anticipated between 2000 and 2010, and a reduction requirement back to the FCCC target would be a substantial undertaking. However, the cost would be less than if the additional 7% required by Kyoto was added to the reduction requirement.

Several of the building blocks for a CO_2 cap and trade program are in place. There is an established baseline (1990), and a credible inventory for powerplant emissions. Continuous monitoring is required for powerplants under the 1990 CAAA. There is some experience with international emission credits thanks to the Joint Implementation program pioneered by the U.S. in the mid-1990s. The issues of baselines for international projects and domestic allocations would be contentious, but there is not the baggage included in those issues that there is with NOx control. The advantage of CO_2 not having been controlled is that policymakers can begin with a pretty clean sheet.[27]

Integrative Effects of Multi-Pollutant Strategy

The integrative effects of a multi-pollutant strategy are environmental, economic, and regulatory.

Environmental. Multi-pollutant controls would integrate efforts to address several environmental problems, including aquatic loadings (Hg deposition and acid rain (SO_2 and NOx)), health effects of fine particulates (SO_2 and NOx), and visibility impairment (SO_2 and NOx). Given the numerous effects and interactions of pollutants, a multi-pollutant strategy is likely to enjoy considerable benefits – along with the costs. What is hoped for is that the benefits will accrue at a rate faster than the rate at which costs rise.

Economic Effects. Economic effects – including energy effects – include both planning issues and compliance costs. EPA analyzed the costs and benefits of two multipollutant initiatives introduced in the 106th Congress: S. 172/H.R. 25 and H.R. 2569.[28] S. 172/H.R. 25 was a three-pollutant bill mandating 50% reductions in

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[26]ibid.

[27] For a discussion of alternative market mechanisms for CO_2 control, see: Larry Parker, *Global Climate Change: Market-Based Strategies to Reduce Greenhouse Gases*, CRS Issue Brief IB97057, updated regularly.

[28]EPA, *Analysis of the Acid Deposition and Ozone Control Act (S. 172)*, prepared for the Senate Subcommittee on Clean Air, Wetlands, Private Property, and Nuclear Safety, U.S.
(continued...)

SO_2 and NOx emissions by 2005, plus requiring an Hg regulation within one year, but without specifying a reduction percentage or target. The effect of this mandate would have been to cap SO_2 emissions from powerplants at 4.45 million tons annually (reducing emissions by approximately 3.7 million tons), and NOx emissions at 2.36 million tons (reducing emissions by approximately 2.1 million tons) annually. H.R. 2569 was a four-pollutant bill mandating annual emission caps on utilities of 4.0 million tons for SO_2 (reducing emissions by approximately 5.7 million tons), 1.66 million tons for NOx (reducing emissions approximately 2.4 million tons), 1.914 billion tons for CO_2, and a 90% reduction on a unit-by-unit basis for Hg from 1990 levels.[29]

Table 4 is derived from EPA analyses of the SO_2 and NOx reduction requirements of these two proposals. At first glance, the costs are not what one would expect. First, although the tonnage reduced by H.R. 2569 is 40% greater than

Table 4 : Estimated 2010 Cost and Benefits of S. 172/H.R. 25 and H.R. 2569

(1997$)

	S. 172/H.R. 25	H.R. 2569
SO_2 Reduced	3.7 million tons	5.7 million tons
NOx Reduced	2.1 million tons	2.4 million tons
SO_2/NOx Cost Per ton	$569	$580
Total Annual Cost in 2010	$3.3 billion	$4.7 billion
Total Annual Benefits in 2010	$33-$56 billion	$76.2 billion

Source: EPA analyses. Calculations adjusted to same baselines; costs exclude costs of Title IV compliance and the NOx SIP Call; benefits exclude the benefits of Title IV compliance but include the NOx SIP Call, for which relevant (PM) benefits would be minor, on the order of $0.5 to $2 billion per year; per ton costs derived by CRS from EPA analyses.

S. 172/H.R. 25, the costs only rise 42%, whereas one would expect costs rising more quickly as more reductions are achieved. Some of the reduction in anticipated costs can be explained by the combination of NOx and SO_2 included under each bill. Two

[28](...continued)
Senate, July, 2000; and, EPA, *Technical Assistance on H.R. 2569, The Fair Energy Competition Act of 1999*, prepared for Congressman Pallone, January 5, 2001.

[29]See Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326, July 26, 2000.

million of the 2.3 million ton difference between S. 172/H.R. 25 and H.R. 2569 is SO_2 reduction, the less expensive of the two pollutants to reduce.

EPA did not calculate separate cost-per-ton estimates for NOx and SO_2. As indicated in Table 4, the combined NOx/SO_2 cost per ton estimates only differ by about 2%. In its analysis of S. 172, EPA did calculate separate cost-per-ton estimates for NOx and SO_2 assuming separate implementation of the bill's provisions. Using the ratio of per ton costs resulting from those estimates, CRS estimated the per ton costs for the full bill at $482 for SO_2 and $728 for NOx. If it is assumed that the ratio holds for H.R. 2569, the resulting per ton costs are $508 and $762 – a 5% increase from S. 172. This increase seems low, given a 15% difference in NOx reductions and a 54% difference in SO_2 reductions between the two bills. EPA explains the relatively flat cost curves in the case of SO_2 emissions by arguing that the current 11 million tons of surplus SO_2 allowances under the title IV program hold down the increase in per ton costs.[30] These surpluses are seen by EPA as sufficient to dampen the effects of the controls mandated for 2005 even through the 2010 time period examined here.

However, this surplus does not explain the relatively flat NOx reduction costs. There are several possible explanations.[31] If the 11 million ton SO_2 allowance surplus projected by EPA is sufficient to prevent *any* per ton cost increase from the 2 million additional tons of SO_2 reduced annually by H.R. 2569, the resulting NOx cost per ton is $813 – about 12% above the NOx costs of S. 172. This estimate would appear more in line with the NOx reduction increase of 15% between the two bills. However, if correct, this result would suggest that the SO_2 allowance surplus is masking a significant increase in H.R. 2569 SO_2 compliance cost just beyond the year 2010.

The EPA analysis for H.R. 2569 also included Hg and CO_2 controls. For CO_2, the cost of reducing emissions to their 1990 levels is estimated by EPA at $3.82 billion.[32] EPA modeled the Hg provisions in a two-step process beginning with a source specific reduction of 73%, followed by a 5 ton Hg cap (equal to a 90% reduction in Hg) beginning in 2005. According to the analysis, the source specific reduction would cost $1.56 billion in 2010 and the further reduction via the cap would cost $1.43 billion. Thus, total Hg cost for a 90% reduction is about $3 billion annually in the year 2010. The total costs of the pollution control requirements of H.R. 2569 is presented in Table 5.

Utilities would meet these reduction requirements through a mix of technology, fuel choice decisions, and other means. EPA's analysis of S. 172/H.R. 25 suggests

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[30] Telephone communication with the Office of Clean Air Markets, U.S. EPA, February 2, 2001.

[31] For example, it is possible that achieving the reduction requirement involves technologies whose costs on a per ton basis are comparable, and the choice is dependent on the percentage reduction necessary and site specific considerations.

[32] Assuming EPA is using their base case as published in *Analysis of Emissions Reduction Options For the Electric Power Industry (U.S. EPA, March, 1999)*, the per ton costs works out to about $24 per metric ton of carbon reduced.

that NOx control would be primarily achieved through installation of control equipment. For coal-fired capacity, it is projected that half would install Selective Catalytic Reduction (SCR) and a quarter would install Selective Non-Catalytic Reduction (SNCR). For SO_2, it is projected that about a fifth of coal-fired capacity would install Flue Gas Desulfurization (FGD or scrubbers), while an undisclosed amount of capacity would switch to lower sulfur coal. Less than 1% of coal-fired capacity is projected to be repowered in order to burn natural gas.

Table 5: 2010 Annual Costs of Emission Reduction Provisions of H.R. 2569

(Billions of 1997 dollars)

Pollutant	Costs (incremental to title IV and NOx SIP Call compliance costs)
SO_2 and NOx (75% reduction from 1990 levels)	$4.72
CO_2 (return to 1990 level)	$3.82
Hg (90% reduction)	$2.99
Total	$11.53

Source: EPA analysis, January 5, 2001.

Proposals that include significant reductions in CO_2 emissions greatly increase the likelihood that natural gas may displace coal in fueling electric generating facilities. As stated by EPA in its H.R 2569 analysis: "The reduction in CO_2 to 1990 levels is projected under the current model to be accomplished through a shift towards lower emitting generating technologies and fuels, primarily natural gas-fired electricity generation."[33] Unfortunately EPA's H.R. 2569 analysis presents no data on its fuel source effects. However, other analyses done by EPA in 1999 do provide some idea as to the magnitude of this effect.[34] Using analyses incorporating a 50% SO_2 reduction from title IV levels, coal production in 2010 is projected at almost 1 billion tons. To reduce U.S. CO_2 emissions to their 1990 levels, as would have been required under H.R. 2569, these analyses indicate a 158 million metric ton reduction in carbon from EPA's 2010 baseline. Using EPA analyses of other reduction requirements as a guide, CRS estimates that coal production losses from such a requirement would be in the range of 300 million short tons (table 6). This production would be replaced mostly with natural gas, along with some additional conservation.

[33]U.S. EPA, *Technical Assistance on H.R. 2569, The Fair Energy Competition Act of 1999*, January 5, 2001, p. 6.

[34]U.S. EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry*, Office of Air and Radiation, March 1999.

Table 6: Illustrative Estimates of 2010 Coal Production Impacts from Carbon Reductions

Carbon Reduced (from 2010 baseline) (million metric tonnes)	Coal Production Loss (from 2010 baseline) (million short tons)
70	137
106	214
158	~300

Source: 70 million and 106 million estimate from EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry*, March 1999, p. 3-46. 158 million estimate derived by CRS from EPA report. Baseline includes an assumed 50% reduction in SO_2 below title IV levels.

Such a substantial change in compliance strategies highlights the arguments in favor of a comprehensive approach to controlling these four emissions in contrast to addressing them individually. Upfront knowledge of the reduction requirements could permit facilities to optimize compliance strategies rather than make costly investments that could be rendered obsolete by future regulatory decisions. The cost and other effects of control strategies for these pollutants are highly interdependent. As stated by EPA in its 1999 analysis of multi-pollutant options: "The analysis shows that having advance knowledge of potential requirements for all four pollutants could lead firms to follow significantly different compliance strategies at individual plants, compared with compliance choices made when the pollutants are addressed one-by-one."

These potential costs and fuel disruptions do not occur in isolation, however; the benefits must also be taken into account, as discussed below. Further, a integrated, multi-pollutant air pollution control regime may offer opportunities for utilities to reduce costs through comprehensive approaches to generation and control technologies and fuel choices.

Economic Benefits. As shown in table 4, EPA estimates that the benefits of S. 172/H.R. 25 and of H.R. 2569 greatly exceed costs. These figures are consistent with other EPA analyses of pollution control that find very substantial health benefits in terms of annual avoided costs from reductions in SO_2 and NOx. These benefits accrue primarily from avoided adverse health effects of $PM_{2.5}$ (SO_2 and, to a lesser extent, NOx contribute to $PM_{2.5}$). For the benefits shown in table 4, all but 1% or 2% are accounted for by the health benefits of $PM_{2.5}$ reductions, with the balance attributed to visibility improvements. EPA's analyses indicate that other benefits are likely, but they are not quantified. (It should be noted that these large estimates of benefits from $PM_{2.5}$ reductions have their critics.[35])

[35]On the issue of assessing PM health effects, see, for example, EPA, *Regulatory Impact* (continued...)

However, whether the costs of an integrated, multi-pollutant air quality program are justified can be evaluated not just in terms of the net benefits, but also from the comparison of the costs of the integrated approach to the costs of the current, pollutant-by-pollutant approach. This is discussed below.

Regulatory Effects. The regulatory effects of a four-pollutant strategy are probably the most difficult to determine. Two key dimensions of these effects would be (1) their impact on the other elements of the air quality control regimen and (2) their impact on the state, local, and private sector managers implementing the program.

In terms of the impacts on air quality control programs, integrating the four-pollutant strategy with the Title V permit process would probably be the easiest. Integrating the strategy with the NAAQS/SIP process would probably be the most difficult, since the cap and trade framework central to most multi-pollutant approaches focuses on total loadings, while the NAAQS process focuses on local ambient concentrations. The final disposition of other regulatory requirements, such as NSPS, NSR, visibility, and PSD would be problematic and surely the subject of considerable discussion.

If the debate on title IV is any indication, it might be argued that continuation of NSPS would be unnecessary under a comprehensive cap and trade program. Likewise, modification or streamlining of the NSR/PSD siting processes might also make sense. The logic for a multi-pollutant strategy modifying or replacing NSPS and NSR for the affected pollutants would be that neither program focuses on local ambient concentrations. A cap and trade approach could allow some new sources to emit more than allowed under NSPS or through NSR, if counterbalancing reductions occurred elsewhere.

The disposition of PSD and visibility requirements could be quite controversial. Unlike NSPS and NSR that focus on total emissions (like a cap and trade program does), visibility and PSD are concerned with ambient concentrations as well as loadings. If the cap were set stringent enough, it is possible that these ambient concentration concerns could be eliminated. Otherwise, some restriction on trading might be considered necessary.

From a political point of view, there would be tensions between the mix of potential synergies, certainties, and flexibilities introduced by a multi-pollutant approach on the one hand, and the fear that deleting any existing program could erode control capabilities on the other. Each existing element of the air quality control program developed through a legislative process involving negotiation and tradeoffs; those with stakes in those efforts might be expected to resist changes

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[35](...continued)
Analysis for Proposed Particulate Matter National Ambient Air Quality Standard (December 1996); on the debate on effects, see, for example, U.S. Congress, House, Committee on Commerce, Subcommittee on Health and Environment and Subcommittee on Oversight and Investigations, *Review of EPA's Proposed Ozone and Particulate Matter NAAQS Revisions,* Parts 1 & 2 [Serial No. 105-19 & 105-24] (105th Congress, 1st session) (Washington, D.C.: U.S. Govt. Print. Off., 1997).

unless the compensating advantages were obvious and substantial – and even then perceived symbolic values associated with a program might be hard to overcome.

Even harder to assess prospectively is the way in which a multi-pollutant approach might affect the air pollution control management task of state, local, and private sector managers. Past experience with the CAA suggests estimates of projected costs of compliance tend to be too high, as technological and managerial innovations bring down costs. A cap and trade approach, included in most multi-pollutant proposals, facilitates each manager's flexibility in seeking least-cost solutions to controlling emissions. At present, the CAA (with some exceptions, most obviously title IV) is based on each source making pollution control decisions pollutant-by-pollutant, smokestack by smokestack. The underlying presumption is that each manager will make the most cost-efficient decision, and the sum of those decisions will be an efficient outcome. Where the CAA provides for taking costs, energy, or other factors into account in setting standards, it is always in a pollutant-by-pollutant context.

The multi-pollutant approach pursues a new direction: that individual decisions within a collective framework, such as cap and trade, can be more efficient, by shifting controls to those sources where reductions can be least-cost. Thus it builds on the experience of the title IV program. Virtually all studies of trading mechanisms find that they lower costs, although by how much varies, depending on assumptions about transactions costs, the number of participants, and so on. But it is one thing to conclude that cap and trade will reduce costs of achieving reductions for any one pollutant; it is another to anticipate the implications of a multi-pollutant system allowing caps and trades for each pollutant, and giving managers the opportunity to address a suite of requirements across several pollutants. As noted above, compliance strategies for these pollutants are highly interdependent. EPA analyses suggest that synergies exist when addressing these pollutant comprehensively; for example, EPA estimates that controlling SO_2 and NOx separately would cost $300 million more than the integrated control program proposed under S. 172.[36]

Legislative Options

One thing is clear: a multi-pollutant approach would require legislation. As it stands, the CAA leads EPA to identify and assess the effects of pollutants one by one; and it directs EPA and the states to evaluate and mandate controls on most sources individually or by subdivided category (existing or new; large or small, etc.). With only a few exceptions, mainly involving mobile sources, the Act does not provide for integrating regulatory decisions, even when pollutants interact or have similar effects or are emitted by separate but similar sources. EPA therefore has little authority to develop and implement a regulatory approach that would embrace the collective emissions of a group of sources, even if it would achieve more cost-effective reductions and more efficient compliance by sources. At best, as in the

[36]EPA, *Analysis of the Acid Deposition and Ozone Control Act (S. 172)*, July 2000, p. 22. For a further discussion of cost savings from integrated control schemes, see EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry*, Office of Air and Radiation, April, 1999.

NOx SIP Call, EPA can ask states to cleave voluntarily to such a system – in this case a NOx cap and trade one.

Dimensions of a Cap and Trade Program. Essentially all multi-pollutant proposals have included cap and trade programs for all or most of the pollutants.[37] This common element underscores the presumption that cap and trade programs can be more efficient than command and control requirements on individual sources. Each pollutant raises particular questions about a cap and trade program. These include the following:

- **Scope.** For which pollutants would cap and trade programs be created – all or only some? (A national one exists for SO_2, and some regional efforts for NOx.) Would cap and trade programs be restricted only to power plants, or could other sources, stationary or mobile, opt in? How large would facilities have to be in order to be included?

- **Reduction Requirements.** At what levels would emissions caps be set? What baselines would be used? Would emission credits or allowances be allocated to sources free (as with acid rain), or would affected sources initially have to bid on pooled allowances? Would the caps be phased in with interim reductions? Would some regions get treated differently than others?

- **Time Frame.** Within what time frame should compliance be expected? Should there be exceptions for facilities that choose innovative control measures?

- **Techniques Permitted.** Should there be any restrictions on the methods used for compliance? Should incentives be included to encourage specific techniques or technologies?

- **Enforcement.** How would the cap and trade program be enforced? What changes in existing emissions monitoring requirements, or new monitoring, would be required? What would be the penalties for non-compliance?

Table 7 summarize the current status of the four pollutants with respect to a cap and trade program, which implies at least partial answers to some of the above questions. As indicated, each pollutant is differently positioned to incorporate a cap and trade program, and each raises several specific concerns that must be addressed.

[37] These cap and trade programs would be pollutant by pollutant; at the time of the acid rain debate there were some discussions of SOx-NOx interpollutant trading, but this idea has not been resurrected in the current debate.

Table 7: Current Status of Four Pollutants

Issue	SO_2	NOx	Hg	CO_2
Baseline and Emissions Inventory	Established national baseline and emissions inventory	Established emissions inventory - regional, not national baseline	No established baseline or emissions inventory	Established global baseline and national emissions inventory
Allocation Scheme	Existing national scheme	Some regional schemes (OTC)	Focus tends to be on percentage reduction and technology	Focus on 1990 emissions as allocation
Reduction Targets	Proposed 50%-70% below Title IV levels	Proposed 50%-70% reductions	Proposed 73% -90% reductions	Proposed 1990 stabilization (FCCC); Kyoto target proposes 7% reduction
Trading Schemes	Established trading system and institutions	Established regional trading systems and institutions	No experience and viability questioned	Some spotty domestic and international experience – mostly bilateral transactions
Monitoring	Existing	Existing	Limited	Existing
Comment	More stringent controls could reopen debate on allocations	Integrating regional/ seasonal programs difficult	Viability of trading questioned; baseline and inventory data, and monitoring inadequate	Setting targets, allocations, and the scope of acceptable credit sources are major issues

Regulatory Changes. Another aspect of establishing cap and trade programs for additional pollutants is what parts of the existing regulatory system (if any) would need to be modified – or might become superfluous and hence could be repealed. Table 8 summarizes some of the possibilities, along with potential concerns. As is evident, a concern inherent to the cap and trade approach is the possibility of creating

Table 8: Regulatory Issues Raised by Cap and Trade Proposals

Issue	Current Purpose	Issues Raised by Cap and Trade Proposal	Potential Concerns
NAAQS (including PM_{10} [potentially $PM_{2.5}$], SO_2, NOx, and Ozone (NOx SIP Call, Section 126 petitions, OTC))	Protection of human health with an adequate margin of safety	Emission caps are potentially a more efficient approach to reduce emissions – may make certain regulatory schemes such as the NOx SIP Call redundant and unnecessary	Protection against local “hot spots” that could violate NAAQS; modeling/ restriction of trades might be necessary to ensure compliance
PSD/NSR Permitting Procedures (New Sources or Major Modifications to Existing Sources)	Protect the integrity of the NAAQS and PSD increments (SO_2 and NOx)	Cap arguably makes plant specific review redundant; possible overlapping permitting requirements. Streamlining efforts could focus on existing Title V program	Protection against local “hot spots” that could violate NAAQS or PSD increments; modeling/ restriction of trades might be necessary to ensure compliance
NSPS/MACT	Minimize the environmental effects of new facilities (SO_2 and NOx)	Cap arguably makes separate control requirements on new facilities redundant	Hg MACT for utilities in future
PSD -Visibility	Protect currently pristine areas, and areas of particular importance (PM, SO_2, and NOx)	Cap arguably makes separate control requirements – PSD and BART – redundant and unnecessary.	Protection against local concentrations that compromise visibility; modeling/ restriction of trades might be necessary to ensure compliance

localized "hot spots" because of unrestricted trading. Such hot spots could potentially hinder compliance with NAAQS, PSD, or visibility objectives. Very stringent emissions caps would minimize the risk; modeling of major trades to determine their effect on local emission concentrations and restrictions on trades in certain areas could help ensure compliance with ambient requirements. The title IV SO_2 program prohibits any trade that would violate NAAQS. Terms that would have to be fleshed out would include "stringent," "major trades," and "certain areas."

Conclusion

The Clean Air Act has evolved over time in response to a developing understanding of the environment, new technologies, and changes in the nation's transportation, energy, and industrial sectors. The result has been a patchwork of requirements that are not always consistent – and may even be incompatible – at any given moment. Moreover, these requirements change and are added to over time. Although the resulting development of the Act has resulted in a structure that some consider unwieldy, emissions of most air pollutants have substantially declined, and the number of persons living in areas where pollution exceeds standards has diminished. Arguably, the Act's success puts the burden of proof for revising the existing structure on those favoring change.

The multi-pollutant proposals seek to bring more consistency and stability to the diverse elements of the Act, with the focus being on pollutants emitted by utilities, one of the largest emitting sectors. In a way, "multi-pollutant" may be misleading, as the proposals would not combine regulations or controls on several pollutants; rather, the proposals typically do several things:

- they would align pollution control processes and procedures for several currently regulated pollutants (SO_2 and NOx, and, indirectly, PM and ozone) so that both regulators and utility managers could anticipate requirements and integrate their decisions about how to control emissions;
- they would adopt the efficiency of economic mechanisms – most notably "cap and trade" – into the control of most or all of the pollutants;
- they would stabilize requirements over time; and
- they would anticipate incorporating potential future control requirements for other emitted gases (e.g., Hg, CO_2) into this more stable scheme.

For regulators, the advantages of this approach could be to reduce complaints about the costs and inefficiencies of the current system, and possibly to forestall litigation. For utility managers, the advantages of this approach could be to provide a certainty about environmental requirements over a several-year planning horizon (that must cope with restructuring changes and volatile energy prices), and to expand an existing method designed to achieve more cost-effective compliance. For environmental and health interests, the advantages of this approach could be to speed up reductions in emissions and, especially, to advance the controls on Hg and CO_2.

There are potential disadvantages, as well, depending on how the old (existing) system is adapted when and if a new, multi-media approach is enacted. Regulators and utility managers could find that the new approach merely adds more requirements, compounding the current complaints of regulatory overload. Utility managers could face having to control emissions (Hg and CO_2) not now regulated. Environmental and health interests might find that some existing protections would be removed, with the risk of local "hot spots" emerging where emissions threaten or even exceed current health standards or visibility requirements.

For legislators, then, the multi-pollutant approach represents an interlocking series of tradeoffs among numerous stakeholders. Achieving balance may be difficult, but the potential for all parties to find advantages could give impetus to the proposals.

Table 1A: Timeline of Major Federal SO_2 Regulations

Date	Affected Units	SO_2 Emission Limitation (lb.\MMBtu)	Comment
1971 National Ambient Air Quality Standard (NAAQS) for SO2 (40 CFR 50.4)	Affected Units determined by individual States in their EPA-approved State Implementation Plan (SIP)	Limitation calculated by State as that necessary to achieve the SO_2 NAAQS	SIP limitations generally met through increased use of lower sulfur coal
1971 New Source Performance Standard (NSPS) (40 CFR 60.43)	Fossil-fuel-fired steam generators over 73 MW on which construction commenced after 8/17/1971	Coal: 1.2 on a 30-day rolling average Natural Gas: none Oil: 0.8 on a 30-day rolling average	NSPS was met through low-sulfur fuels; natural gas emits virtually no SO_2 (0.0006 lb./MMBtu)
1977 Prevention of Significant Deterioration (PSD) Provisions (1977 CAAA, Part C)	Stationary sources in areas not covered by NAAQS non-attainment provisions	All new plants and modified existing plants must install Best Available Control Technology (BACT)	Additional controls or offset may be required unless the remaining emissions can be accommodated under the increment of increased SO2 concentrations allowed under the area's PSD classification

Date	Affected Units	SO_2 Emission Limitation (lb.\MMBtu)	Comment
1979 NSPS (40 CFR 60.43a)	Fossil-fuel-fired steam generators over 73 MW on which construction commenced after 9/18/78	Low sulfur coal: 70% reduction when emissions are less than 0.6 on a 30-day rolling average High sulfur coal: 1.2 and 90% reduction of uncontrolled concentrations on a 30-day rolling average Natural gas and Oil: 0.2 with no percentage reduction *or* 0.8 and 90% reduction of uncontrolled concentrations on a 30-day rolling average	New coal NSPS standard generally called the "scrubber requirement" because it led to installation of flue-gas desulfurization (FGD) units at facilities. About 25% of U.S. coal-fired capacity has FGD units installed
1996 Title IV requirements effective 1/1/96 (40 CFR 73.1-73.90)	265 *existing coal-fired* utility generating units specified for Phase 1 by Title IV of the 1990 Clean Air Act Amendments (Acid Rain Provisions)	Emission tonnage limitation based on a 2.5 lb. emission rate times a historical fuel consumption factor met on an annual average basis	Compliance generally achieved through use of low-sulfur coal on existing non-NSPS units

Date	Affected Units	SO_2 Emission Limitation (lb.\MMBtu)	Comment
2000 Title IV Requirements effective 1/1/2000 (40 CFR 73.1-73.90)	1,044 *existing coal-fired* utility generating units specified for Phase 2 by Title IV of the 1990 Clean Air Act Amendments (Acid Rain Provisions) Emissions from all *newly constructed* fossil-fuel-fired electric generating units over 25 MW that commenced operation after 11/15/90 must be offset to maintain a 8.95 million ton emissions cap on all fossil-fuel units	Emission tonnage limitation on existing facilities based on a 1.2 lb. emission rate times a historical fuel consumption factor met on an annual average basis New units may purchase SO_2 allowances from existing facilities to offset emissions	Emission limitation based on compliance through use of low-sulfur coal on existing non-NSPS units, although there are no restrictions on control methods
1997 PM2.5 National Ambient Air Quality Standard (NAAQS) (62 FR 38652-38760) [*NOTE: SO_2 emissions transform into PM2.5 in the atmosphere*]	Nationwide standard, but lack of monitoring data makes NAAQS non-compliance determinations difficult. Actual units affected would depend on individual State Implementation Plans (SIPs)	Depends on individual State Implementation Plans. A mixture of control methods at *existing units* would be a likely possibility	PM2.5 NAAQS is in litigation Lack of data and future reassessments of standard make any compliance deadline speculative at the current time

Table 2A: Timeline of Major Federal NOx Regulations

Date	Affected Units	NOx Emission Limitation (lb.\MMBtu)	Comment
1971 New Source Performance Standard (NSPS) (40 CFR 60.44)	Fossil-fuel-fired steam generators over 73 MW that construction is commenced after 8/17/1971	Coal: 0.7 on a 30-day rolling average Natural Gas: 0.2 on a 30-day rolling average Oil: 0.3 on a 30-day rolling average	NSPS was met through relatively simple boiler design and combustion modifications
1979 NSPS (40 CFR 60.44a)	Fossil-fuel-fired steam generators over 73 MW that construction is commenced after 9/18/78	Subbituminous coal: 0.6 on a 30-day rolling average Bituminous coal: 0.5 on a 30-day rolling average Natural gas: same as 1971 NSPS Oil: same as 1971 NSPS	New coal NSPS standards generally met through more combustion modifications or installation of Low NOx burners
1977 Prevention of Significant Deterioration (PSD) Provisions (1977 CAAA, Part C). NOx added in 1988 (40 CFR 51.166)	Stationary sources in areas not covered by NAAQS non-attainment provisions	All new plants and modified existing plants must install Best Available Control Technology (BACT)	Additional controls or offset may be required unless the remaining emissions can be accommodated under the increment of increased NOx concentrations allowed under the area's PSD classification

Date	Affected Units	NOx Emission Limitation (lb.\MMBtu)	Comment
1996 Title IV requirements effective 1/1/96 (40 CFR 76.5)	265 *existing coal-fired* utility generating units affected by Phase 1 of Title IV of the 1990 Clean Air Act Amendments (Acid Rain Provisions)	Tangentially-fired boilers: 0.45 on an annual average Dry bottom wall-fired boilers: 0.50 on an annual average	Compliance achieved through installation of Low-NOx burners on existing non-NSPS units. Affected units emitted 1.33 million tons in 1990; reduced to 0.94 million tons in 1998.
1997 NSPS (40 CFR 60.44a(d))	Fossil-fuel-fired steam generators over 73 MW that construction is commenced after 7/9/1997	Standard of 1.6 lb. per megawatt-hour gross energy output for new construction (equivalent to about 0.15 lb.\MMbtu heat input) on a 30-day rolling average is the same for all fossil fuels; standard of 0.15 lb.\MMbtu for modified or reconstructed facilities, on a 30-day rolling average	Not a major change for new natural gas/oil units which employ combined-cycle technology. Compliance by coal-fired units could involve a post-combustion device, such as Selective Catalytic Reduction (SCR) or Selective Non-catalytic Reduction (SNR)

Date	Affected Units	NOx Emission Limitation (lb.\MMBtu)	Comment
2000 Title IV Requirements effective 1/1/2000 (40 CFR 76.6-76.7)	1,044 *existing coal-fired* utility generating units affected by Phase 2 of Title IV of the 1990 Clean Air Act Amendments (Acid Rain Provisions)	Tangentially-fired boilers: 0.4 on an annual average Dry bottom wall-fired boilers: 0.46 on an annual average Cell burner boilers: 0.68 on an annual average Cyclone boilers: 0.86 on an annual average Wet bottom boilers: 0.84 on annual average Vertically fired boilers: 0.80 on annual average	Tangentially-fired and wall-fired boiler standard based on Low-NOx burner technology C-burner standard based on non-plug-in combustion controls Cyclone and wet bottom boiler standard based on SCR or natural gas reburning technology Vertically fired boiler standard based on combustion controls Incremental NOx reductions: 0.9 million tons annually

Date	Affected Units	NOx Emission Limitation (lb.\MMBtu)	Comment
2003 NOx SIP Call (and possible Section 126 determinations) (63 FR 57356-57538)	Affects 21 eastern States and D.C. Actual units affected depends on individual State Implementation Plans (SIPs). EPA budgets based on existing coal-fired boilers meeting a 0.15 lb. per MMBtu standard on an annual basis	Depends on individual State Implementation Plans. EPA budgets based on existing coal-fired boilers meeting a 0.15 lb. per MMBtu standard on an annual basis	NOx SIP Call and Section 126 determinations are in litigation Estimated NOx reductions from projected 2007 baseline: 0.96 million tons Flexible cap and trade implementation possibilities suggest a variety of potential control scenarios *NOTE: The Court has extended the deadline to May 31, 2004 and dropped one state from the rule's provision (Michigan v. EPA, No. 98-1497 (D.C. Cir., August 30, 2000))*

Table 3A: Timeline of Major Federal PM Regulations

Date	Affected Units	PM Emission Limitation (lb.\MMBtu)	Comment
1971 New Source Performance Standard (NSPS) (40 CFR 60.42) [*Note: PM defined as total suspended particulate matter 45 microns in diameter or less*]	Fossil-fuel-fired steam generators over 73 MW on which construction commenced after 8/17/1971	All fossil-fuel-fired generators: 0.10 on a 30-day rolling average	NSPS was generally met through installation of electrostatic precipitators (ESP); natural gas emits virtually no PM (0.01 lb./MMBtu)
1977 Prevention of Significant Deterioration (PSD) Provisions (1977 CAAA, Part C)	Stationary sources in areas not covered by NAAQS non-attainment provisions	All new plants and modified existing plants must install Best Available Control Technology (BACT)	Additional controls or offset may be required unless the remaining emissions can be accommodated under the increment of increased TSP concentrations allowed under the area's PSD classification
1979 NSPS (40 CFR 60.42a)	Fossil-fuel-fired steam generators over 73 MW on which construction commenced after 9/18/78	Coal: 0.03 and 99% reduction of uncontrolled concentrations on a 30-day rolling average Oil: 0.03 and 70% reduction of uncontrolled concentrations on a 30-day rolling average Natural gas: none	New coal NSPS standard generally met through larger ESPs, or with baghouses in the case of low-sulfur coal facilities

Date	Affected Units	PM Emission Limitation (lb.\MMBtu)	Comment
1987 PM10 National Ambient Air Quality Standard (NAAQS) (40 CFR 50.6) [*Note: PM10 defined as particulate matter 10 microns in diameter or less*]	Nationwide standard with most of the country currently in compliance. Actual compliance strategies were determined by individual State Implementation Plans (SIPs)	Dependant on individual State Implementation Plans. However, increased PM controls at *existing generating units* was a major component in most States' SIPs	Compliance was generally achieved through use of more sophisticated or larger ESPs
1997 PM10 National Ambient Air Quality Standard (NAAQS) (62 FR 38652-38760)	Only a slight refinement to PM10 NAAQS. Actual units affected would depend on individual State Implementation Plans (SIPs)	Depends on individual State Implementation Plans	1997 PM10 NAAQS is in litigation The 1997 NAAQS is not a major change from the 1987 NAAQS, and may not have a great effect on generating units
1997 PM2.5 NAAQS (62 FR 38652-38760) [*Note: PM2.5 defined as particulate matter 2.5 microns in diameter or less*]	See discussion in SO_2 table	See discussion in SO_2 table	Primary PM2.5 precursors include SO_2 and NOx. See discussion in SO_2 table