A Basis for Control of BART-Eligible Sources

prepared by

Northeast States for Coordinated Air Use Management (NESCAUM)

for the

Mid-Atlantic/Northeast Visibility Union (MANE-VU)

July 24, 2001

NESCAUM
Northeast States for Coordinated Air Use Management
129 Portland Street
Boston, MA 02114

TEL: 617-367-8540
FAX: 617-742-9162
http://www.nescaum.org

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Northeast States for Coordinated Air Use Management
(NESCAUM)

<u>Project Manager</u>

Gary Kleiman

<u>Editors</u>

Marika Tatsutani, Gary Kleiman, Arthur Marin

<u>Principal Contributors</u> (NESCAUM)

Praveen Amar
Gary Kleiman
Rawlings Miller
Marika Tatsutani
Ingrid Ulbrich

<u>USEPA Project Officer</u>

Russ S. Bowen (USEPA Region III)

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Tad Aburn, MD DEP
Andy Bodnarik, NH DES
Steve Botsford, NY DEC
Ann Marie DeBiase, MD DEP
Steve Dennis, MA DEP
Tom Downs, ME DEP
Wick Havens, PA DEP
Kirsten King, Fish and Wildlife Service
Tara Marie Koback, MARAMA
Denis Lohman, U.S. EPA
Jeff Peltola, OTC
Jim Ralston, NY DEC
Jim Salvaggio, PA DEP
Nancy Seidman, MA DEP
Don Shepherd, National Park Service
Gopal Sistla, NY DEC
Jeff Underhill, NH DES
Susan Wierman, MARAMA

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Unit, Species, Acronyms

Acronyms

AOI – Area Of Influence
AOV – Area Of Violation
ATAD – Atmospheric Transport and Diffusion Model
ANC – acid neutralizing capacity
BACT – Best Available Control Technology
BART – Best Available Retrofit Technology
CAA – Clean Air Act
CFR – Code of Federal Regulations
CM – Coarse Mass
EDAS – Eta Data Assimilation System
EIA – Energy Information Administration
EGU – Electricity Generating Unit
ETS – Emission Tracking System
FGD – Flue Gas Desulfurization
FLAG – Federal Land Managers' Air Quality Related Values Workgroup
IMPROVE – Interagency Monitoring of Protected Visual Environments
HYSPLIT – Hybrid Single-Particle Langrangian Integrated Trajectory model
LNB – Low NO_X Burner
MANE-VU – Mid-Atlantic/Northeast Visibility Union
MARAMA – Mid Atlantic Regional Air Management Association
MOU – Memorandum of Understanding
NAAQS – National Ambient Air Quality Standards
NADP – National Atmospheric Deposition Program
NESCAUM – Northeast States for Coordinated Air Use Management
NET – National Emissions Trends (USEPA)
NOAA – National Oceanic and Atmospheric Administration
NSPS – New Source Performance Standard
NSR – New Source Review
OTAG – Ozone Transport Assessment Group
OTC – Ozone Transport Commission
OTR – Ozone Transport Region
RADM – Regional Atmospheric Deposition Model
RPO – Regional Planning Organization
SCC – Source Classification Codes
SIC – Standard Industrial Classification
SIP – State Implementation Plan
SCR – Selective Catalytic Reduction
SNCR – Selective Non-Catalytic Reduction
STAPPA/ALAPCO – State and Territorial Air Pollution Program Administrators / Association of Local Air Pollution Control Offices
USEPA – United States Environmental Protection Agency
WRAP-Western Regional Air Partnership

Chemical Species

EC – elemental carbon
HSO_4 – bisulfate
H_2SO_4 – sulfuric acid
HNO_3 – nitric acid
NO_X – oxides of nitrogen (NO_2 and NO)
NO – nitric oxide
NO_2 – nitrogen dioxide
NO_3 – nitrate
NH_3 – ammonia
$(NH_4)_3H(SO_4)_2$ – letovicite
NH_4HSO_4 – ammonium bisulfate
$(NH_4)_2SO_4$ – ammonium sulfate
NH_4NO_3 – ammonium nitrate
OC – organic carbon
$PM_{2.5}$ – particle matter up to 2.5 µm in size
PM_{10} – particle matter up to 10µm in size
PM_{coarse} – the difference: $PM_{10} – PM_{2.5}$

S – sulfur
Se – selenium
SO_2 – sulfur dioxide
SO_4 – sulfate
VOC – volatile organic carbon

Units
Length
m – meter
μm – micrometer (0.000001m; 10^{-6}m)
km – kilometer (1000 x m; 10^3 m)
Mm – Megameter (1000000 x m; 10^6 m)

Volume
L – liter
m^3 – cubic meter

Mass
lb – pound
g – gram
μg – micrograms (0.000001 x g; 10^{-6} g)
kg – kilograms (1000 x g; 10^3 g)

Power
W – watt (Joules/sec)
kW – kilowatt (1000 x W; 10^3 W)
MW – megawatt (1000000 x W; 10^6 W)

Energy
Btu – British Thermal Unit (= 1055 Joules)
mmBtu – million Btu
MWh – megawatt hour
kWh – kilowatt hour

Concentration
$\mu g/m^3$ – micrograms per cubic meter

Visibility
dv – deciview
km – visual range in kilometers
Mm^{-1} – extinction in inverse megameters

Executive Summary

A. Overview

In January 2001, the U.S. Environmental Protection Agency (USEPA) completed proposed guidelines for the interpretation and implementation of Best Available Retrofit Technology (BART) requirements in the context of the 1999 "regional haze rule" [64 Fed. Reg. 35714 (July 1, 1999)]. The recent publication of the BART guidelines as a proposed rule in the Federal Register [66 Fed. Reg. 38108 (July 20, 2001)] has initiated a formal rulemaking to clarify current requirements contained in the regional haze rule for the protection of visibility in our nation's largest national parks and wilderness areas ("Class I" areas).[1] BART is the primary mechanism for regulating haze-forming pollutants from stationary sources and a new rulemaking process gives urgency to understanding the implications of the proposed BART guidelines.

The Northeast States for Coordinated Air Use Management (NESCAUM) undertook this study – on behalf of the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization (MANE-VU RPO) to assist the Northeast and Mid-Atlantic States and interested tribes in developing state and tribal implementation plans to address visibility impairment.[2] This study was designed to evaluate the potential applicability of BART to emissions sources affecting Class I areas in the MANE-VU region. In particular, NESCAUM sought to assess potential reductions in emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) achievable through the application of BART to fossil fuel fired power plants.

This analysis involved: (1) identifying the region of influence for Class I areas in the Northeast; (2) identifying electric generating plants potentially eligible for BART based on the plant age and emission criteria defined in the regional haze rule; (3) obtaining emissions estimates for BART-eligible sources; (4) identifying likely control technologies; and (5) determining the level of potential emission reductions achievable through the application of BART controls to eligible sources. While this study targeted emissions of SO_2 and NO_X from electric generating plants, other pollutants and source categories will eventually need to be addressed as part of a comprehensive strategy for achieving the nation's ambitious goal of restoring pristine visibility conditions to all Class I areas. This report also includes a discussion of the relationship between BART controls for visibility improvement and other regulatory programs targeting SO_2 and NO_X reductions from the electric power sector.

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[1] There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

[2] NESCAUM, MARAMA and the OTC are working in partnership with USEPA and federal land management agencies to coordinate haze planning for the Northeast and Mid-Atlantic States and interested tribes. The states include: Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. The interested tribes include the Penobscots and the St. Regis Mohawks. MANE-VU was formed to assist these states and tribes in complying with the requirements of the regional haze rule. Previous documents produced by the RPO have referred to the "OTC RPO" which has now been formalized as MANE-VU.

This is the second report issued by NESCAUM on regional haze and visibility impairment in the Northeast and Mid-Atlantic region. The previous study (released in January 2001 and available at www.nescaum.org) provides a comprehensive description of the regional haze problem in this region as well as other information relevant to a BART assessment, including more detail on the causes of visibility impairment, related regulatory requirements, and atmospheric chemistry and modeling.

B. Nature and Extent of Visibility Impairment in the Region

Visibility impairment throughout the Northeast and Mid-Atlantic region is caused by fine particles in the atmosphere that absorb and scatter visible light. Average visibility in the region is substantially impaired relative to pristine conditions. On the 20 percent haziest days, visual range at the region's Class I sites ranges on average from 20 to 40 km. By comparison, average visual range under unpolluted "natural" conditions is estimated to be over 160 km. On most days, sulfate is by far the single most important constituent of ambient fine particle pollution, accounting for half to two thirds of fine particle mass and 70 to 80 percent of total visibility impairment at the region's Class I sites. Other important contributors to fine particle mass concentrations and associated light extinction include organic carbon, nitrate, elemental carbon (soot) and soil or other crustal material (including sea salt, dust, etc.). The sulfate contribution tends to be especially high on the worst visibility days, predominantly in the summertime, though it plays a dominant role year-round, including on the best visibility days. By contrast, the nitrate contribution tends to be relatively higher in the wintertime, while the contributions of organic carbon and crustal material (both of which may be at least partially "natural" in origin[3]) tend to be somewhat more important on the best visibility days.

Secondary pollutants like sulfate and nitrate are chemically formed in the atmosphere from precursor emissions – in this case, SO_2 and NO_X, respectively. While industrial sources, such as refineries and smelters, contribute substantially to SO_2 emissions, the chief source of these emissions in the eastern U.S. is fossil fuel-fired electricity production, which accounted for two-thirds of the national SO_2 inventory in 1998. Power plants are also major emitters of NO_X, though mobile sources – including cars, heavy-duty trucks and various nonroad equipment and other sources – are also important contributors to total emissions of this particle precursor. Organic carbon aerosols are formed from a vast variety of precursor emissions whose sources include gasoline and diesel engines, solvents and coatings, industrial processes, fires and even biogenic sources (i.e. plants).[4] Sources of elemental carbon include diesel combustion and wood smoke.

Fine particles and their precursors are associated with a variety of negative environmental and public health impacts, apart from their deleterious effects on visibility. Sulfate and nitrate in the atmosphere lead to acid deposition which is damaging to forests and aquatic ecosystems; NO_X emissions contribute to soil nitrification and the eutrophication of sensitive waterbodies;

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[3] Up to half of the volatile organic compound (VOC) emissions that contribute to fine particle formation may consist of biogenic compounds emitted by certain plant species.

[4] Secondary organic particles are the result of condensational processes involving hundreds of VOCs and their breakdown products. The exact composition of secondary organic particles is a continuing area of scientific research.

NO_X and organic compounds are together the key ingredients of ozone smog; and fine particle pollution generally has been linked to a variety of serious public health risks – including excess morbidity and mortality from cardiac and respiratory ailments – as well as climate impacts.[5]

C. BART Requirements

Under USEPA's 1999 regional haze rule, certain emissions sources that "may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART). These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act.

BART requirements pertain to 26 specified major point source categories, including power plants, smelters, chemical and petroleum plants, and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments, which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically. In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible, market-based approaches, provided such alternatives can be shown to achieve *greater* progress toward visibility objectives than the standard BART approach.

In developing future haze implementation plans, states and tribes will need to include an inventory of emissions from potentially BART-eligible facilities in their jurisdictions and specify the timetable and stringency of controls to be applied at those sources. In determining what level of control represents BART, states must address the following considerations for each eligible source or group of eligible sources:

- Compliance costs,
- Energy and non-air quality environmental impacts,
- Any existing pollution control technology in use at the source,
- The remaining useful life of the source, and

[5] Particles in the atmosphere are known to play a significant role in offsetting or "masking" the greenhouse effect by reflecting sunlight directly and increasing cloud formation. In addition, a recent study by Prinn, et al. (2001) suggests that fine particle pollution may possibly play a role in enhancing the climate-altering potency of greenhouse gases.

- The degree of visibility improvement that may reasonably be anticipated to result from the imposition of BART.

It is imperative that USEPA's final BART rules address key questions such as what defines "unreasonable compliance costs," "unacceptable energy issues," and "unacceptable non-air quality environmental concerns," since these definitions could significantly affect the strength of any future control program.

D. Identification of Geographical Source Regions Affecting Class I Areas in the Northeast and Mid-Atlantic Region

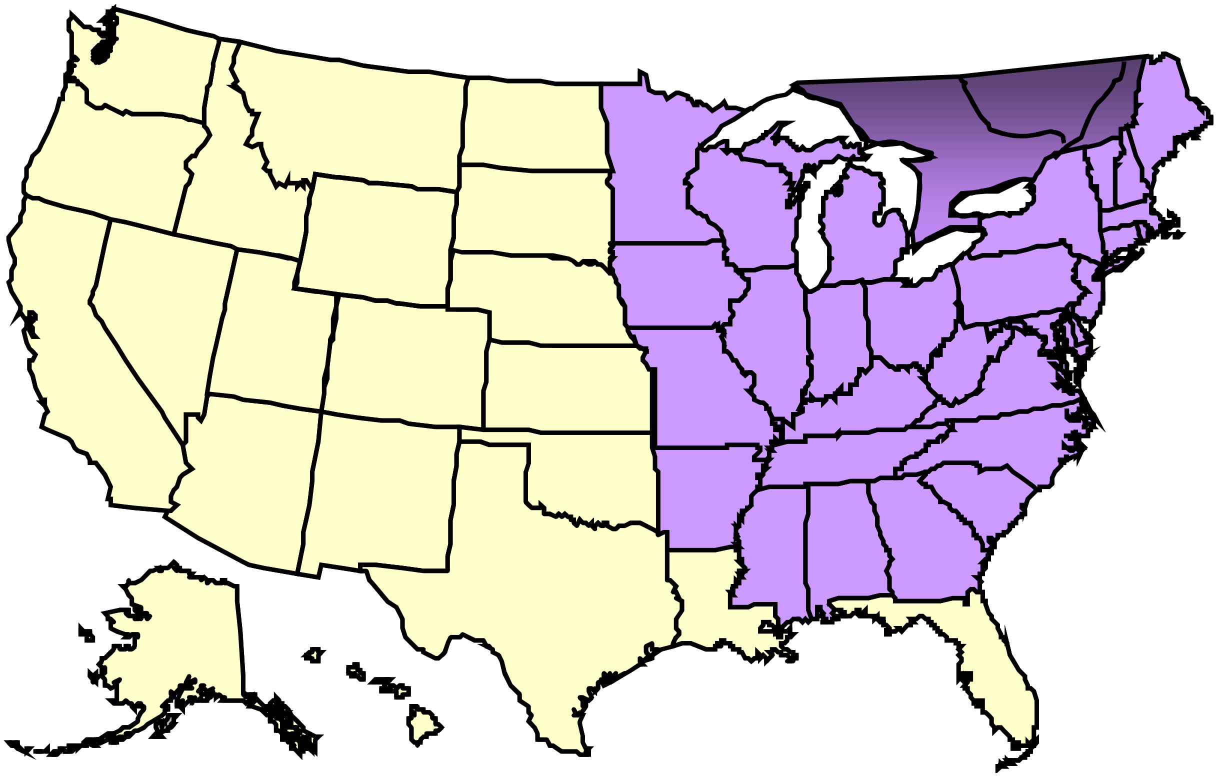
As a first step toward assessing the potential scope and magnitude of future BART controls, this study reviews available information for identifying source regions contributing to visibility impairment at Class I areas in the Northeast and Mid-Atlantic region. The fact that the long-range transport of airborne particles and their precursors in the atmosphere plays a major role in determining downwind visibility conditions is well established and forms the basis for USEPA's 1999 regional haze rule. The key sulfate precursor, SO_2, has an atmospheric lifetime of several days and is known to be subject to transport distances of hundreds of miles. USEPA estimates that one-third of the SO_2 emitted by power plants in the Ohio River Valley is carried over 400 miles from its point of origin prior to deposition. NO_X and some organic carbon species are also subject to long-range transport, as are small particles of soot and crustal material.

Various methods have been used to identify the geographic origin of pollutants contributing to visibility impairment in the Northeast and Mid-Atlantic region. In the early 1990s, back trajectory analyses – in which meteorological data are used to reconstruct the prior path of air masses arriving at a particular monitoring site – identified the probable source region for sulfates arriving at Acadia National Park in Maine as including central Michigan, Illinois, Ohio and parts of Canada, as well areas within the Ozone Transport Region.

More recently, NESCAUM has used updated emissions inventories and additional modeling tools to explore the correlation between sulfate deposition (as a surrogate for ambient sulfate levels) at the more northern Class I areas and SO_2 emissions from major sources in upwind areas. Updated trajectory work has extended these analyses to identify a source region for pollutants arriving in New Jersey's Brigantine Wilderness Area, Vermont's Lye Brook Wilderness Area and Acadia National Park on days with the worst visibility conditions between 1997 and 1999. This preliminary work identified the source region for sulfate as extending across approximately 29 eastern states plus the District of Columbia and parts of Ontario and Quebec (shown in Figure 1).

This report also summarizes the results of recent source apportionment studies conducted by the Vermont Department of Environmental Conservation to further refine current understanding of the source regions that impact visibility at the Brigantine site. After identifying 11 distinct source profiles that together can explain 90 percent of measured fine particle mass at Brigantine, Vermont researchers applied trajectory analysis to those days on which the mass concentrations of certain particle constituents were especially high. The results of these analyses are generally consistent with those of earlier studies and suggest that the greatest impact on

Figure 1: Source region reasonably anticipated to cause or contribute to visibility impairment on the 20 percent worst visibility days at Northeast and Mid-Atlantic Class I areas.



visibility in Northeast and Mid-Atlantic Class I areas is due to coal combustion sources in the Ohio River and Tennessee Valley areas of the Midwest and Southeast U.S.

E. Emissions Sources and Control Strategies

Reducing SO_2 emissions presents an obvious target of opportunity for achieving near-term visibility improvement in Northeast and Mid-Atlantic Class I areas. Sulfate is the major contributor to regional haze in the eastern U.S. and many of the major sources of SO_2, including large power plants, are included among the 26 source categories eligible for BART requirements. BART-eligible source categories account for 86 percent of total SO_2 emissions in the 29-state source region tentatively identified as contributing to visibility impairment in the Northeast and Mid-Atlantic region.

The draft BART guidance recently published by USEPA proposes flue gas desulfurization (FGD) or "scrubber" technology as the presumptive BART for reducing SO_2 emissions from electricity generating units. FGD is a well-developed, commercially available control technology that is routinely capable of reducing SO_2 emissions rates by 95 percent or more at uncontrolled sources. Assuming that SO_2 emissions rates from all potentially BART-eligible units[6] that are not already equipped with scrubbers could be reduced by 95 percent from 1999 emissions levels suggests available reductions in the 29-state region of over 5 million tons annually. This represents approximately half of total SO_2 emissions from all electricity generating units in the same source region (including units that do not meet BART-eligibility requirements) and is greater than the total additional reductions required on a national basis to achieve the Acid Rain Program's eventual 8.9 million ton annual SO_2 cap. Thus, the BART program represents a substantial opportunity for reduction of SO_2 emissions relative to national goals and must be considered in the context of ongoing control programs. It should be noted that the above estimate may somewhat overstate actual reductions achievable through a source-by-source application of BART if plants currently operating on low-sulfur coal for purposes of Title IV compliance switch to higher sulfur coal once they are required to install scrubber controls.

A similar analysis was used to estimate potential NO_X reductions achievable from the application of BART to large power plants in the same source region. In this case, NESCAUM identified modern selective catalytic reduction (SCR) control technology, in combination with combustion modifications (such as low-NO_X burners or LNB), as the presumptive control technology and assumed 94 percent control effectiveness at presently uncontrolled units.[7] Applying these control estimates to the same 387 potentially BART-eligible units identified in the SO_2 analysis produces estimated annual NO_X reductions of just over 2 million tons (based on 1999 pre-SIP call control levels).[8] As with SO_2, this estimate is intended to represent maximum reductions achievable by commercially available control technologies. Achievable NO_X reductions at certain facilities may be somewhat lower than those estimated for purposes of this analysis.

F. Integrating BART Implementation with Existing Regulatory Programs

There will be considerable overlap between the aggregate reductions achievable through BART implementation in the 29-state source region and aggregate reduction requirements under existing regulatory programs. It may be preferable (and more efficient) to modify existing programs so that they achieve multiple policy objectives – including visibility improvement – rather than to overlay new regulatory requirements on top of existing programs. In the case of SO_2, for example, it is obvious that the cap established by current Title IV requirements is not sufficiently stringent to remedy visibility impairment at all Class I areas around the country or to address growing concerns about continued problems with acidification in sensitive northeastern ecosystems. A better approach in this situation may be to substantially lower the current cap – as

[6] Our analysis identified 387 steam electric boilers in the 29-state source region that met BART-eligibility criteria in terms of potential to emit and date of first operation. (See Appendix A.)

[7] Units already equipped with low- NO_X burners were assumed to be operating at 35 percent control efficiency compared to uncontrolled boilers. A further 90 percent reduction was applied to these units to reflect additional NO_X reductions from SCR. Finally, it was assumed that units already equipped with SCR could not achieve any further reductions.

[8] The NOx SIP call was promulgated by USEPA in 1998 under Section 110 of the Clean Air Act, which provides for federal intervention to address ozone transport. As amended by subsequent litigation, the SIP call will require 19 eastern states to submit implementation plans aimed at substantially reducing summertime NOx emissions from major point sources by 2004. In a related action authorized under a separate section of the Act, Section 126, several Northeast states have petitioned for relief from upwind NOx emissions. Emissions reduction obligations resulting from state 126 petitions are due to be implemented by 2003.

various state and federal policymakers have recently proposed – while leaving in place many of the market mechanisms credited with reducing the economic costs of the existing Acid Rain Program.

In the case of NO_X, the same control technologies needed to satisfy BART requirements will be needed to achieve compliance with the USEPA NO_X SIP call and related state Section 126 petitions. Applying Selective Catalytic Reduction (SCR) controls to all BART-eligible boilers in the preliminary 29-state source region can be expected to yield aggregate summertime emissions reductions of over 800 thousand tons and over 2 million tons annually. The summertime reductions represent more than three-quarters of total seasonal reductions required under pending ozone mitigation programs.[9] The chief differences between existing NO_X SIP call/Section 126 requirements and potential new BART requirements are: (1) the NO_X SIP call applies to sources of all ages, and (2) the existing programs – because they are geared toward reducing ozone smog formation, a summertime phenomenon – require NO_X reductions only between May 1 and September 30. By contrast, the nitrate contribution to visibility impairment is a year-round concern and is, in fact, accentuated during the winter months. In this context, one obvious option for integration is to simply extend current NO_X SIP call and related requirements to the other months of the year. This would roughly double the annual NO_X reductions otherwise achieved by summer-only programs and would address other year-round problems associated with nitrate pollution, including fine particle formation, acid deposition, soil nitrification and eutrophication of surface waters. Going from a seasonal program to an annual program is likely to be highly cost-effective given that there would be no additional capital costs for installing controls, only additional operating expenses.

Another regulatory program that is closely linked to future efforts to implement the regional haze rule is the National Ambient Air Quality Standard (NAAQS) for fine particulate matter ($PM_{2.5}$) promulgated in 1997. Because visibility impairment is caused primarily by particles within the size range regulated under the new standards, efforts to reduce haze will reduce fine particle pollution and vice versa. Because of the synergy between the two programs, many of the statutory deadlines in USEPA's 1999 regional haze rule are explicitly tied to the designation of $PM_{2.5}$ non-attainment areas and to state submittals of $PM_{2.5}$ attainment plans.[10]

Consistent with the approach taken in the regional haze rule, USEPA has emphasized that regional strategies may be necessary to effectively address $PM_{2.5}$ nonattainment. For states in non-attainment of new fine particle standards, the implementation of BART requirements under the auspices of the regional haze rule could make a substantial contribution toward required attainment demonstrations. Similarly, measures taken to achieve compliance with the new $PM_{2.5}$ NAAQS may constitute much of a given state's demonstration of "reasonable progress" toward visibility goals during the first regional haze compliance period (2008-2013). High $PM_{2.5}$ levels in urban areas may require local remedies in addition to any regional measures implemented under the regional haze rule.

[9] Although the source regions potentially affected by these programs are likely to be roughly consistent, the summertime BART total is somewhat less than the aggregate reduction required under the NO_X SIP call because the latter program applies to all large boilers, not just those constructed between 1962 and 1977.
[10] A detailed description of these linkages and of the timeline of regulatory requirements under the 1999 regional haze rule is provided in the earlier NESCAUM haze report (NESCAUM, 2001).

Pollutants and sources other than those that have been emphasized in this report (i.e. SO_2 and NO_X emissions from power plants) contribute to both fine particle pollution and visibility impairment. These include organic compounds, elemental carbon (or soot), ammonium and crustal material (such as salt, soil and dust) that are emitted by a wide range of sources including automobiles, diesel engines, solvents and coatings, manufacturing processes, agricultural activities and other industrial sources besides large steam electric boilers. Further reductions in these emissions from a variety of sources, including many source categories that are presently excluded from BART requirements, will certainly be necessary to restore pristine visibility conditions in Class I areas and, in many cases, to achieve compliance with $PM_{2.5}$ ambient air quality standards. Ultimately, the most important synergy between haze and $PM_{2.5}$ attainment programs may be the fact that visibility goals will provide impetus for ongoing efforts to reduce pollution from a wide range of sources, even after applicable NAAQS are attained. Given that there appears to be no threshold below which fine particle pollution is not detrimental to human health, such reductions will continue to provide broad-based public health benefits. In many northeastern states, for instance, where $PM_{2.5}$ standards are already very close to being met, visibility requirements may provide an important mechanism for sustained progress toward healthier air.

A final argument for integrating BART implementation with existing regulatory programs relates to minimizing control costs and reducing administrative complexity for both regulators and affected industry. Control technologies available for reducing SO_2 and NO_X emissions are highly cost-effective. In addition, technological improvements can be expected to further lower these costs. Carefully designed regulatory programs that make appropriate use of market-based mechanisms, while providing flexibility and incentives for continued innovation can further reduce compliance costs. To the extent that future efforts to implement BART and other visibility-based pollution reduction programs can be integrated with existing regulations, economic efficiency will be enhanced, as will public support for the continued emission reduction efforts needed to achieve national visibility goals.

G. Conclusions

As Northeast and Mid-Atlantic States (and potentially Tribes) begin to develop haze implementation plans they will need to further refine the identification of geographic source regions, and their assessments of different emissions sources and possible control strategies. However, as this report and NESCAUM's previous assessment of regional haze in the region indicate, future planning efforts can draw from a considerable foundation of existing information. Further research is probably not needed, for example, to conclude that sulfate plays a major role in visibility impairment throughout the eastern U.S. and that further reductions in SO_2 emissions present an obvious area of opportunity for near-term progress in mitigating haze. Similarly, the different analyses described in Chapter IV present a compelling weight-of-evidence case for concluding that the geographic source region for visibility impairing pollutants in Northeast and Mid-Atlantic Class I areas extends at least as far west and south as the Ohio River and Tennessee Valley areas.

Having identified primary source regions and emissions reduction opportunities, the remaining challenge is to build consensus on a regulatory framework which advances visibility goals, reduces public health threats and environmental harms, and is both economically and politically viable. In meeting that challenge it may be useful to move toward a "one atmosphere" approach that considers all potential threats to public health and the environment and regulates in a manner designed to achieve multiple objectives using a unified and consistent approach. To implement this approach and to promote the integration of BART reductions with other regulatory programs, policymakers and regulators should consider:

- Establishing a single trading currency for each pollutant subject to trading programs,
- Strengthening caps while maintaining existing market mechanisms that deliver flexibility and encourage cost-effective pollution control strategies,[11]
- Ensuring that future regulations provide incentives for continued technological innovation, early compliance, and over-compliance,
- Promoting strategies that reduce emissions of multiple pollutants simultaneously, and
- Developing regulatory assessment methodologies that account for multi-pollutant benefits (in the sense that reducing one type of pollutant may have multiple public health and environmental benefits, and in the sense that some control strategies may reduce multiple types of pollution).

In addition to these general recommendations for future control programs, specific actions by USEPA should be taken now to ensure that the BART control measures described in the proposed guidelines remain a strong and binding means of reducing the environmental and public health threats presented by fine particle pollution, while simultaneously improving the quality of life in our wild lands and in our urban centers. USEPA should:

- Maintain the BART presumptive level of control for SO_2 emission sources at 90-95 percent control efficiency (equivalent to the installation of best available FGD control technology),
- Establish a BART presumptive level of control for NO_X emission sources at 94 percent control efficiency (equivalent to the installation of a combination of best available LNB and SCR control technologies),
- Provide additional specificity with regard to what constitutes a "non-trivial" contribution to downwind visibility impairment,

[11] Note that, depending on the geographic area included in the trading program, additional measures may be needed to ensure that enough of the reductions achieved under that program occur where they will provide the desired level of air quality improvement, whether with respect to downwind visibility conditions or fine particle NAAQS attainment. In addition, growing awareness of more localized pollution impacts and environmental justice concerns has increasingly led community groups and public health advocates to insist that a minimum level of pollution control be applied at certain facilities. These issues will need to be carefully considered in updating and possibly modifying some market-based programs, especially those – like the Acid Rain Program – that are national in scope.

- Provide additional specificity with regard to what constitutes "unreasonable" compliance costs, "unacceptable" energy impacts, and "unacceptable" other non-air quality environmental impacts, and

- Provide additional specificity as to how alternative trading programs would interact with existing regulatory programs, including how geographic considerations would factor into trading mechanisms (e.g. geographic restrictions on inter-RPO trading or intra-RPO trading between BART-eligible and BART-ineligible sources).

The MANE-VU RPO is preparing formal comments on the recently published BART guidelines on behalf of its member states and tribes. These comments will address all of the issues identified in this report and provide suggested language for remedying deficiencies in the current proposed rule. In addition to the issues raised here, many other issues must be addressed in order to construct an effective control program to aid in achieving the visibility goals described in the regional haze rule. However, given our fairly complete understanding of the major sources of visibility impairment in the East and the availability of cost-effective controls, initial planning efforts for regional haze mitigation should not be delayed while final details of the BART program are debated.

I. Introduction

Since 1977, Section 169 of the federal Clean Air Act (CAA) has called for the restoration of pristine visibility conditions in "Class I" national parks and wilderness areas.[12] National efforts to achieve this goal were given new impetus in 1999 when the U.S. Environmental Protection Agency (USEPA) issued an updated set of haze regulations. Commonly called the "regional haze rule," these regulations set a 2064 deadline for achieving national visibility goals and, for the first time, seek to combat visibility impairment on a regional basis [64 Fed. Reg. 35714 (July 1, 1999)]. As a consequence, states throughout the eastern U.S. – including those that do not host Class I areas – will need to reduce emissions of haze-forming pollutants that contribute to visibility impairment in downwind national parks and wilderness areas.

From the beginning, regulations requiring that Best Available Retrofit Technology (BART) be installed on emissions sources to which visibility impairment in Class I areas could be "reasonably" attributed have been a key component of the federal haze program. Until recently, however, the application of BART requirements has been limited to a relatively small number of cases where a particular source, or group of sources, was causing obvious plume blight in an adjacent wilderness area. Under the regional haze rule, which explicitly seeks to address the cumulative effect of numerous air pollution sources distributed over a wide geographic region, BART requirements have the potential to affect a much larger number of sources. The purpose of this report is to (1) evaluate the potential impact of BART requirements under the 1999 regional haze rule and USEPA's more recent proposed BART guidance;[13] (2) explore the relationship of haze-related control requirements to other regulatory programs, especially those aimed at addressing acid rain, ozone smog and fine particle pollution; and (3) put current regulatory efforts in the context of the longer term emissions reductions that will be needed to fully achieve the nation's ambitious visibility goals.

This report follows an earlier study released in January by the Northeast States for Coordinated Air Use Management (NESCAUM)[14] detailing the nature and scope of current visibility impairment in the Northeast and Mid-Atlantic States (NESCAUM, 2001). Like the earlier report, it is intended to assist the Mid-Atlantic/Northeast Visibility Union Regional Planning Organization (MANE-VU RPO) in coordinating regional haze planning efforts by the Northeast and Mid-Atlantic States and Tribes.[15] Chapter II provides a brief overview of visibility impairment and its causes in the eastern U.S., summarizing the more detailed information contained in the earlier NESCAUM

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[12] Specifically, the CAA calls for the prevention of any future, and the remedying of "any" existing man-made visibility impairment in Class I areas. The Class I designation applies to national parks exceeding 6,000 acres; wilderness areas and national memorial parks exceeding 5,000 acres; and all international parks in existence prior to 1977. The seven Class I areas in the Northeast and Mid-Atlantic region are described in Chapter II.

[13] Proposed guidelines for implementation of BART requirements under the 1999 regional haze rule were published in the Federal Register on July 20, 2001 and are included as Appendix C of this report. The publication of these guidelines initiates a formal rulemaking process. Interested parties have until September 18, 2001 to submit comments on the proposed rule to the docket.

[14] NESCAUM is a voluntary, non-profit association of the air quality management agencies of eight northeastern states, including Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont.

[15] In keeping with the regional focus of the 1999 rule, USEPA has designated five RPOs to coordinate multi-state haze planning efforts around the country. The MANE-VU RPO includes the six New England states, New York, New Jersey, Pennsylvania, Maryland, Delaware, the District of Columbia as well as interested tribes and federal land managers.

report and highlighting its most important findings. Chapter III reviews the specific requirements of the BART program, including proposed BART guidance (see footnote 13). Chapter IV details available evidence for identifying the geographic source region of pollutants contributing to visibility impairment in Northeast and Mid-Atlantic Class I areas. Chapter V then estimates the emissions reductions achievable by applying BART requirements throughout the geographic source region identified in Chapter IV, while Chapter VI explores the integration of haze-related control efforts with other regulatory programs. Chapter VII presents conclusions and provides a number of recommendations, most of them aimed at strengthening USEPA guidance on BART implementation. Based on the information NESCAUM has assembled to date, vigorous enforcement of the BART program could lead to substantial further reductions in key haze precursor pollutants, notably of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Such reductions are not only needed to restore pristine visibility conditions in Class I areas, they would provide major regional benefits in terms of protecting public health and vital natural resources.

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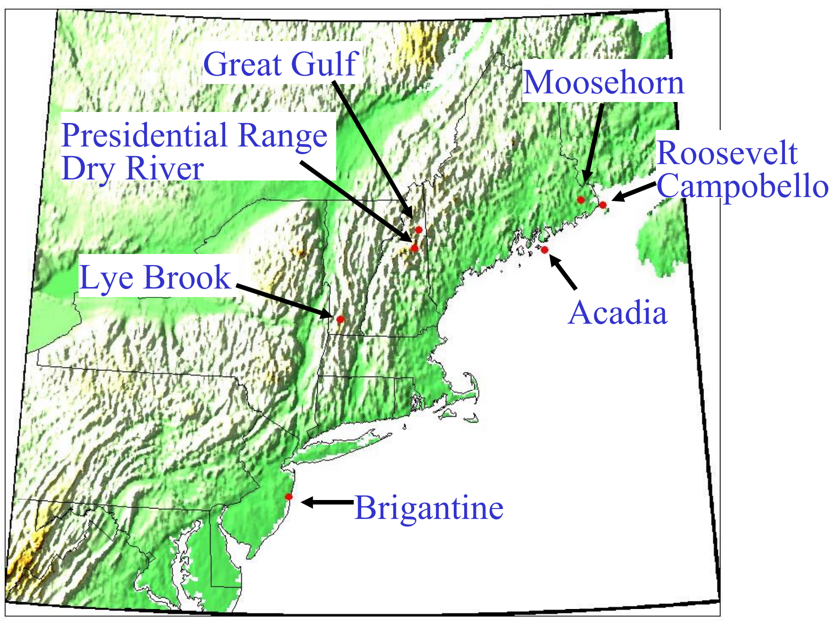
II. Regional Haze and Visibility Impairment in the Northeast and Mid-Atlantic U.S.

This chapter summarizes available information on the scope and nature of existing visibility impairment in the Northeast and Mid-Atlantic States. As noted in the Introduction, much of the information presented here is taken from an earlier and considerably more detailed NESCAUM study titled *Regional Haze and Visibility in the Northeast and Mid-Atlantic States*.[16] The earlier report describes the seven designated Class I areas in the Northeast and Mid-Atlantic States – ranging from the Brigantine Wilderness Area in New Jersey to Roosevelt-Campobello International Park in Maine – and covers more technical aspects of the haze issue such as atmospheric chemistry, modeling and monitoring, etc. (NESCAUM, 2001). Key findings concerning the causes and extent of visibility impairment throughout the region are summarized here to provide context for the discussion of emissions reduction opportunities in subsequent chapters.

Figure II-1: Class I areas in the Northeast and Mid-Atlantic region

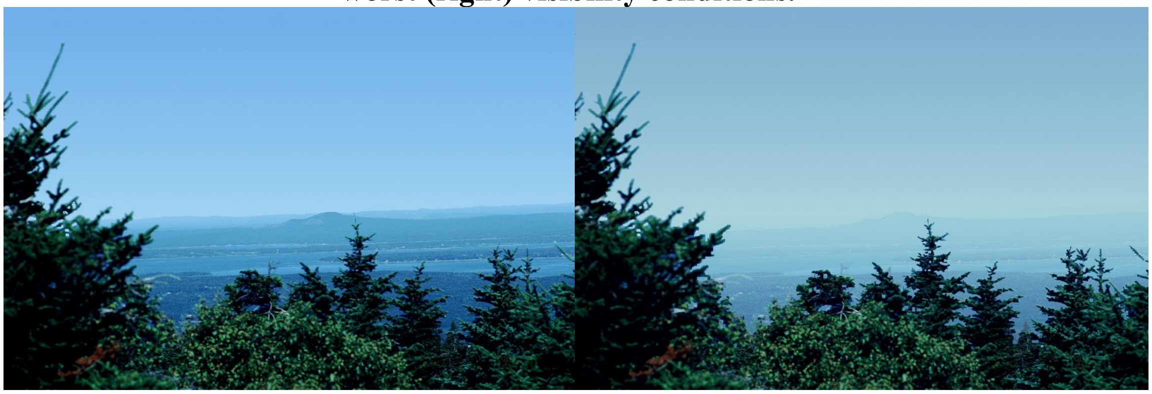


A. How Haze Affects the View

Visibility impairment, or haze, results when small particles and certain gaseous molecules suspended in the atmosphere scatter or absorb visible light. Figure II-2 shows the effect of haze on a scenic vista in the Northeast, simulating the effect of high pollution levels in diminishing the contrast between distant features and the visible sky. This effect occurs to some extent even under natural conditions, primarily as a result of the light scattering effect of individual air molecules (known as

[16] The report, which was released in January 2001, is available at www.nescaum.org.

Figure II-2: View from Acadia National Park under conditions typical of best (left) and worst (right) visibility conditions.*



* As simulated by the WINHAZE Modeling System (Air Resource Specialists, Inc., Ft. Collins, CO).

Rayleigh scattering[17]) and of naturally occurring aerosols.[18] The visibility impairment commonly caused by manmade pollution, however, is almost entirely attributable to the increased presence of very small particles in the atmosphere.[19]

Figure II-3 presents a simplified schematic of the way such small particles interact with packets of light or "photons" as they travel from a distant object to an observer. Along the way, particles suspended in the air can deflect photons out of the sight path, or absorb them; they can also scatter extraneous light *into* the sight path, further diminishing the quality of the view and reducing the amount of useful visual information that reaches the observer. When the combination of light absorption and light scattering (both in and out of the sight path) occurs in many directions due to the ubiquitous presence of small particles in the atmosphere, the result is commonly described as "haze."

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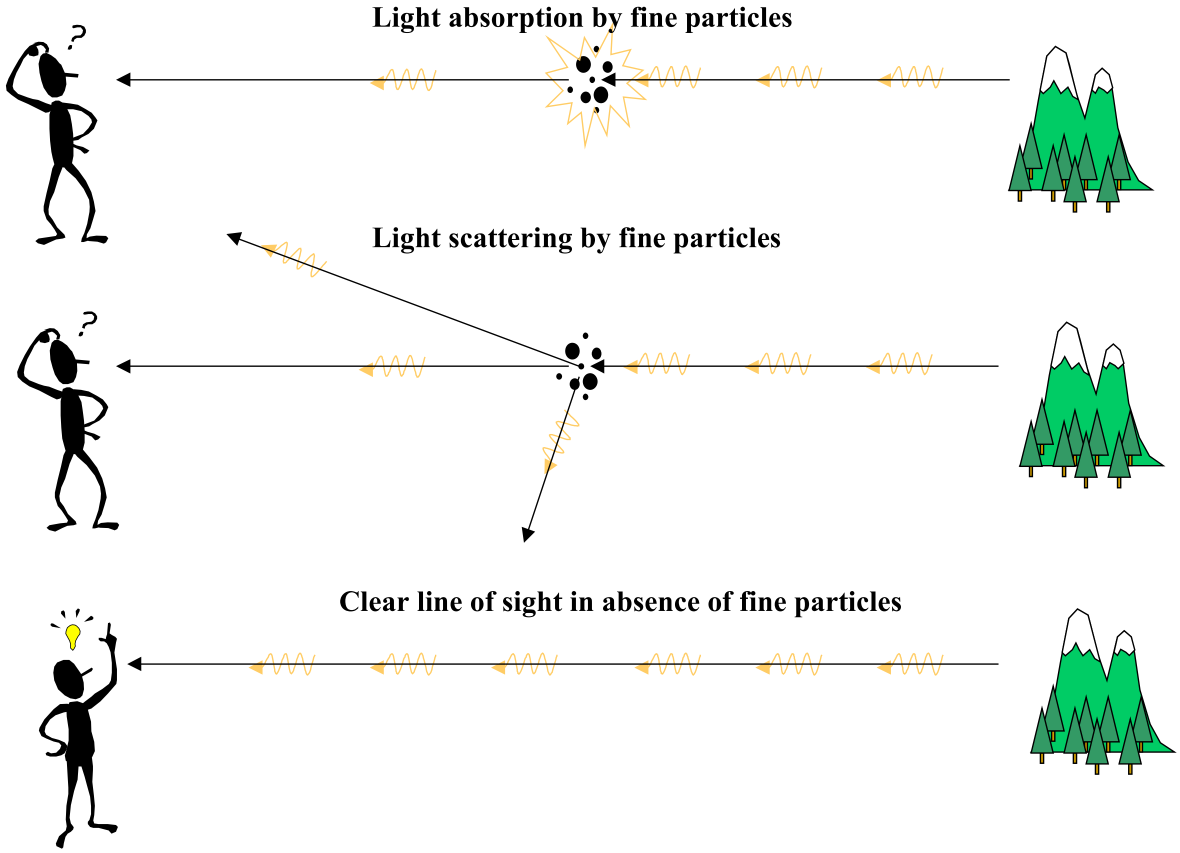
[17] Because air molecules more effectively scatter light of short wavelengths (i.e. blue light), Rayleigh scattering explains the blue color of the sky.
[18] Atmospheric aerosol is a more general term for airborne fine particles that refers to any particles (solid or liquid) which are suspended in the atmosphere. "Fine particles" refers to those aerosol components with a diameter $\leq 2.5\mu m$.
[19] The only light-absorbing *gaseous* pollutant present in the atmosphere at significant concentrations is nitrogen dioxide (NO_2) (USEPA, 1997; Seinfeld and Pandis, 1998). However, the contribution of NO_2 to overall visibility impacts in the Northeast is negligible and hence its effects are not generally included in this discussion or in standard calculations of visibility impairment (FLAG, 1999).

Figure II-3: Schematic of visibility impairment due to light scattering and absorption.



B. Causes of Haze in the Northeast and Mid-Atlantic Region

The fine particles that impair visibility and contribute to haze in the eastern U.S. are formed from pollutants that are emitted by a large variety of sources. Primary constituents of fine particle pollution include:

- sulfates,
- nitrates,
- organic carbon,
- elemental carbon,
- crustal material.

With the exception of elemental carbon – which contributes to visibility impairment chiefly by absorbing light – all of these constituents affect visibility by scattering light (see Table II-1).[20]

Particles are often characterized as either "primary," meaning that they are directly emitted from a pollution source, or "secondary," meaning that they are formed in the atmosphere from

[20] As noted previously, nitrogen dioxide is a gaseous, manmade pollutant that can also absorb light. However, its visibility impacts are not generally significant on a regional scale (see Footnote 19).

precursor emissions. Elemental carbon or soot is emitted directly from diesel combustion and other sources and is an example of a primary particle. Sulfates and nitrates are formed in the atmosphere from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X), respectively and are examples of secondary particles. Particles may exist as liquids or solids and may be composed of a mixture of the different chemical species listed above. To complicate matters further, the light scattering properties of particles vary depending on their specific composition, geometry and size. Particles that are hygroscopic (i.e. readily absorb water), such as sulfate and nitrate, tend to contribute disproportionately to visibility impairment because they grow quickly – especially in the presence of humidity – to the optimal size for scattering light (0.1 to 1.0 micron[21]).

Table II-1 summarizes manmade and natural sources of fine particles and their precursors, together with the non-visibility environmental and public health effects of these pollutants. Dominant sources of the sulfate precursor SO_2 in the eastern U.S. involve fossil fuel combustion, primarily at coal-fired power plants and industrial boilers. Similarly, chief emitters of the nitrate precursor NO_X include power plants, mobile sources, industrial boilers and other combustion sources. While human sources account for most NO_X in the atmosphere, there are some natural sources of this pollutant, including lightning, biological and abiological processes in soils,[22] and stratospheric intrusion (USEPA, 2000). Organic carbon in the atmosphere is emitted by automobiles, trucks, non-road equipment and industrial processes, as well by many types of vegetation.[23] Elemental carbon (soot) is primarily caused by the combustion of diesel, wood and other fuels. Crustal material may include soil, salt, rock and other material[24] and has both natural and manmade sources (examples of the latter include soil dust from roads, construction and agriculture).

Fine particles and their precursors are associated with a variety of negative environmental and public health impacts, apart from their deleterious effects on visibility. Sulfate and nitrate in the atmosphere lead to acid deposition which is damaging to forests and aquatic ecosystems; NO_X emissions contribute to soil nitrification and the eutrophication of sensitive waterbodies; NO_X and organic compounds are together the key ingredients of ozone smog; and fine particle pollution generally has been linked to a variety of serious public health risks – including excess morbidity and mortality from cardiac and respiratory ailments – as well as climate impacts.[25]

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[21] One micron or micrometer (μm) is equivalent to one-one millionth of a meter (10^{-6}m), about the size of one hundred molecules laid end-to-end. Note that the 0.1-1.0 micron size range for optimal light scattering efficiency is within the 2.5 micron size designation used to distinguish fine particles ($PM_{2.5}$) from coarse particles (PM_{10}) in recent federal regulations to limit the health impacts of particle pollution.

[22] Note that soil processes may be substantially influenced by fertilizer use, thereby creating another potential man-made source of emissions.

[23] Unlike elemental carbon, organic carbon is bound to hydrogen and other atoms in more complex molecules. The term organic carbon encompasses literally hundreds of species of such molecules.

[24] A better understanding of crustal material and soil dust, which are likely to vary in composition throughout the U.S., is needed. This class of particles may include silicon, aluminum, iron, calcium, magnesium, sodium, potassium, titanium, manganese, chromium, vanadium, iron and cobalt constituents. Generally, soil dust has lower concentrations of calcium, magnesium and sodium than crustal rock (Seinfeld and Pandis, 1998) and is of greater concern with respect to visibility impacts in the western U.S.

[25] Particles in the atmosphere are known to play a significant role in offsetting or "masking" the greenhouse effect by reflecting sunlight directly and increasing cloud formation. In addition, a recent study by Prinn, et al. (2001) suggests that fine particle pollution may possibly play a role in enhancing the climate-altering potency of greenhouse gases.

Table II-1: Principal components of light impairing particles in the atmosphere.
(adapted from NESCAUM, 2001)

Scattering Components	Primary Sources	Other Environmental and Health Effects
Sulfate	Fossil-fuel combustion (notably at coal-fired power plants and some industrial sources such as metal smelters)	Causes acid deposition, respiratory ailments
Organic Compounds	Gasoline and diesel engines, meat cooking, paved road dust, natural gas combustion, biogenic emissions, petroleum processing, paint and coating operations	Enhance formation of ground-level ozone, many are also toxic
Nitrate	Fossil-fuel combustion (notably by mobile sources and power plants), aircraft, soil	Contributes to acid deposition, irritates eyes and lungs, causes eutrophication and nitrogen saturation, enhances formation of ground-level ozone
Crustal Material (Dust)	Unpaved road dust, agriculture	Respiratory effects
Absorbing Components	**Primary Sources**	**Other Environmental and Health Effects**
Elemental Carbon Particulate	Wood combustion, diesel engines, wildfires	Potentially toxic, carcinogenic

Particulate pollution is directly targeted under existing and proposed air quality regulations. To date, however, these regulations provide for the control of ambient particle levels only on the basis of particle size and mass concentration, i.e. without distinguishing between types of particles. As such, they do not account for the differential light-impairing effects of different particle types.

C. Particle Composition and Extinction Characteristics in the Northeast and Mid-Atlantic Region

Figure II-4 shows visibility impairment at Northeast and Mid-Atlantic Class I sites on the 20 percent most and least impaired days in 1997,[26] as measured by total atmospheric light extinction in units of inverse megameters (or Mm^{-1}).[27] Measurements for an additional urban site in Washington D.C. are included for comparative purposes. Each stacked bar also shows the relative contribution of different particle constituents to overall light extinction. The data used to generate this figure were collected by the IMPROVE (Interagency Monitoring of Protected Visual Environments) program, one of the longest-running visibility monitoring programs in the U.S.[28]

As is evident from Figure II-4, visibility impairment is generally higher in the southern and western portions of the region, which are closer to heavily industrialized areas and population centers. However, it is also apparent that significant visibility impairment occurs on the haziest 20 percent of days even in the most remote, northerly parts of the region. As discussed at more length in Chapter IV, this is almost certainly due to the long-range transport of pollution from upwind regions to the south and west. Overall, the light extinction values shown in Figure II-4 for the 20 percent most impaired days translate to a visual range[29] of 21 kilometers at Brigantine in New Jersey and 41 kilometers at the Moosehorn Wilderness Area in Maine.[30] Averaging over an entire year, the typical visual ranges at these same sites are 37 and 72 kilometers (105 and 54 Mm^{-1}), respectively. By comparison, average visibility for the region absent manmade pollution (i.e. under pristine conditions) has been estimated at 163 kilometers (24 Mm^{-1}) for both sites.

The most striking feature of Figure II-4 is the dominant role of sulfate, which accounts for anywhere from 70 to 82 percent of the non-Rayleigh contribution to overall light extinction on the 20 percent haziest days at all the sites shown.[31] Even on the 20 percent clearest days, sulfate accounts for a large fraction (typically over half) of total fine particle-related light extinction at all sites except Great Gulf, New Hampshire.[32] On hazy days at rural sites, organic carbon consistently

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[26] The terms "worst" or "best" visibility as well as "20 percent worst" or "20 percent best" visibility conditions are defined throughout this report as the simple average of the upper or lower 20 percentile of a cumulative frequency distribution of available data, respectively.

[27] An inverse megameter is equal to one one-millionth of a meter and is a measure of light reduction per unit distance. Light extinction is a direct function of ambient pollution levels and relative humidity. The relationship between Mm^{-1} and other units used to measure visibility (including visual range and deciviews) is discussed in detail in the earlier NESCAUM report (NESCAUM, 2001).

[28] Data available from IMPROVE and other monitoring programs are discussed in detail in the earlier NESCAUM report, which also describes the methodologies used to group hazy versus clear days and to calculate speciated values for light extinction from different particle constituents.

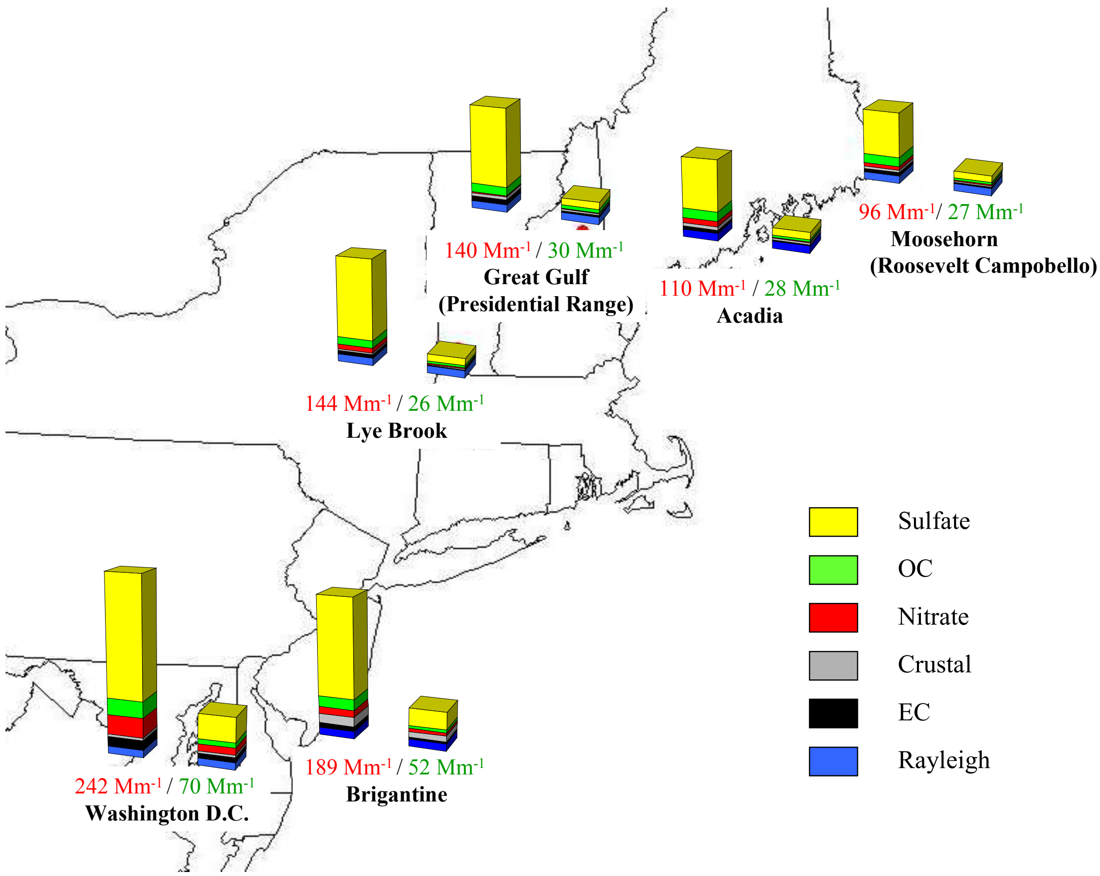
[29] Visual range is inversely proportionate to light extinction and represents the farthest distance at which the human eye can distinguish a dark object against a light horizon.

[30] Note that values shown in the Figure II-4 reflect total atmospheric light extinction, which includes a contribution from natural Rayleigh scattering due to air molecules. Rayleigh scattering typically contributes 10-12 Mm^{-1} to total extinction.

[31] On a *mass* basis, sulfate accounts for anywhere from one-half to two thirds of total fine particle mass on the most impaired days at Northeast and Mid-Atlantic sites. By comparison, organic carbon typically accounts from 20-30 percent of total fine particle mass on the haziest days; while nitrate, elemental carbon and crustal material generally contribute less than 10 percent on a mass basis.

[32] As detailed further in the previous NESCAUM report, only summer monitoring data are available for the Great Gulf site. This may explain the unusually high contribution of organic carbon to total light extinction on the 20 percent

Figure II-4: Speciated contribution to total atmospheric light extinction in or near Class I areas in the Northeast and Mid-Atlantic states on days with the 20 percent worst (left bar) and 20 percent best (right bar) visibility.



accounts for the next largest fraction of manmade visibility impairment, followed by nitrate. The exception is Washington D.C. where the nitrate contribution is greater than that of organic carbon, possibly reflecting the greater importance of combustion-related NO_X sources relative to biogenic emissions in urban versus rural settings.

Notably, crustal material plays a relatively more significant role on the clearest days (especially at the Brigantine and Acadia sites), a result that may be due in part to the inclusion of coarse particles in this category. The relative contribution of elemental carbon and nitrate on the 20 percent clearest days is generally smaller at the rural sites, but varies from location to location.

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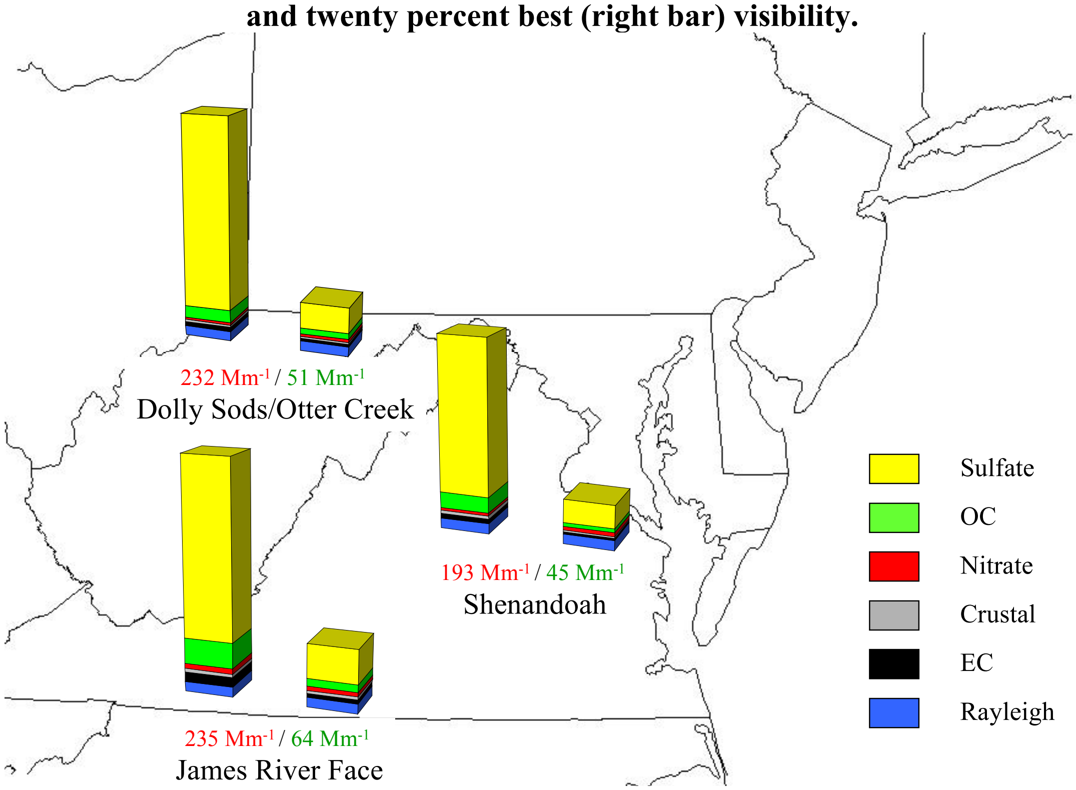
clearest days at this site. At other sites, the 20 percent clearest days probably include a number of winter days, when the contribution of organics – particularly from biogenic sources – would be considerably lower than during the summer months. A comparison to summer data from the nearby Lye Brook site tends to confirm this hypothesis. On the 20 percent least impaired summer days at Lye Brook, relative mass concentrations for organic carbons were almost identical to those found at Great Gulf, suggesting that hydrocarbons (a substantial portion of which may be biogenic in origin) contribute up to half of fine particle mass at rural sites on clear summer days in the region.

D. Particle Composition and Extinction Characteristics in Nearby Regions

Available monitoring data indicate that the causes of poor visibility in the Northeast/Mid-Atlantic region – including the dominant role played by sulfate – are common to much of the eastern U.S. Figure II-5 describes visibility impairment at Class I areas just to the south and west of the MANE-VU RPO, including Shenandoah National Park and James River Face Wilderness Area in Virginia and the Dolly Sods and Otter Creek Wilderness Areas in West Virginia.[33] (Note that there are no Class I areas to the immediate west in Ohio, Michigan, or Indiana.) As the figure shows, visibility impairment at Class I areas just to the south and west of the MANE-VU RPO region is even higher than at Class I areas within Northeast and Mid-Atlantic region. The relative contribution of various particle constituents is somewhat different but follows the same general pattern, with sulfate contributing approximately 85 and 65 percent of total particle extinction on the worst and best visibility days respectively, and organic carbon contributing the next largest fraction (at between 6 and 16 percent of total particle extinction).

Figure II-5: Speciated contribution to total extinction in or near Class I areas just south of the MANE-VU RPO region on days with the twenty percent worst (left bar) and twenty percent best (right bar) visibility.



[33] Note that the maps are based on monitoring data from three IMPROVE sites and were generated using the same methodology used to generate Figure II-4.

E. Measuring Visibility Gains: The Deciview and Its Policy Implications

As noted earlier in this chapter, light extinction (in units of Mm^{-1}) and visual range are commonly used to indicate visibility conditions at a given location and point in time (see footnotes 27 and 29). A third, mathematically related measure known as the deciview (dv) is useful for expressing changes in visibility over time. The deciview is designed on a logarithmic scale to account for the fact that background conditions affect human perception of visibility changes. Specifically, people tend to perceive such changes more readily when the view is relatively unimpaired; they are less sensitive to an equivalent change in visibility when conditions are hazier to begin with. In terms of visual range, a *5 km* improvement in visibility on a day with 55 km visibility conditions (20dv) is perceived the same as a *25 km* difference in visibility on a day with 250km visibility conditions (about 5 dv). We perceive a much larger change in visibility on clearer days. The deciview scale accounts for this nuance, creating a linear correspondence between visibility changes and human perception. Thus, a one deciview change in visibility is just perceptible to most human observers, regardless of initial visibility conditions.

The fact that USEPA requires states and regions to use the deciview measure in tracking their progress toward national visibility goals has important implications for future control strategies. Because much of the eastern U.S. starts from a baseline of substantial visibility impairment (particularly on the 20 percent haziest days), relatively larger reductions in ambient pollution levels may be necessary in the earlier years of the regional haze program to achieve a deciview of improvement in visibility conditions. Conversely, as visibility conditions improve, progressively smaller pollution reductions will be needed to achieve each successive deciview of improvement. Figures II-6 and II-7 show this result graphically by plotting the changes in ambient particle mass concentrations that would be needed to produce linear progress (as measured in deciviews) toward the 2064 "pristine" visibility goal for Acadia National Park and Brigantine Wilderness Area. Estimated baseline conditions are shown by the red triangles at left, which correspond to measured visibility conditions at Acadia between 1988 and 1998 and Brigantine between 1993 and 1988.[34] The graph indicates that a greater portion of needed pollution reductions will have to occur in the early years of the regional haze program to begin making perceptible progress toward longer-term visibility goals. This may also explain why pollutant reductions to date – including, most notably, the SO_2 reductions already achieved under the first phase of the Acid Rain Program – have not contributed more dramatically to measured visibility improvement in the eastern U.S. over the last decade.

[34] See NESCAUM, 2001 for the derivation of estimated baseline and natural visibility conditions for each of the seven Class I areas in the Mid-Atlantic and Northeast region.

Figure II-6: Particle mass goals for Acadia National Park assuming linear decrease in visibility impairment between 2011 and 2064.

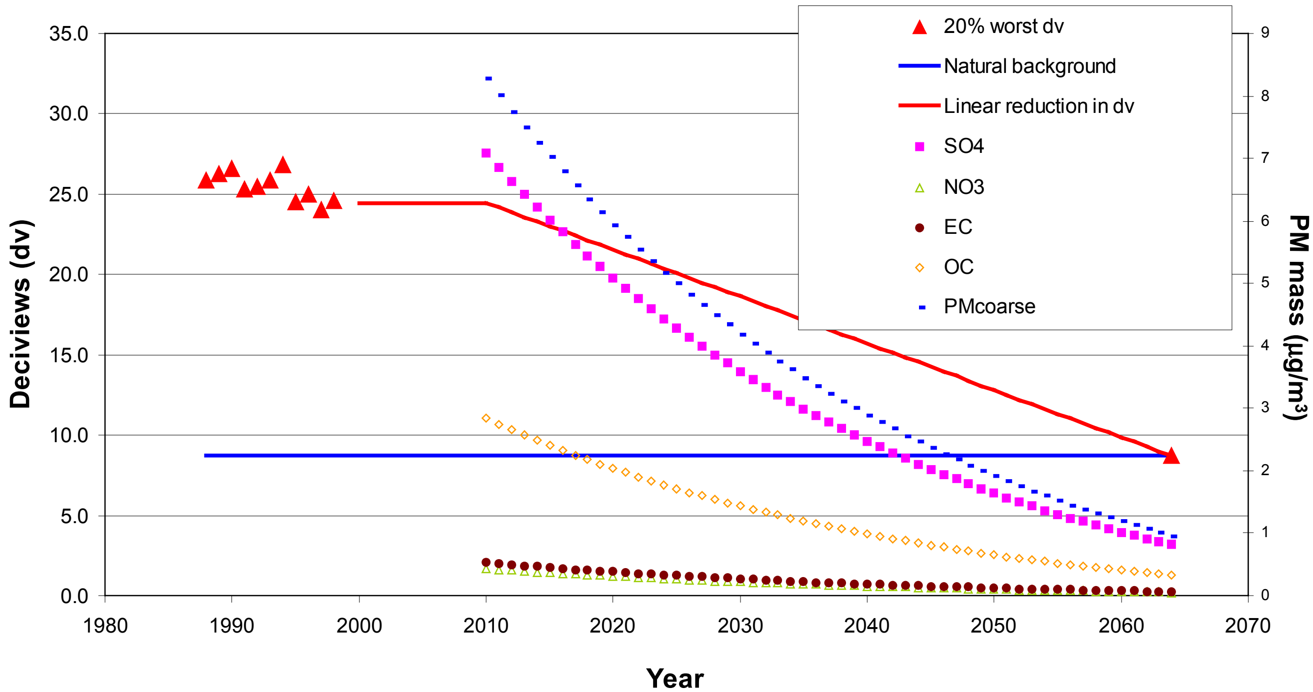
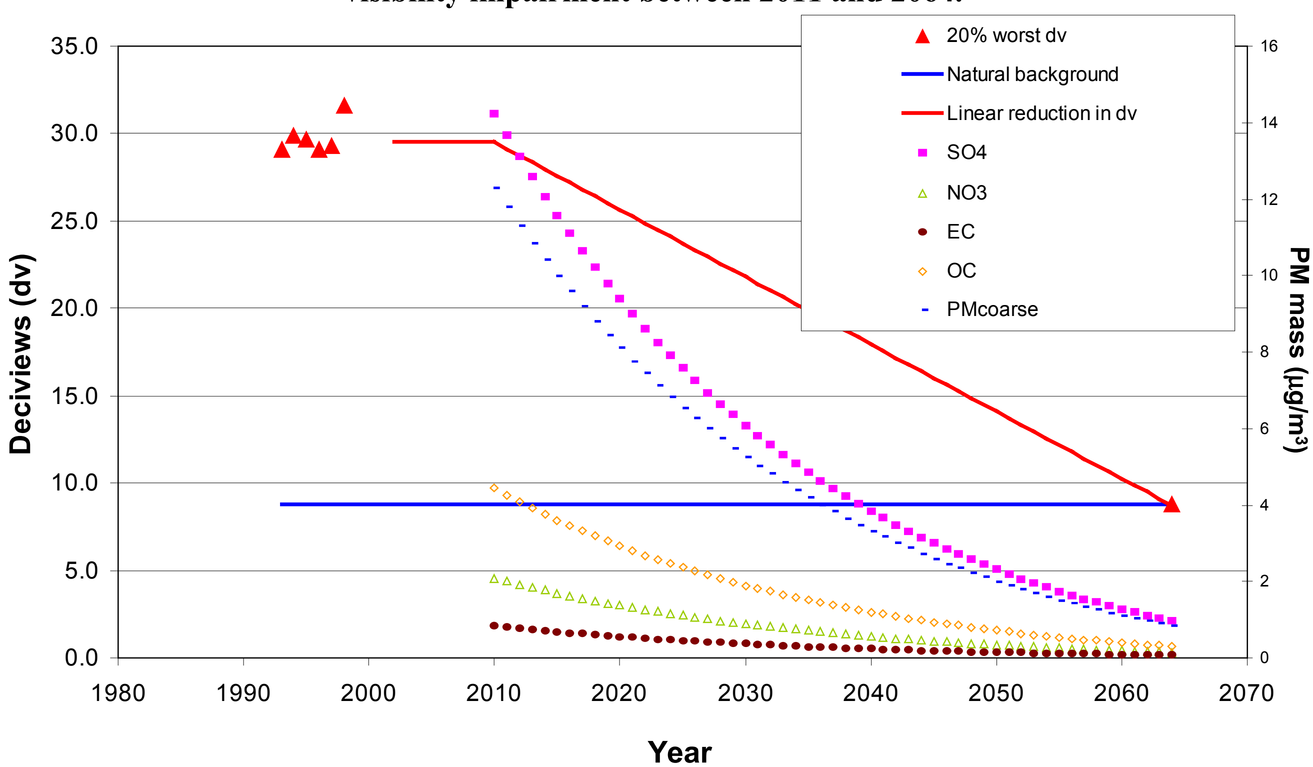


Figure II-7: Particle mass goals for Brigantine Wilderness Area assuming linear decrease in visibility impairment between 2011 and 2064.



Notes: First implementation period for visibility SIPs will be from approximately 2009-2014. Estimates of natural background conditions shown in this report may change after review of forthcoming EPA guidance on the subject.

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III. Best Available Retrofit Technology (BART) Requirements in the Regional Haze Program

Best Available Retrofit Technology (BART) requirements are a core component of the federal regional haze program and are likely to provide the primary basis for implementing substantial pollution reductions to advance visibility goals over the next decade. Before proceeding to a discussion of haze pollutant source regions and emissions reduction opportunities in Chapters IV and V, this Chapter reviews statutory BART requirements as outlined in the CAA Amendments of 1977 and subsequently updated by USEPA in the regional haze rule of 1999 and in more recent guidance published on July 20 (USEPA, 2001).

A. BART Applicability

Under section 169A(b)(2)(A) of the CAA, states must require major stationary sources that may "reasonably be anticipated to cause or contribute to any impairment of visibility" in any Class I area to install BART. BART applicability is limited to the following 26 specific source categories:

(1) Fossil-fuel fired steam electric plants of more than 250 million Btu/hour heat input
(2) Coal cleaning plants (thermal dryers)
(3) Kraft pulp mills
(4) Portland cement plants
(5) Primary zinc smelters
(6) Iron and steel mill plants
(7) Primary aluminum ore reduction plants
(8) Primary copper smelters
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day
(10) Hydrofluoric, sulfuric, and nitric acid plants
(11) Petroleum refineries
(12) Lime plants
(13) Phosphate rock processing plants
(14) Coke oven batteries
(15) Sulfur recovery plants
(16) Carbon black plants (furnace process)
(17) Primary lead smelters
(18) Fuel conversion plants
(19) Sintering plants
(20) Secondary metal production facilities
(21) Chemical process plants
(22) Fossil-fuel boilers of more than 250 million Btu/hour heat input
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels
(24) Taconite ore processing facilities
(25) Glass fiber processing plants
(26) Charcoal production facilities

Applicability is further limited to sources within these categories that have the potential to emit 250 tons per year or more of any haze-causing pollutant and that began operation between

August 7, 1962 and August 7, 1977 (the fifteen years prior to the effective date of the 1977 CAA Amendments). Sources that began operation before August 7, 1962 or came into existence after August 7, 1977 are not subject to BART requirements.

B. BART Provisions in the 1999 Regional Haze Rule

As part of its 1999 regional haze rule [64 Fed. Reg. 35714 (July 1, 1999)], USEPA updated and clarified existing BART provisions in the CAA and existing haze regulations. Initial regional haze state implementation plan (SIP) submittals (due in 2004 or 2005) must include a list of all BART-eligible sources within the state, an inventory of the haze-related pollutant emissions from these sources, and proposed emissions limits (BART determinations for each source) and compliance schedules. Importantly, the obligation to develop SIPs and to impose BART requirements extends, under the 1999 rule, not only to states with a Class I area within their borders, but to any state that reasonably contributes to visibility impairment at Class I sites in downwind states.

Specific elements of the BART determination process are enumerated under 40 CFR §51.308(e)(1). Essentially, two supporting analyses are required: (1) a technical analysis to determine the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source and (2) an impact analysis to assess the degree of visibility improvement at affected Class I areas expected to result from BART reductions. In the technology analysis, states must consider, for each potentially BART-eligible source:

- Compliance costs,
- Energy and non-air quality environmental impacts,
- Any existing pollution control technology in use at the source,
- The remaining useful life of the source, and
- The degree of visibility improvement that may reasonably be anticipated to result from the imposition of BART.

Once states determine BART and EPA approves a state's SIP, controls must be installed and operated as expeditiously as practicable, but not later than five years after SIP approval. Meanwhile, any source identified as BART-eligible has the option of applying to USEPA for an exemption from BART requirements following the provisions outlined in 40 CFR §51.303(a)(2)-(h).

Finally, states have the option of pursuing an emissions trading program or alternative compliance approach if it can be demonstrated that this will result in greater reasonable progress than a source-by-source application of BART requirements. Section 51.308(e)(2) outlines the elements of such a demonstration.

C. More Recent USEPA BART Guidance

The CAA directs USEPA to publish additional guidance concerning the implementation of federal BART requirements, including guidance on determining BART-eligibility, identifying affected sources and determining appropriate levels of control. Given the alternative compliance options introduced in the 1999 rule, more specific guidance is also needed on the development of trading programs or other mechanisms to implement BART-equivalent pollutant reductions.

In January 2001, USEPA completed proposed guidelines for the interpretation and implementation of BART requirements in the context of the new haze regulations. These guidelines were published with some changes in the Federal Register [66 Fed. Reg., 38108 (July20,2001)] as a proposed rule, initiating a formal rulemaking to clarify current regulations relating to BART. Interested parties have until September 18, 2001 to submit comments on the proposed rulemaking to the docket. The Federal Register notice and the proposed guidelines have been included in as Appendix C of this report.

The proposed BART rule includes: (1) an introduction and overview; (2) identification procedures for BART-eligible sources; (3) procedures for identifying sources subject to BART; (4) engineering analyses of BART control options; (5) cumulative air quality analyses; (6) enforceable limits and compliance dates; and (7) an overview of emissions trading programs. While the proposed rule generally clarifies the intent of existing BART requirements, it contains several new pieces of information that may be of interest to states or tribes, including:

- The “in existence as of August 7, 1977” test is essentially the same thing as the identification of emissions units that were grandfathered from the new source review (NSR) requirements of the 1977 CAA amendments.

- “Visibility impairing pollutants” include sulfur dioxide, nitrogen oxides, particulate matter (PM_{10}),[35] volatile organic compounds and ammonia.

- The “potential to emit 250 tons per year of any visibility-impairing pollutant” test requires that a source have the potential to emit 250 tons per year of any single visibility impairing pollutant. Potential emissions of multiple pollutants cannot be summed to exceed the threshold.

- A BART-eligible source is “reasonably anticipated to cause or contribute” to regional haze if its emissions are released within a geographic region from which visibility-impairing pollutants can be transported to a downwind Class I area.

- States or regional planning organizations must conduct air quality modeling analyses to demonstrate that total emissions from an upwind geographic source region contribute in a non-trivial way to visibility impairment in downwind Class I areas.

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[35] Emissions of PM_{10} include the components of $PM_{2.5}$ as a subset and thus a separate designation for $PM_{2.5}$ as a visibility impairing pollutant was not deemed necessary since any unit exceeding the emissions threshold for $PM_{2.5}$ would automatically exceed the threshold for PM_{10}.

- The recommended steps for a BART engineering analysis are similar to the Best Available Control Technology (BACT) review described in the *New Source Review Workshop Manual* (USEPA, 1990).

- For purposes of BART-eligibility, a source refers to all units at a facility that began operation within the 1962-77 time window. For example, if four units at a facility began operation between 1962 and 1977 and each unit's individual emissions are insufficient to trigger BART, but the sum of their emissions exceeds the 250 ton/year threshold, all four units are considered BART-eligible.

- Once a source is deemed subject to BART, a review must be conducted for each visibility-impairing pollutant emitted at that source and for each emitting unit within the source.

- A BART review must consider all available control technologies, including New Source Performance Standard (NSPS) options. Options more stringent than NSPS controls that are considered technically feasible must be ranked and an impacts assessment must be conducted for each one. The most stringent controls for a facility that are technologically feasible, do not impose unreasonable compliance costs or raise unacceptable energy issues or other non-air quality environmental concerns should be considered BART for that source.

- For utility boiler SO_2 control, USEPA has initially proposed a presumptive BART level of 90 to 95 percent control efficiency as cost-effective and generally achievable.

- Visibility SIPs and supporting air quality analyses must provide for BART controls on <u>all</u> sources subject to BART, unless a demonstration can be provided showing that <u>no</u> controls are justified based on a cumulative visibility impact analysis. Subgroupings of a state or region's BART-eligible population of sources cannot be treated separately for the purposes of the cumulative air quality analysis.

It should be noted that several areas of the proposed guidance require further clarification. For example, the precise definition of what constitutes a "non-trivial" contribution to downwind visibility impairment is likely to be a key issue in future BART determinations. Similarly, the proposed guidance still lacks precise criteria for determining that compliance costs are "unreasonable" or that potential energy or other non-air quality environmental impacts are "unacceptable." These and other issues will need to be addressed through the notice and comment process now that a proposed BART rule has been published in the Federal Register.

References

USEPA, *New Source Review Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft*, United States Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, October, 1990.

USEPA, *Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations*, Federal Register, **66**, 38108 (July 20, 2001), Available online at: http://www.epa.gov/ttn/oarpg/t1/fr_notices/bartrule.pdf, United States Environmental Protection Agency, Washington, D.C., 2001.

IV. Source Regions for Visibility Impairing Pollutants in Northeast and Mid-Atlantic Class I Areas

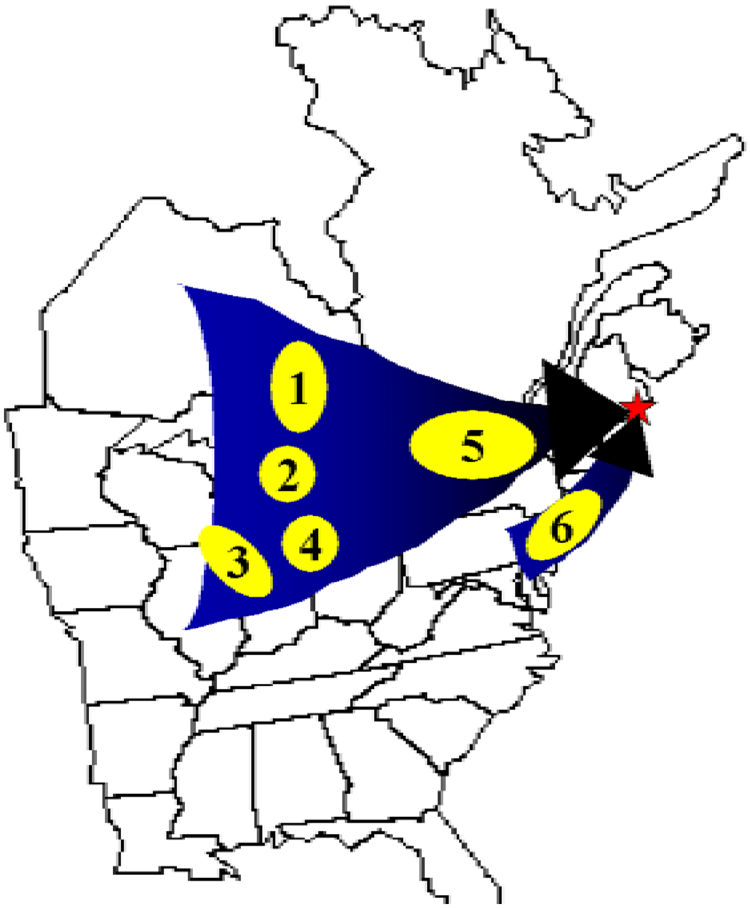
The USEPA guidance described in the preceding chapter establishes that eligible sources will be subject to BART if their emissions are released within a geographic region from which pollutants can be transported to a downwind Class I area. The 1999 regional haze rule further states in its preamble that such geographic source regions may extend for hundreds or thousands of kilometers. A first step in the MANE-VU RPO's regional haze planning efforts will therefore be to establish the geographic source region for pollutants contributing to visibility impairment in Northeast and Mid-Atlantic Class I areas. Fortunately, considerable work has already been done to identify source regions for haze-causing pollutants. This chapter reviews available evidence on the contribution of transported pollution to visibility impairment throughout the region and describes several analytical approaches for defining relevant geographic source regions.

A. The Role of Pollutant Transport

Before summarizing available evidence on source regions for haze pollutants in the Northeast and Mid-Atlantic States, it is useful to review the concept of pollutant transport and its role in haze formation generally. Considerable evidence exists to support the premise that airborne transport of pollutants plays a major role in creating poor visibility conditions throughout much of the eastern U.S. Much of this evidence has been developed in the context of past regulatory efforts to address other regional problems such as acid deposition and ozone smog formation. For example, studies conducted by the National Park Service in the early 1990s indicated that ambient sulfate concentrations at Acadia National Park in Maine were influenced by emissions from as far away as Illinois to the west, North Carolina to the south and Ontario, Canada to the north. Figure IV-1 shows the result of this early analysis, specifying the contribution of pre-1990 SO_2 emissions from different upwind areas on days when sulfate concentrations at Acadia were extremely high (Gebhart and Malm, 1990; Malm, 1992).[36] Though emissions patterns have undoubtedly changed since these studies were conducted, the general finding that distant SO_2 sources have an impact on sulfate levels far downwind remains valid. With an atmospheric lifetime of several days, the ability of SO_2 and sulfate to travel hundreds of miles before leaving the atmosphere has been well documented since at least the acid rain debates of the mid to late-1980s.

[36] "Extreme" was defined as one standard deviation above the geometric mean sulfate concentration. The results shown in Figure IV-1 were generated using so-called "back trajectory analysis," a technique described in later sections of this Chapter. It should be cautioned that the specific results of this early analysis are based on pre-1990 emissions, which do not reflect control programs – such as the Acid Rain Program – introduced later in the 1990s. For example, the large contribution from Sudbury, Ontario identified at that time was due to nickel smelter operations that have since implemented SO_2 reductions of over 80 percent (personal communication, Guy Fenech, Environment Canada). Additionally, this study focused on episodic visibility impairment, while the haze rule addresses the twenty percent worst and best visibility conditions.

Figure IV-1: Pre-1990 source region sulfate contribution to Acadia National Park, ME.
(adapted from Malm, 2000)



1. Sudbury, Ontario 29%
2. Central MI 9%
3. Chicago 5%
4. Toledo 5%
5. Northern NY 24%
6. New York City & Philadelphia 15%
7. Other Sources 13%

Similarly, past studies have pointed to the role of long-range transport in creating high levels of ground-level ozone across large portions of the eastern U.S. during the summer months (e.g. NESCAUM, 1997; CEC, 1997). These studies have demonstrated that severe ozone conditions in the Northeast and Mid-Atlantic states are strongly correlated with meteorological conditions that favor the transport of tropospheric ozone and its precursor pollutants, especially NO_X, from major sources in the industrial Midwest. These and other findings from the extensive air quality modeling conducted by the multi-state Ozone Transport Assessment Group in the late 1990s form the basis of recent federal efforts to require substantial NO_X reductions from power plants and other major industrial sources throughout a broad eastern states region. They are supported by field studies indicating the presence of low-level jets (200-800 meters above ground level) that are capable of transporting pollutant-laden, aged airmasses hundreds of miles up the Northeast corridor (Blumenthal et al., 1997).

Earlier efforts to address ozone and regional haze have yielded the useful concepts of “areas of influence” and “areas of violation” (AOIs and AOVs). The identification of an AOI and assessment of its emissions and relevant meteorology allows for the anticipation of impacts on corresponding AOVs.

Table IV-1: Atmospheric Residence Times of Various Haze Constituents

Visibility Impairing Constituents	Precursor Species and Intermediate Forms	Residence Time[a] of PM precursors and constituent components (days)
Sulfate (gas phase)	SO_2, H2SO4	2.1[b,c],3[d]
Sulfate (aqueous, solid)	SO_4^{2-}, $(NH_4)_2SO_4$, NH_4HSO_4, $(NH_4)_3H(SO_4)_2$	3-20[b]
Nitrate (gas phase)	NO_2, NO, HNO_3	1-4 days[b]
Nitrate (aqueous, solid)	NH_4NO_3, NO_3^-	3-20[b]
Organics (gas phase)	VOCs, non-volatile organics	hours-days[e]
Secondary Organic Aerosol	partially oxidized VOCs, organics	1-20[e]
Primary $PM_{2.5}$	EC, dust, soil, minerals	3-20[b]

Notes:
[a]Atmospheric residence time refers to the time for roughly 2/3 of initial concentrations of a pollutant to be removed. We note that roughly 1/3 of the pollutant will still be present in the atmosphere after this time has elapsed.
[b]Seinfeld and Pandis, 1998.
[C]Assumes that sulfur is present as 50% SO_2 and 50% sulfate.
[d]Schlesinger, 1997.
[e]Finlayson-Pitts and Pitts, 2000.

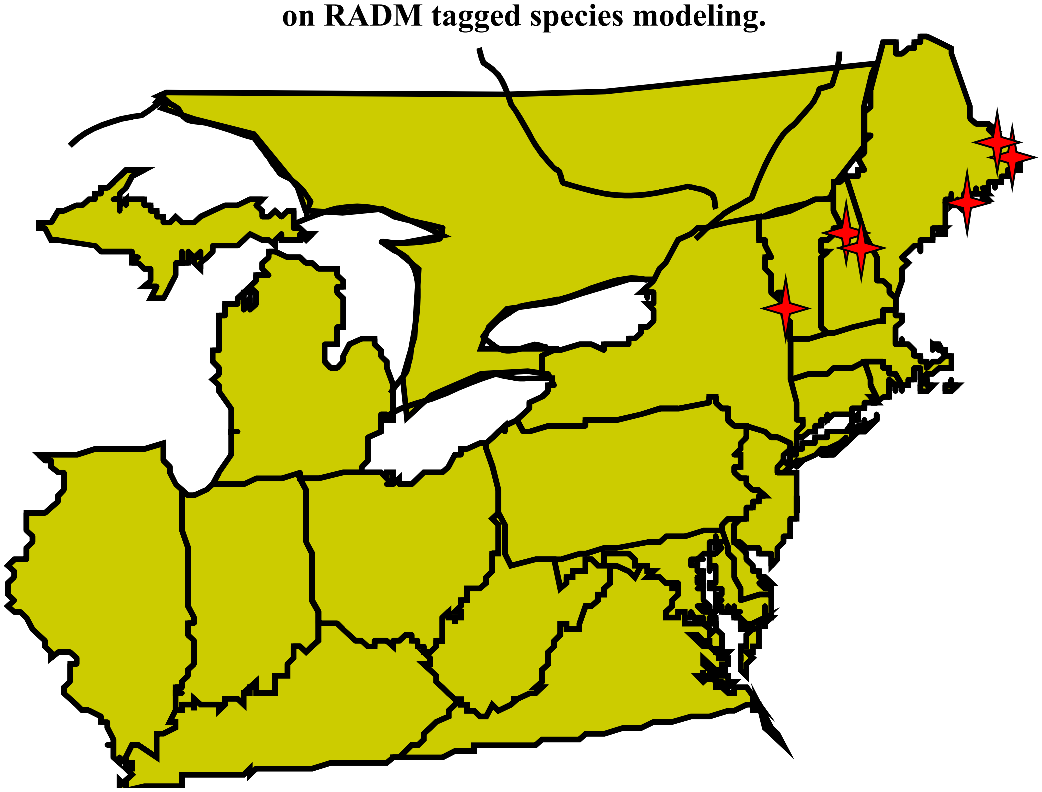
While many past pollution transport studies have focused on acid rain and ozone precursors, the basic transport mechanisms they identify are likely to apply to the full range of visibility impairing pollutants. Table IV-1 shows the atmospheric residence time of key fine particle constituents. As is evident from the table, other haze pollutants – including secondary organic aerosols and primary fine particles – have residence times similar to or longer than those of sulfate and nitrate. Consequently, transport patterns and source regions for these haze pollutants are likely to be similar, given that they are emitted by many of the same urban and industrial sources and given that they are subject to the same (typically west to east) weather patterns.

The next sections of this chapter summarize results from three different types of studies that have been used to identify source regions for visibility impairing pollutants in the Northeast and Mid-Atlantic U.S. The focus of these sections is primarily on sulfate and its precursor SO_2. As described in earlier chapters of this report and in NESCAUM's previous haze study, sulfate is the single most important contributor to fine particle concentrations and visibility impairment at Class I sites throughout the region. In addition, for the reasons discussed above, identified source regions for sulfate are likely to correspond to a considerable extent with source regions for other key haze constituents in the eastern U.S.

B. Results from Sulfate Deposition Studies

Modeling tools designed to predict sulfate deposition can be used to identify source regions for ambient sulfate aerosols and their SO_2 precursors. USEPA used this approach to identify the source region shown in Figure IV-2 for sulfate deposition in New England as part of its 1995 Report to Congress on the feasibility of establishing an acid deposition standard. Specifically, USEPA used the Regional Acid Deposition Model (RADM) to "tag" SO_2 emissions from power plants and large industrial sources in 53 separate subregions of the eastern U.S. and parts of Canada. The tagged emissions from each subregion were then followed through the model's simulation of transport and

Figure IV-2: SO_2 source region (shaded) for sulfate in New England Class I areas based on RADM tagged species modeling.



chemical transformation processes to the point of deposition. The resulting deposition plots (USEPA, 1995, Appendix C) indicate that SO_2 emissions from the broad region shown in Figure IV-2 contribute, in some degree, to sulfate deposition in the New England Class I areas shown in the figure.

NESCAUM has since conducted additional analyses which support USEPA's 1995 findings. One analysis correlates changes in emissions from the source region shown in Figure IV-2 with subsequent trends in sulfate deposition at several New England sites. For purposes of this analysis, only emissions from fossil fuel power plants were considered, since this source category accounts for the great majority of SO_2 emissions reductions achieved between 1980 and 1997.[37] Emissions data were taken from a variety of sources, including various USEPA and Canadian databases.[38] Information on annual sulfate deposition rates from 1980 to 1998 was obtained from the National Atmospheric Deposition Program (NADP) (NADP, 1999). The measures used included precipitation-weighted mean concentrations in milligrams per liter (mg/L) and total deposition in kilograms per hectare (kg/ha). Some years of deposition data for some sites were excluded in cases where the data did not meet the completeness criteria recommended by NADP;[39] in addition, data were not available for all years at every site. Finally, deposition data prior to 1994 were adjusted downward by 2.6 percent to reflect a change in the sample handling procedures used at NADP sites.

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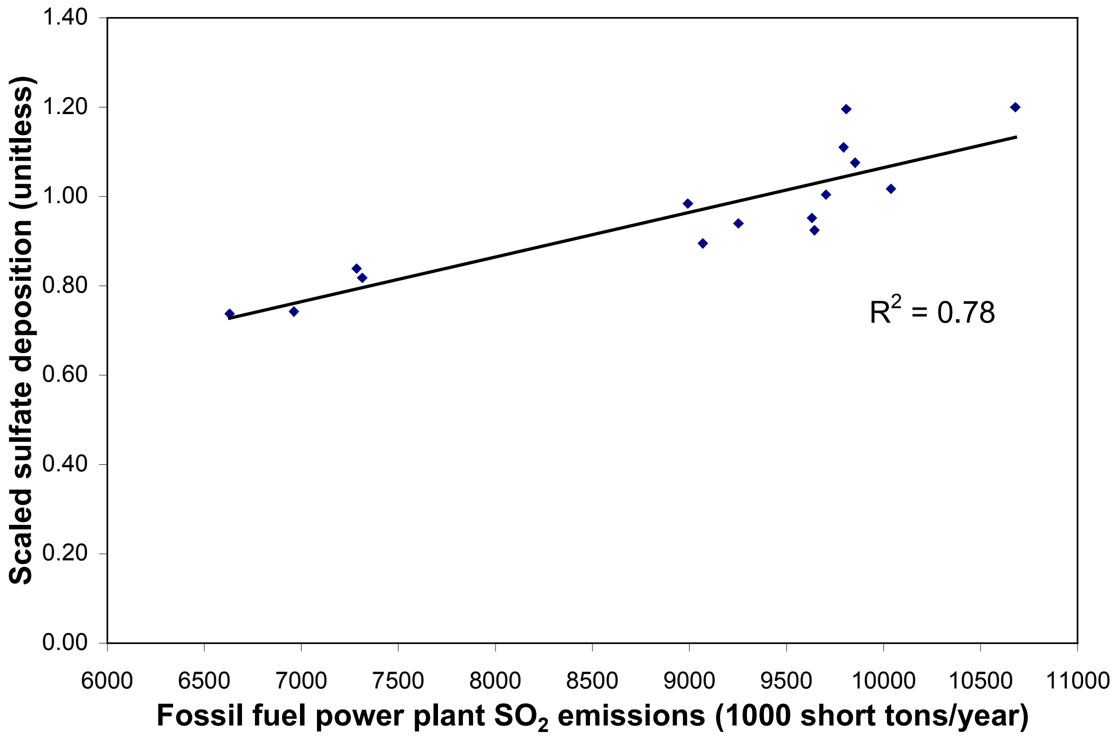
[37] From 1980 to 1997, total U.S. SO_2 emissions decreased from 25,905,000 tons to 20,369,000 tons; a reduction of 21 percent (USEPA NET viewer, 1998). Of the 5,536,000 tons reduced, fossil fuel power plants accounted for 4,387,000 tons, or about 80 percent of the total reduction.

[38] For US emissions from 1985 through 1996, emissions data were taken from the USEPA National Emissions Trends (NET) Viewer, 1985-1996 (USEPA NET viewer, 1998). Emissions for 1980 come from the USEPA Emissions Scorecard 1996 (USEPA, 1997), while emissions data for 1997 and 1998 come from the 1997 and 1998 USEPA Emissions Scorecards, respectively (USEPA, 1998 and USEPA, 1999). The years 1981 through 1984 were excluded because of a lack of state-level utility sector emissions data for those years.

Ontario emissions data come from Environment Canada (1995, 1998) and the Canada-United States Air Quality Agreement Progress Report (1996). Because emissions data for Ontario during the years 1985 to 1987 and 1989 are lacking, they were estimated using a linear extrapolation of emissions data from 1980, 1988 and 1990. Data on Ontario emissions for 1998 were similarly unavailable, hence these were assumed to be comparable to 1997 emissions. The use of these assumptions introduces some uncertainty into the correlation analysis, but the effect is not likely to be significant since Ontario's contribution to the overall regional inventory has declined substantially over the last decade (see Footnote 36).

[39] NADP's four completeness criteria include: (1) fraction of the summary period for which there are valid samples is $\geq$ 74.5 percent; (2) fraction of the summary period for which precipitation amounts are available either from the rain gauge or from the sample volume is $\geq$ 89.5 percent; (3) fraction of the total measured precipitation associated with valid samples is $\geq$ 74.5 percent; and (4) sum of the sample precipitation in the summary period divided by the sum of the rain gauge amounts for all valid samples where both values are available is $\geq$ 74.5 percent (called the collection efficiency).

Figure IV-3: Correlation of fossil fuel power plant SO_2 emissions to combined sulfate precipitation-weighted and total deposition in New England (1980-1998).



Using a method described by Shannon (1999), the annual NADP precipitation-weighted mean concentrations and total sulfate deposition were scaled to a mean of unity for the period 1980 to 1998.[40] The resulting correlation between scaled NADP deposition data and SO_2 emissions from power plants in the identified source region is plotted in Figure IV-3. As is evident from the plot, SO_2 emissions in the source region identified by USEPA in 1995 correlate strongly with sulfate deposition in the New England region.

Note that the source region shown in Figure IV-2 and confirmed by NESCAUM's subsequent correlation analysis is specific to New England sites. A similar approach has been used by Shannon (1999) to investigate the source region for sulfate pollution at the Brigantine Wilderness site in New Jersey. The results of Shannon's analysis of wet sulfate deposition trends at mid-Atlantic NADP sites (in DE, MD, NJ, NY, PA, VA) as well as at several New England sites[41] are shown in Table IV-2. In addition to contributions from sources within the Mid-Atlantic States, Table IV-2 shows significant contributions from sources in the Ohio River Valley as well as in Ontario.

[40] More detail on this approach is given in a NESCAUM report on emissions-related acid deposition trends in Maine and New England (NESCAUM, 1999).
[41] Note that Shannon's results for New England are largely consistent with those obtained by NESCAUM in the analysis discussed previously.

Table IV-2: Importance of emissions within the New England and Mid-Atlantic receptor regions and the most important SO_2 sources (aggregated by state or province) for 1985 emissions. (Shannon, 1999)

Receptor region	Contribution of anthropogenic sources within receptor region to wet sulfate deposition (%)	Five most important anthropogenic sources and their contributions to wet sulfate deposition (%)
New England	4.7	OH (13.9) PA (9.6) Ont (8.0) IN (7.2) WV (6.5)
Mid-Atlantic	17.0	OH (16.7) PA (9.8) IN (8.6) WV (7.5) Ont (5.7)

In sum, available evidence from sulfate deposition studies is generally consistent and suggests a large upwind source region for sulfate pollution in the MANE-VU RPO region (see also Holland et al, 1999).

C. Results from Back Trajectory Analyses

Back trajectory analysis is another useful tool for analyzing source regions for haze and other transport-related pollution phenomena. This approach involves using meteorological data to track the prior "path" of parcels of air arriving at a particular monitoring site over a period of hours or days. By examining dominant air trajectories during the hours and days preceding the measurement of best and worst visibility conditions at Class I sites, source regions influencing those conditions can be identified.

Figures IV-4 through IV-6 show the results of back trajectory analyses conducted for Acadia National Park, Lye Brook Wilderness Area in Vermont, and the Brigantine Wilderness.[42] Back trajectories were calculated from a point 500 meters[43] above each

[42] In all cases back trajectories were calculated using the HYbrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT-4) model developed at the National Oceanic and Atmospheric Administration Air Resources Laboratory (NOAA ARL) (Draxler and Hess, 1997, 1998). Model details are available at http://www.arl.noaa.gov/ready/hysplit4.html. Note that the accuracy of the trajectories is affected by the temporal and spatial resolution of the input meteorological data. NOAA ARL archives analyzed meteorological products for use with the HYSPLIT model including the Eta Data Assimilation System (EDAS) wind fields, which cover North America with an 80 km spatial resolution and are based on 3-hourly variational analyses. Using these spatial and temporal resolutions, the HYSPLIT model has been shown to have a trajectory accuracy of 20-30 percent of the total transport distance (Draxler, 1996, 1991; Stunder, 1996). When EDAS data was unavailable or incomplete, trajectories were calculated using the FNL meteorological data (approximately 190 km spatial resolution). If neither EDAS or FNL data were available, NCEP/NCAR Reanalysis data were used (a description of all NOAA archived meteorological data products can be found at http://www.arl.noaa.gov/ss/transport/archives.html). Case studies (Draxler and Hess, 1998) have also shown that due to large variations of wind speed and direction near the ground relative to higher altitudes, it is essential that the atmosphere's vertical structure be well represented by the input data. It is estimated that the HYSPLIT forecast trajectories have one-third of the relative trajectory

Class I area for 72-hour periods ending at 6:00 AM, 12:00 PM and 6:00 PM on each of the 20 percent worst and best visibility days between 1997 and 1999.[44,45] Note that much of the SO_2 emitted into the path of these trajectories during the 72-hour period preceding best and worst visibility conditions would be likely to contribute to subsequent impairment at the downwind monitoring site, given that the combined atmospheric residence time of SO_2 and its chief product, sulfate, is typically a week or more.

Figures IV-4a and b show that air masses contributing to worst-case visibility conditions in Acadia National Park tend to originate far to the south and west of the Park's boundaries. By comparison, air masses present over the park during the 20 percent of days with the best visibility conditions tended to originate from the north over Canada. For the Lye Brook Wilderness, Figure IV-5a shows back trajectories for the 20 percent worst visibility days clustered over New York State, northwest Pennsylvania, and Ohio as well as along a more southerly route over New York City and New Jersey. By comparison, the best visibility days at Lye Brook (Figure IV-5b) are strongly associated with back trajectories over northern New York State and the Quebec/Ontario border. Unlike the more northern Class I sites, back trajectories for Brigantine (see Figure IV-6) indicate that the worst 20 percent visibility days at that site are associated with air masses coming from further south as well as from the west. Conversely, air masses on the best visibility days at Brigantine seem to originate from all directions *except* the west or southwest. Taken in conjunction with the trajectory work done by the National Park Service in the early 1990s and discussed in Section A of this Chapter, these results provide strong evidence that SO_2 emissions from sources distributed over a large portion of the eastern U.S. and parts of Canada can contribute to poor visibility in Northeast and Mid-Atlantic Class I areas.

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error during low shear conditions than during high shear conditions (Stunder, 1996). It is reasonable to assume that these meteorological conditions would have a similar effect on our back trajectories.

[43] Back trajectory starting height does have an influence on the path a trajectory follows. In this analysis, trajectories were calculated for starting heights 200, 500 and 1000 meters above each site, although the 500 meter trajectories were deemed to be the most representative of the path of air parcels comprising the mixed layer. Trajectories calculated at lower altitudes are subject to interferance from surface features (terrain and buildings), whereas higher altitude trajectories may be above the mixed layer at times and not representative of the air mass which resides in the mixed layer. Based on analysis of climatological mean boundary layer heights in the eastern United States (see Kleiman and Prinn, 2000) 500 meter starting heights were selected as the most reasonable starting height for eastern coastal locations. The major findings of the current report were subjected to a sensitivity analysis using the 200 meter and 1000 meter trajectories. Results of this test indicate that differences of less than 10% are observed in the total SO_2 and NO_X emissions reductions estimated in Chapter V of this report due to differences in trajectory start height.

[44] Meteorological input (EDAS) data were unavailable prior to 1997 and data on monitored visibility conditions were available only through September 1999 at the time of analysis.

[45] Some trajectories could not be calculated for the full 72 hours due to errors in the meteorological input data or in cases where a trajectory went outside the domain for which meteorological data were available. If an error in the meteorological data led to the truncation of a trajectory prior to 48 hours, a complete trajectory was calculated using alternate meteorological input data as described in footnote 42.

Figure IV-4a: Back trajectories on 20% worst visibility days at Acadia National Park during 1997-99.

Figure IV-4b: Back trajectories on 20% best visibility days at Acadia National Park during 1997-99.

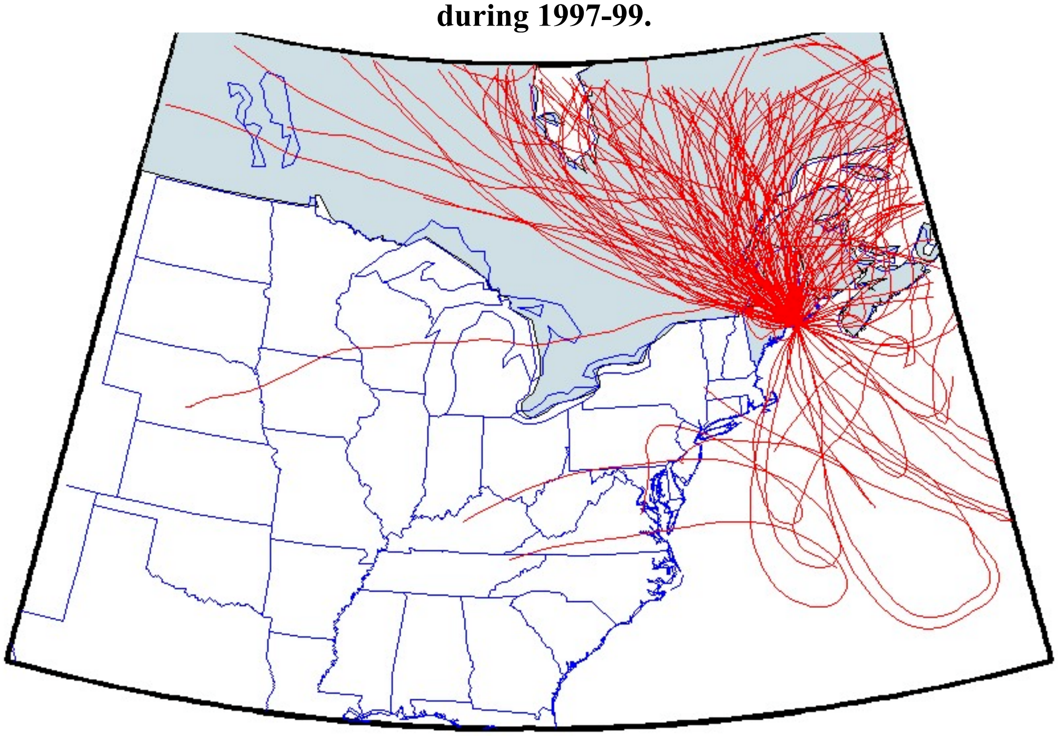


Figure IV-5a: Back trajectories on 20% worst visibility days at Lye Brook Wilderness Area during 1997-99.

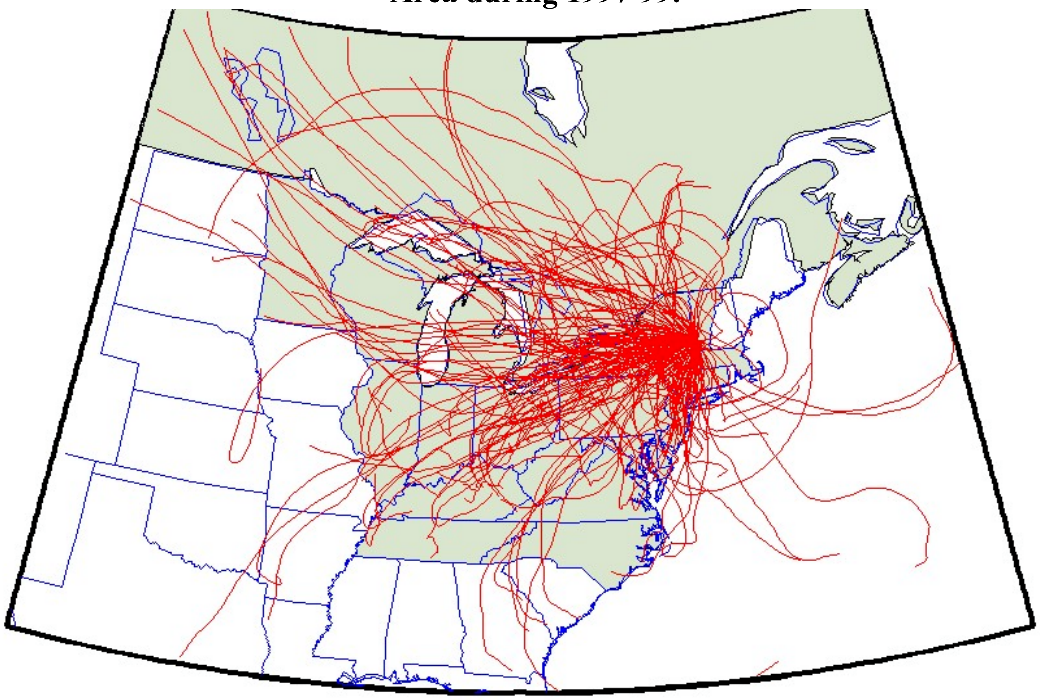


Figure IV-5b: Back trajectories on 20% best visibility days at Lye Brook Wilderness Area during 1997-99.

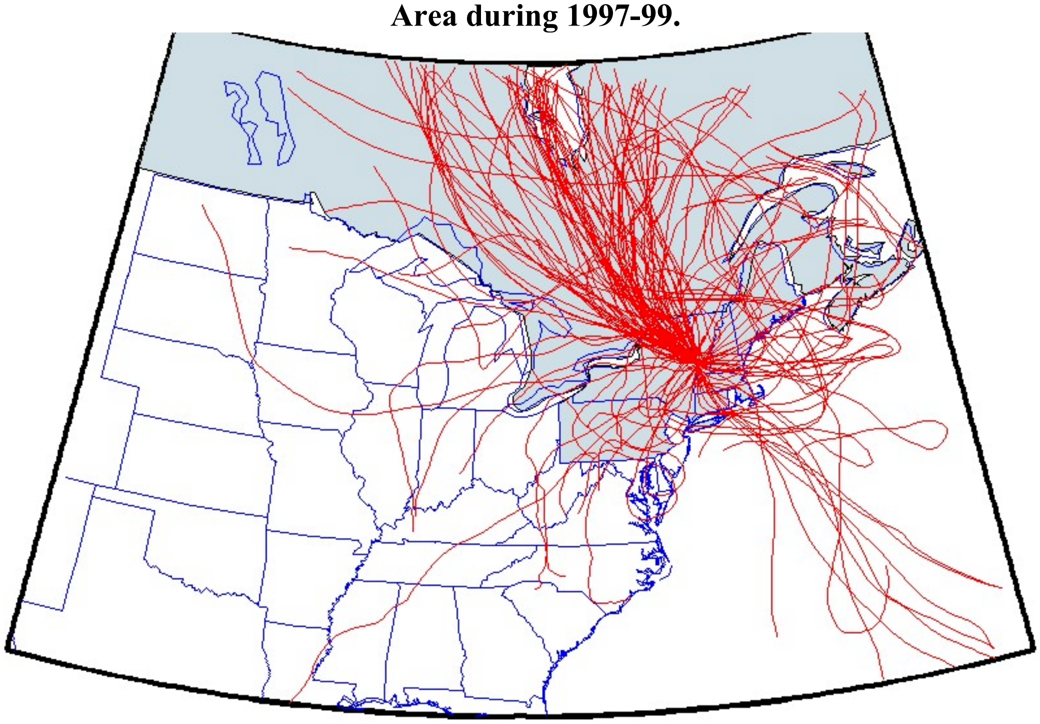


Figure IV-6a: Back trajectories on 20% worst visibility days at Brigantine Wilderness Area during 1997-99.

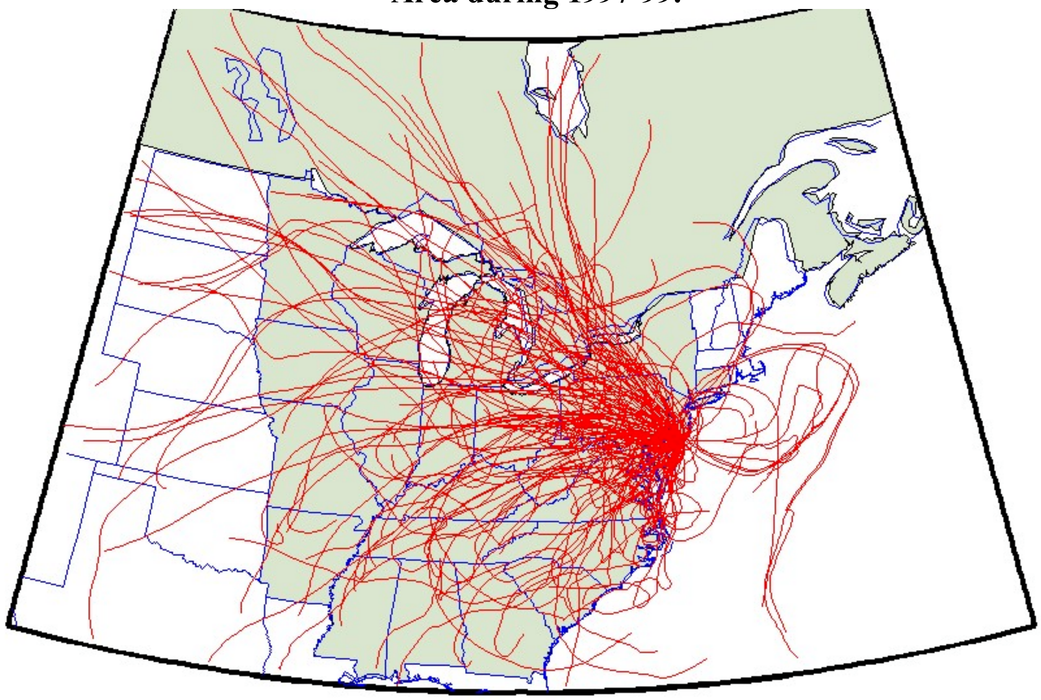


Figure IV-6b: Back trajectories on 20% best visibility days at Brigantine Wilderness Area during 1997-99.

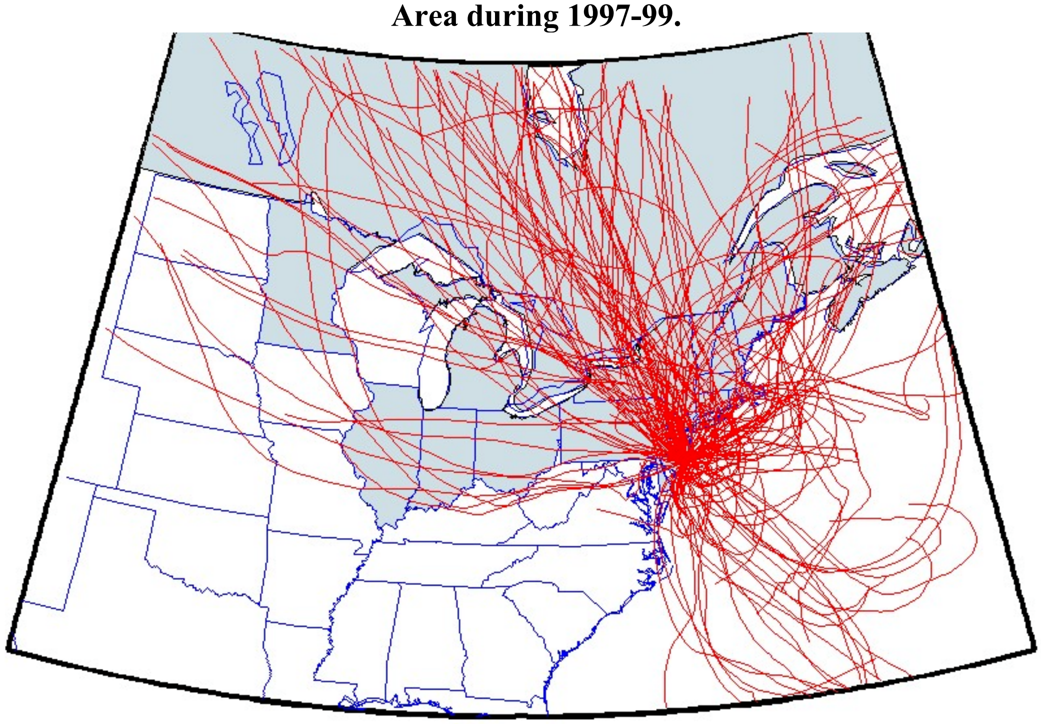
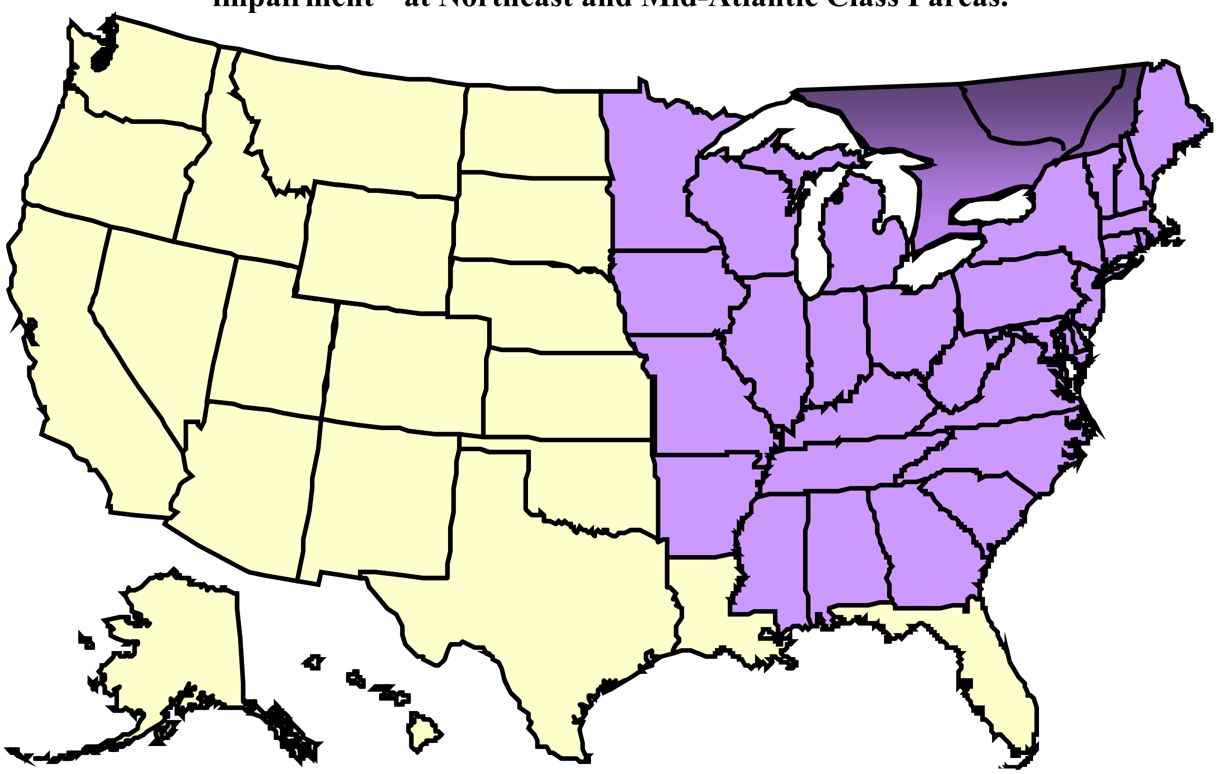


Figure IV-7 shows the probable source region for pollutants contributing to visibility impairment[46] in Northeast and Mid-Atlantic Class I areas based on the back trajectories associated with poor visibility conditions at Brigantine, Lye Brook and Acadia. Each of the 29 states shown in the figure is passed over by at least eight of the back trajectories constructed for the 20 percent haziest days at these sites.[47] Note that the identified region is roughly consistent with that indicated by USEPA's 1995 RADM tagged species modeling runs and with the region subject to further NO_X reductions under recent USEPA actions to address the transport of ozone and ozone precursors.[48] Thus, while the trajectory work and other modeling studies described here should be refined during the MANE-VU RPO planning process, Figure IV-7 provides a preliminary but probably fairly accurate estimate of the likely source region to be included in future visibility-related emissions reductions efforts.

Figure IV-7: Source region reasonably anticipated to cause or contribute to visibility impairment[46] at Northeast and Mid-Atlantic Class I areas.



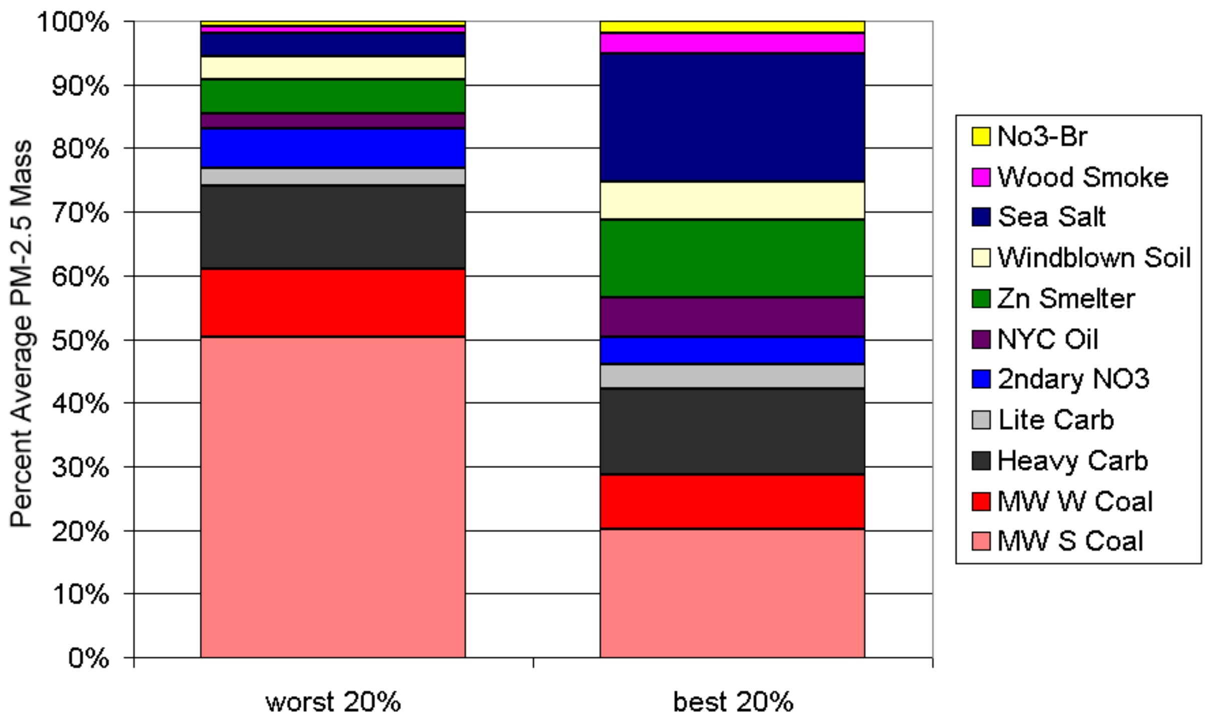
[46] This region addresses visibility impairment on the 20 percent worst days only. A different source region must be considered to address visibility impairment on the 20 percent best days. This region will likely include different regions (e.g. Atlantic provinces of Canada) and may be important in preventing deterioration of current visibility on the 20 percent best days, as called for by the regional haze rule.
[47] Eight trajectories (seven for Lye Brook) represent greater than 5 percent of the available trajectories which were calculated for the 20 percent worst visibility days between 1997 and the end of 1999 (130-150 trajectories per site).
[48] Specifically, USEPA's Section 110 NO_X SIP call (see further discussion in Chapter VI).

D. Results from Source Apportionment Analyses

Source apportionment (or "factor") analyses use the unique chemical profiles of different particle constituents to examine the contribution of specific source categories to ambient particle pollution levels. The results can then be combined with back trajectory techniques to link different particle constituents and their likely emissions sources to specific geographic source regions.

Recently, scientists at the Vermont Department of Environmental Conservation (DEC) have applied this type of analysis to IMPROVE fine particle data from the Brigantine Wilderness Area in New Jersey – the southernmost Class I site in the MANE-VU RPO (Poirot and Wishinski, 2001). As a first step, the components of fine particle samples collected at Brigantine were analyzed and 11 distinct source profiles were calculated.[49] Combined, these source profiles can explain 90 percent of measured fine particle mass at the Brigantine site. In addition, their unique chemical characteristics suggest the likely nature of corresponding emissions source(s), as indicated by the labels

Figure IV-8: Percent fine mass source contributions at Brigantine Wilderness, on high (worst 20%) and low (best 20%) extinction days, 1992-1999.



[49] Using the UNMIX model (Henry, 1997) "source profiles", which consist of a particular combination of fine particle constituents in fixed relative abundances, are calculated such that a linear combination of these source profiles fits with observed measurements of total abundances of each constituent.

preliminarily assigned to each profile (e.g., summer and winter coal combustion,[50] heavy carbon, light carbon, secondary nitrate, oil combustion, zinc smelter, etc.).[51] Figure IV-8 shows the relative mass contribution of particle constituents matching different source profiles on the 20 percent of days with best and worst visibility[52] at the Brigantine site from 1992 to 1999. The results of the analysis point to the significant contribution of coal combustion to observed fine particle mass concentrations at the Brigantine site under both best and worst visibility conditions. The coal contribution is particularly large on the 20 percent worst visibility days when it typically contributes over 60 percent of total fine particle mass.

To identify likely geographic source regions for the different particle constituent source profiles indicated in Figure IV-8, back trajectories[53] were constructed for the 10 percent of days with the highest contribution of fine mass corresponding to each source profile. Researchers at Vermont DEC then analyzed the resulting back trajectories to see whether there was a strong association between particular regions and high downwind levels of distinct particle constituents. Specifically, they examined the probability that back trajectories associated with a given source profile would traverse a particular geographic area. The results of this analysis are shown in Figure IV-9. The area shaded bright red in Figure IV-9 represents all locations that were especially likely[54] to be in the path of air masses arriving at Brigantine on days when the contribution from summer coal at Brigantine was especially high. It is important to emphasize that areas *outside* those shaded in Figure IV-9 may also have a higher than average probability of contributing to the different source profiles identified at Brigantine on hazy days. In other words, the figure should not be read to imply that only those emissions sources located inside the shaded areas are responsible for the presence of corresponding particle constituents at the Brigantine site. These are simply the areas that are *most* likely to be upwind on days when the source contributions are highest.

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[50] The labels "summer coal" and "winter coal" are "short names" which reflect the opposite seasonality of two separate Midwestern regional source profiles identified by the UNMIX model. The key difference between these two source profiles is their different proportions of sulfur (S) and selenium (Se). A low S:Se ratio typically results when there is minimal formation of secondary sulfate during transport (most common during winter). A high S:Se ratio is indicative of efficient conversion of SO_2 to SO_4 during transport (most common during summer). Hence, these "winter" and "summer" coal sources can also be interpreted as approximating the primary and secondary pollutant impacts from a common Midwestern source region.

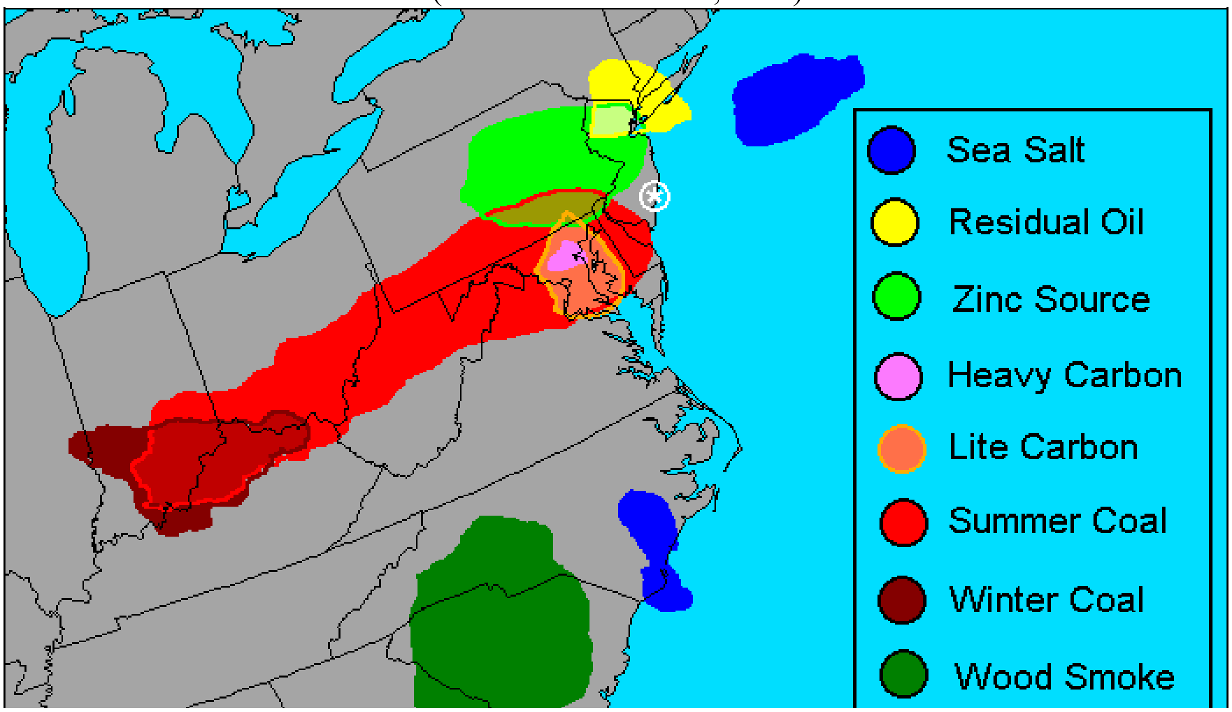
[51] Note that the labels shown in Figure IV-8 are subjective in the sense that a definitive link between identified source profiles and their emissions sources has not yet been established.

[52] As measured by reconstructed light extinction. The methodology used for calculating light extinction from the mass concentrations of different particle constituents is described in the earlier NESCAUM report.

[53] Trajectories calculated by the National Park Service using the ATAD trajectory model (see Gebhart and Malm, 1990).

[54] Specifically, to be included in the shaded area, a location needed to be at least five times more likely than the average likelihood (for all locations) to be in the path of back trajectories for the 10 percent highest days associated with a particular source profile.

Figure IV-9: Areas of highest probability of association with 8 of 11 source profiles contributing to fine particle mass at Brigantine, NJ between 1991 and 1999.
(Poirot and Wishinski, 2001)



To demonstrate this point, Figure IV-10 highlights probable source regions for summer and winter coal, which – as noted in Figure IV-8 – contributes disproportionately to light extinction on the 20 percent most impaired days. The shaded areas in this map are based on calculations of the average probability of a location being associated with summer or winter coal sources as measured at Brigantine. Specifically, they indicate locations for which the probability of association[55] is at least 1, 2, 3, 4, and 5 times greater than the average[56] probability of being associated with the coal source profiles observed at the Brigantine receptor. It is instructive to note that the location of highest probability is a region with many of the largest SO_2 sources. The locations of major SO_2 point sources have been plotted on top of the probability curves to demonstrate the high spatial correlation between the largest SO_2 emitters (denoted by the size of each circle) and the region with the highest probability of being associated with the source profile observed at Brigantine. It is also worth noting that a significant number of the highest SO_2 emitters located within the region associated with the coal source profiles are BART-eligible based on criteria discussed in detail in Chapter V and Appendix A. This suggests that application of BART on these sources is likely to have a substantial impact on the coal source profile which accounts for over half of measured mass and more than two-thirds of visibility impairment observed at Brigantine on the 20 percent haziest days.

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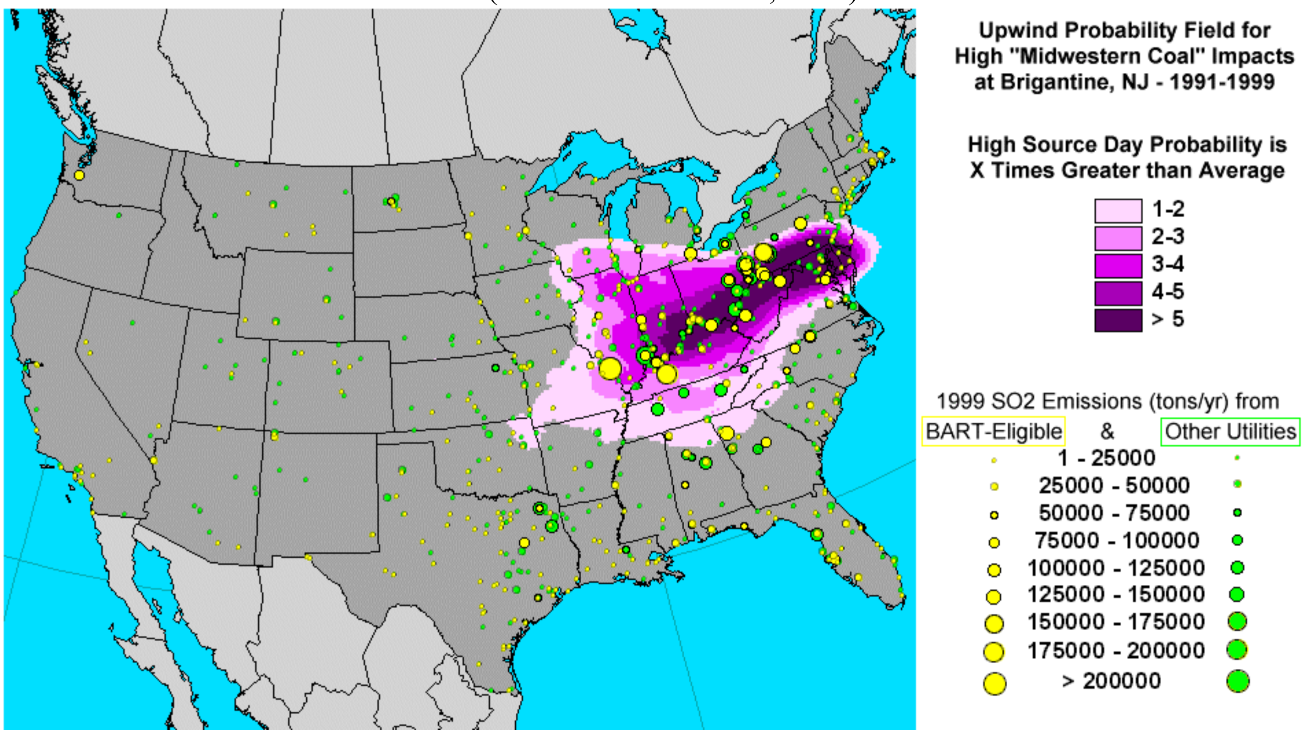
[55] Each location's source contribution is calculated by summing the total number of hours spent over a location on the 10 percent of days with the highest contribution from each source profile and expressing it as the fraction of time spent over *any* location on the 10 percent highest days.
[56] The average source contribution is calculated by taking the simple average of the source contributions from each location in the domain.

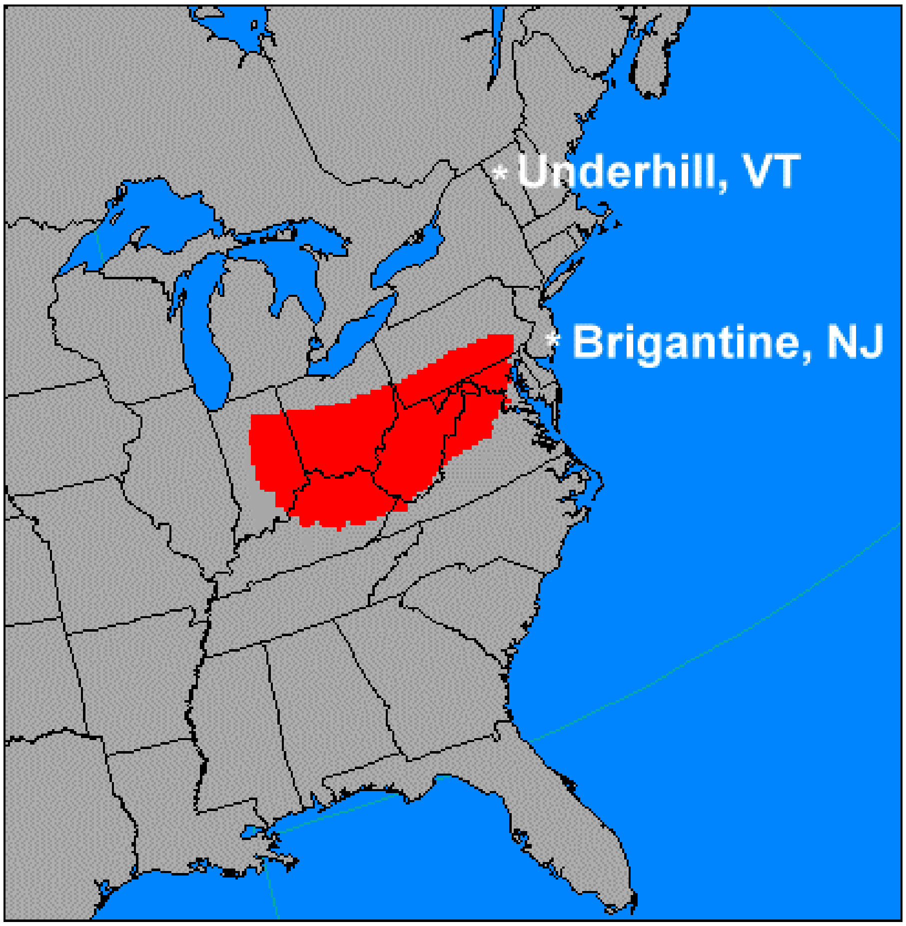
Figure IV-10: Trajectory-based assessments of upwind areas associated with high concentrations of “summer coal” and “winter coal” source impacts at Brigantine, NJ between 1991 and 1999.
(Poirot and Wishinski, 2001)



Applying a similar analysis to the Underhill site in Vermont (Poirot, et al., 2000) suggests that the source region most likely to be associated with a high downwind coal contribution is much the same for both the southern and northern portions of the MANE-VU RPO region. This earlier work and the current Brigantine analysis have been combined to identify the region having more than twice the average probability of being associated with the highest contributing days of summer and winter coal source profiles at both sites. This region has been shaded on the map shown in Figure IV-11. As this figure demonstrates, visibility at receptors located at northern and southern extremes of the MANE-VU RPO region are predominantly effected by coal burning sources in the industrial Midwest.

Results from the source apportionment analyses discussed above are consistent with the findings from other analyses described in this chapter. In particular, they suggest that the area with the highest probability of contributing to the dominant source of fine particle pollution on the worst visibility days across the MANE-VU RPO region is centered over the same region associated with low visibility days at Brigantine and other sites by the back trajectory analyses shown in Figures IV-4 to IV-6. Given the dominant role of sulfate in causing poor visibility conditions in the region and given that coal combustion is the primary source of sulfate pollution in the eastern U.S., this result is not surprising. Nevertheless, the congruence of results from these two independent analyses (which used different trajectory models[57]) lends confidence to the identification of a broad source region for the visibility impairing pollutants found at Northeast and Mid-Atlantic Class I sites.

Figure IV-11: Upwind areas with the greatest probability of being associated with high "summer coal" and "winter coal" source impacts at Brigantine, NJ (1991-99) and Underhill, VT (1989-91). (Poirot, 2001)



[57] The source apportionment analyses described in this section use the Atmospheric Transport and Dispersion Model (ATAD) whereas the trajectory analyses described in the previous section used the HYSPLIT model (See footnote 42).

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V. SO_2 and NO_X Reductions Achievable through BART Implementation

This chapter reviews major sources of visibility impairing pollutants in the eastern U.S. and provides preliminary estimates of the magnitude of emissions reductions that could be achieved by implementing the BART provisions of the regional haze rule. While other haze-forming pollutants will likely be subject to BART control requirements the focus of this preliminary analysis is on SO_2 and NO_X. Both are emitted in large quantities by the types of major stationary sources eligible for BART; hence, the largest and most significant emissions reductions likely to be achieved by the BART program will involve these two pollutants. Further analysis of opportunities to reduce other haze constituents – including organic and elemental carbon, as well as crustal material – either through BART or other regulatory mechanisms will be necessary in the coming years.

As discussed in the Introduction and in Chapter III of this report, future efforts to address visibility impairment will be more regional in scope under the 1999 regulations issued by USEPA. As a result, BART requirements are likely to be implemented more broadly and to involve a much larger number of sources than in the past, when control requirements were largely limited to individual facilities that could be linked to plume blight in Class I areas. In addition to broader geographic applicability, states will have greater flexibility in applying BART requirements. Specifically, they can substitute emissions trading programs or other regulatory approaches as long as these provide greater benefits than a source-by-source application of BART. Integrating BART control programs with existing national and regional "cap-and-trade"[58] control programs for SO_2 and NO_X is likely to be a cost-effective option for achieving further emissions reductions and making reasonable progress toward national visibility goals. The larger issue of integrating BART with other regulatory programs is discussed in Chapter VI; meanwhile this chapter provides context for that discussion by estimating what could be achieved under a straightforward, source-by-source application of BART requirements.

A. Sulfur Dioxide (SO_2)

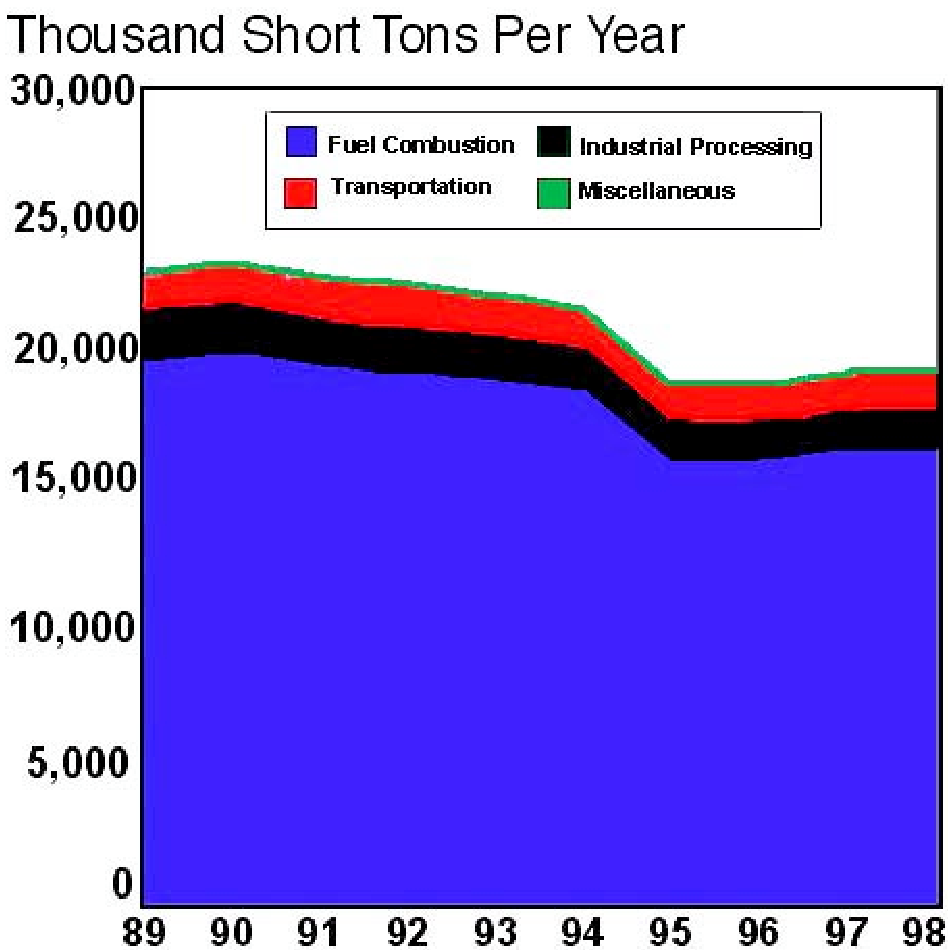
Given the dominant role of sulfate in fine particle formation and visibility impairment throughout the eastern U.S., SO_2 emissions are an obvious target of opportunity for achieving near-term haze reductions at Northeast and Mid-Atlantic Class I areas. Coal-fired power plants – which accounted for two-thirds of national SO_2

[58] Cap and trade generally refers to a regulatory approach in which a "cap" or budget for emissions is established for a defined geographical area (usually state, regional, or national); individual sources within that area receive an initial allocation of emission allowances from the budget; and allowances can subsequently be traded among individual sources. Because this approach provides individual sources with greater compliance flexibility, it is widely regarded as providing more cost-effective emissions reductions, especially on a regional or national basis.

emissions in 1998[59] – are among the 26 specific source categories to which BART requirements may be applied.

Figure V-1 shows the trend in national SO_2 emissions over the ten-year period between 1989 and 1998 (USEPA, 2000a). It indicates a decline in total emissions of about 20 percent over this period, with a significant step-wise drop coinciding with the implementation of Phase I of the federal Acid Rain Program in 1994-95. After 1995, emissions actually began to increase slightly, a trend that probably reflects increased electricity demand in the late 1990s combined with the availability of excess emissions allowances that were banked as a result of substantial initial over-compliance with Phase I requirements in the mid-90s.[60] In 2000, a second phase of the Acid Rain Program went into effect, which should eventually reduce national power sector SO_2 emissions to just under 9 million tons annually. This represents a roughly 4 million ton (32 percent) further reduction from the 13 million ton power plant total reached in 1998.

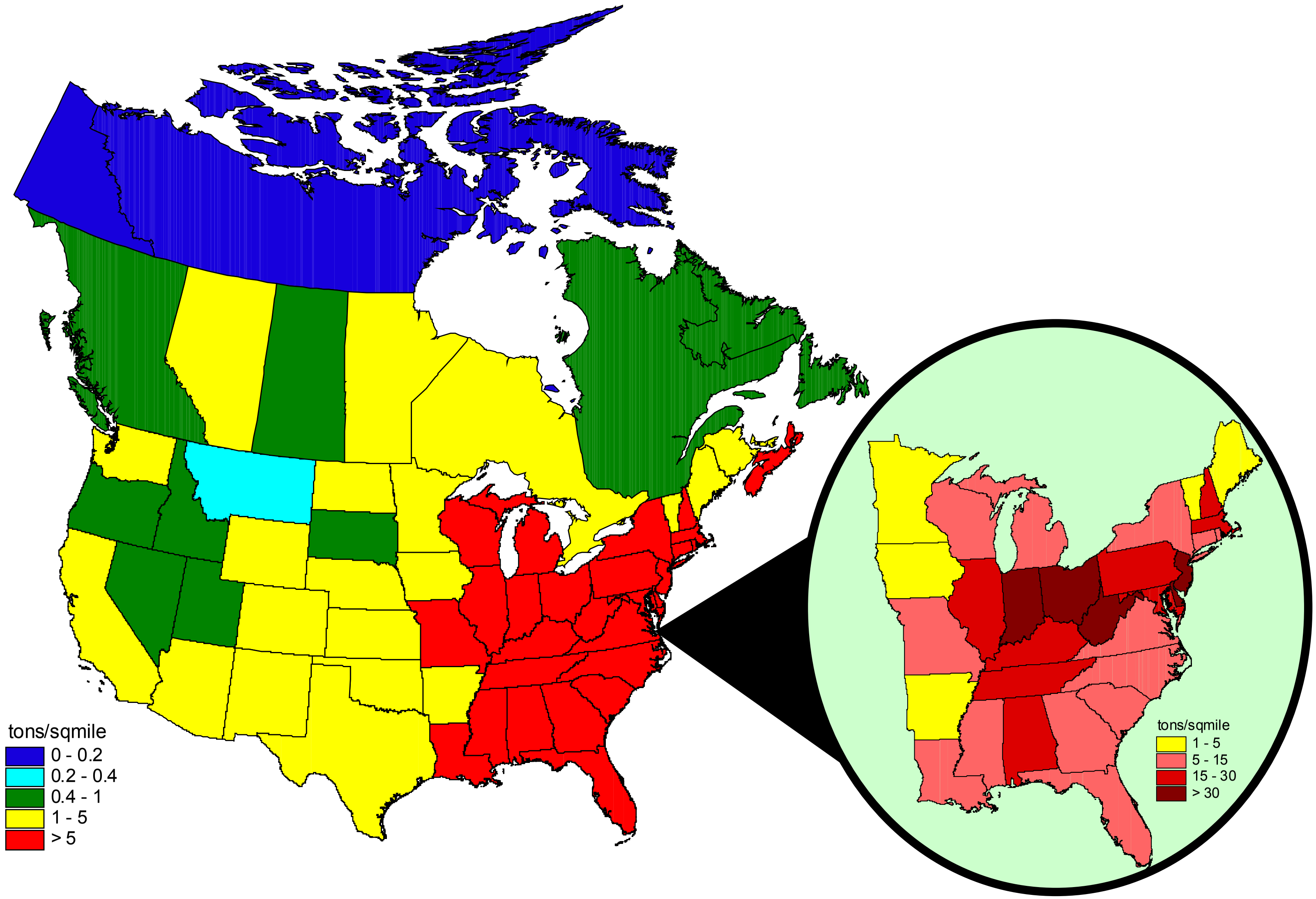
Figure V-1: Ten-year national SO_2 emissions trend from 1989 to 1998. (USEPA, 2000a)



[59] Source: USEPA, 2000a. In fact, coal-fired power plants remain the single largest source of SO_2 emissions in the U.S.
[60] See further discussion in Chapter VI.

Figure V-2 shows SO_2 emissions *density* (in tons per square mile) aggregated by state in the U.S. (USEPA, 2001a) and by province in Canada (Environment Canada, 2001). The comparison indicates that emissions when divided by area exhibit less between-state (or between-province) variation than do absolute emissions. Emissions density, however, is not necessarily the optimal metric for assessing relative source contributions to a downwind area. Accurate determination of source contributions will depend on meteorology, the quantity of emissions released at a given point or in a given area, and distance to the receptor site. Alternative measures of emissions distributions (for example, on a per capita basis) may be equally or more informative than the density metric shown in Figure V-2.

Figure V-2: SO_2 emissions density map for United States and Canada.



Note: based on 1996 emissions data for U.S. (USEPA,2001b) and 1995 emissions data for Canada (Environment Canada, 2001).

Table V-1 provides a breakdown of SO_2 emissions by source category for the 29-state geographic source region tentatively identified using various statistical and modeling techniques in the previous chapter (see Figure IV-7).[61] The emissions shown are for 1996, the last year for which detailed state-by-state inventory data are available. The table indicates that the 26 source categories considered potentially eligible for BART account for a large fraction (over 85 percent) of total SO_2 emissions in the identified source region.

Figure V-3 provides more detail on the SO_2 contribution of potentially BART-eligible sources generally, and BART-eligible power plants specifically. The left-most column within each state indicates aggregate SO_2 emissions from the 26 source types potentially eligible for BART requirements. The second column shows emissions from fossil fuel fired steam electric plants of more than 250 million Btu/hr heat input (category 1 in the list of potentially BART-eligible source types shown in Chapter III). Finally, the third bar shows SO_2 emissions from those steam-electric plants that satisfy other BART-eligibility criteria (i.e., have the potential to emit more than 250 tons/yr and began operation between 1962 and 1977).[62] Clearly, large steam electric boilers account for a substantial portion of the total SO_2 emissions associated with major point sources and BART-eligible boilers, in turn, make a significant contribution to the power plant total in many states.[63]

Table V-1: Inventory of 1996 SO_2 emissions for 29 eastern states plus the District of Columbia, listed by source category.

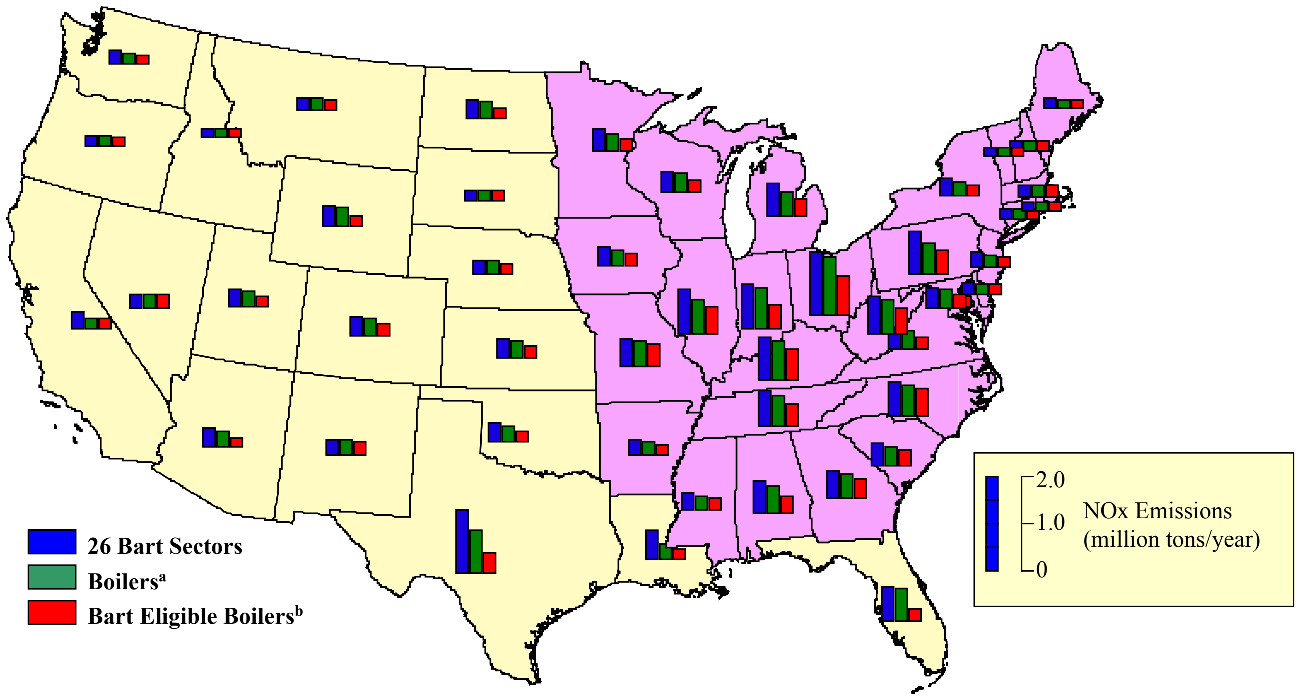
Source Category	SO_2 Emissions (Tons/year)	Contribution to Total Inventory (%)
Mobile Sources	**191,597**	**1.3**
Area Sources	**1,633,797**	**11.1**
Point Sources	**12,855,196**	**87.6**
Point Sources within the 26 BART emission categories	**12,501,855**	**85.2**

Notes: Emissions data from 1996 National Emissions Trends (NET) Inventory (USEPA, 2001a).

[61] It should be emphasized that the source region identified in Figure IV-7 is preliminary. Further analysis and modeling may result in modifications, and may indicate that additional states should be included in the source region for visibility impairing pollutants affecting Northeast and Mid-Atlantic Class I areas.

[62] To determine eligibility, the list of boilers in the 1996 NET inventory were cross-referenced against data from USEPA's Clean Air Markets Division. See Chapter III for a detailed explanation of BART-eligibility criteria. Recently drafted, but not yet formally proposed BART guidance suggests that emission units within the same industrial grouping (that is those units with the same 2-digit Standard Industrial Classification (SIC) code) be summed and considered a single source (USEPA, 2001b).

Figure V-3: 1996 SO_2 point source emissions by category for a preliminary 29-state source region.



Notes:
a) Boilers with a design capacity to emit at least 250 mmBtu/hr
b) See BART-eligibility requirements in Chapter III

To estimate the emissions reductions that could be achieved through a source-by-source application of BART requirements, NESCAUM examined the emissions and BART-eligibility of individual power plants throughout the preliminary 29-state source region identified in Chapter IV. The analysis identified 387 units (out of a total of 2470 units subject to Title IV) within this region that met all applicable BART-eligibility criteria with respect to start-up date and potential to emit.[64] Appendix A contains a more detailed description of the analysis including assumptions used to estimate potential emissions reductions and underlying data sources.[65] The results indicate that over 5.6 million tons of SO_2 were emitted in 1999 from BART-eligible steam electric boilers in the preliminary source region. Note that the analysis did not include other point sources potentially subject to BART, though some of these sources undoubtedly contribute to overall emissions. Facility-level data are generally more difficult to obtain for other source categories; in addition, their contribution to SO_2 emissions, relative to that of

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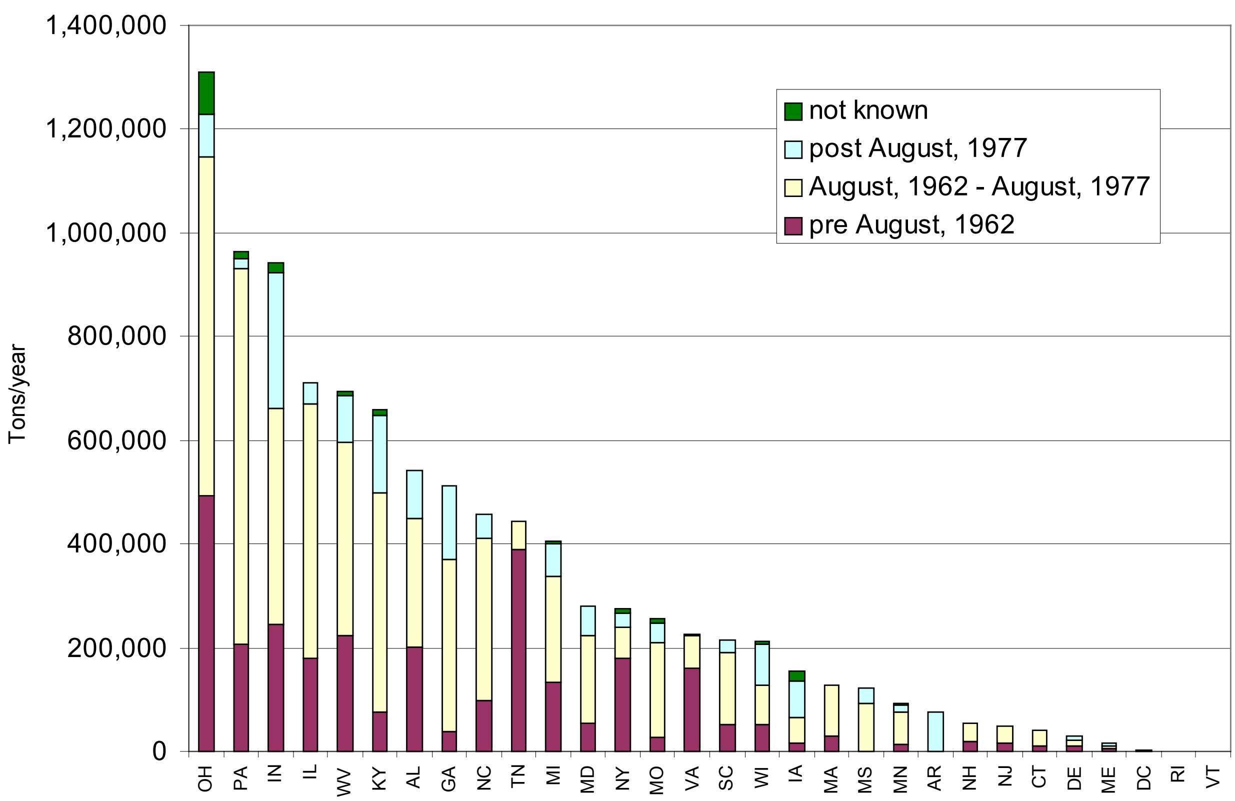
[63] Coal accounts for 94 percent and oil for only 4 percent of the total 1999 SO_2 emissions associated with 387 potentially BART-eligible power plants identified later in this section.
[64] See footnotes 61 and 62.
[65] The USEPA Clean-Air Market Division 1999 Emission Scorecard is a database outlining the acidic precursor emissions of power plants in the Acid Rain Program (USEPA, 2001c). The database is available online at: http://www.epa.gov/airmarkets/emissions/score99/index.html. This database provides each Title IV affected unit's SO_2 and NO_X emissions (tons/year), heat input (mmBtu), primary fuel and boiler type, and lists any current control technology in use by each unit.

steam-electric boilers, is generally much smaller. Nevertheless, BART applicability to other source types remains an outstanding consideration for future planning efforts.

Figure V-4 compares 1999 SO_2 emissions from steam-electric boilers that meet BART-eligibility criteria to emissions from other large (i.e. greater than 250 million Btu/hr heat input) boilers that began operation outside the window for BART-eligibility (i.e. before August 1962 and after August 1977). The figure indicates that while the BART program captures a large fraction of the power plant inventory, facilities that began operating prior to 1962 still make a substantial contribution to total SO_2 emissions. Emissions from these and other non-BART-eligible sources will eventually need to be addressed to achieve the long-term goal of restoring pristine visibility conditions at all Class I areas.

Meanwhile, BART-eligible units are responsible for a disproportionate share of emissions in a number of states — most notably in Pennsylvania, Illinois, North Carolina, South Carolina, Massachusetts, New Hampshire, New Jersey and Connecticut, but also in Ohio, West Virginia, Kentucky, Georgia, Michigan and Maryland. BART-eligible units are responsible for a smaller share of power plant emissions in Tennessee, New York, Iowa and Virginia.

Figure V-4: 1999 SO_2 emissions by date of power plant operation.



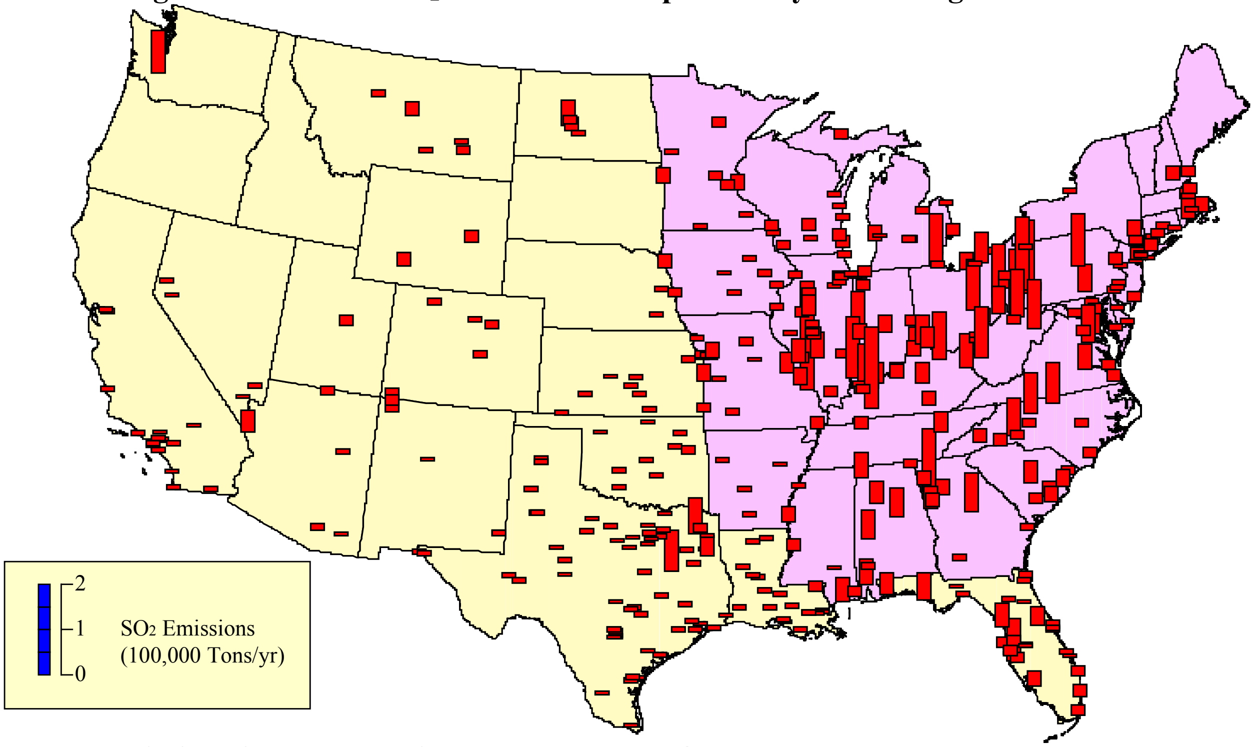
The primary add-on control technology for reducing SO_2 emissions from power plants is flue gas desulfurization (FGD) or, more colloquially, "scrubber" technology. FGD is a well-established control technology that routinely achieves control efficiencies of over 95 percent in modern applications. In the proposed BART rule issued by USEPA, a proposed presumption of control effectiveness is set at 90 to 95 percent for previously uncontrolled utility boilers.

Due to the availability of compliance options such as fuel switching to low-sulfur coal, FGD has been installed at only a relatively small number of power plants, despite the existence of the federal Acid Rain Program.[66] Thus, the emissions reductions that could be achieved by applying modern scrubber technology to BART-eligible boilers throughout the preliminary 29-state source region are substantial. Figure V-5a maps the geographic distribution of potentially BART-eligible power plant SO_2 emissions, while Figure V-5b shows how the application of FGD (at a presumptive control effectiveness of 95 percent) would drastically reduce SO_2 emissions from these sources. Resulting emissions reductions are aggregated by state in Figure V-6 and summarized in Table V-2.

The potential emissions reductions estimated here (roughly 5 million tons) may tend to overstate actual emissions reductions that would be achieved through source-by-source application of BART if units which have already obtained some level of control through the use of low-sulfur coal switch to higher sulfur coal after FGD installation. This detail was not accounted for in the present analysis due to the unavailability of an accurate list of sources which have opted for fuel switching to achieve compliance under Phase I of the Title IV program. However, any overestimate of potential emissions reductions in the present analysis is not likely to be significant for two important reasons. First the emissions reductions achieved by low-sulfur coal substitution are not nearly as significant as the control efficiency that can be obtained through the application of "scrubber" technology (typically 40-50 percent versus 90-95 percent for scrubbers). Second, the cost of western, low-sulfur coal currently remains quite competitive with higher sulfur coals and many sources might choose to continue using low-sulfur coal to generate extra allowances.

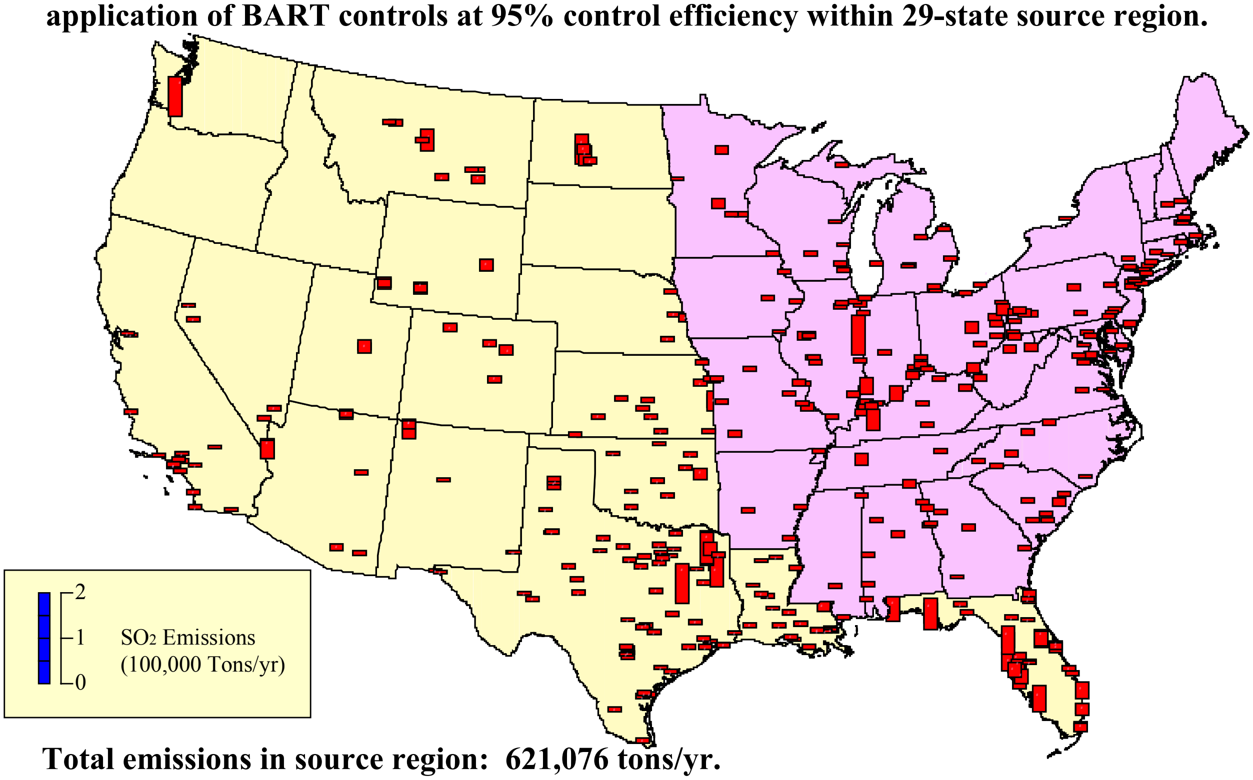
[66] There are a number of explanations for this outcome, chief among them that a large number of units found it more cost-effective to comply with Phase I requirements by switching to lower-sulfur coal (see further discussion in the previous NESCAUM haze report).

Figure V-5a: 1999 SO_2 emissions from potentially BART-eligible sources.



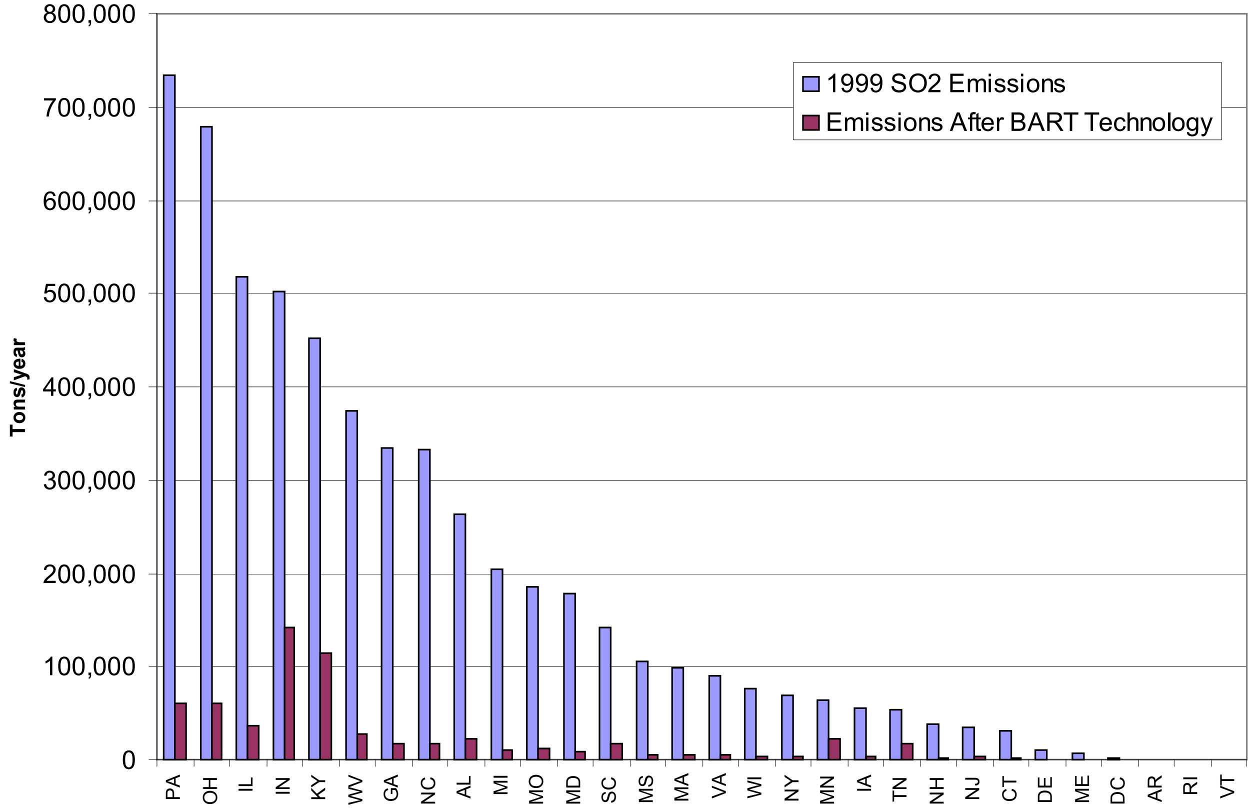
Total emissions in source region: 5,630,789 tons/yr.

Figure V-5b: Estimated SO_2 emissions from potentially BART-eligible sources after application of BART controls at 95% control efficiency within 29-state source region.



Total emissions in source region: 621,076 tons/yr.

Figure V-6: Potential BART-eligible SO_2 emissions reductions[a] aggregated by state.



Note:
a.) Based on 1999 emissions from BART-eligible fossil-fuel fired steam electric plants.

Table V-2: Estimated state-level SO_2 emissions reductions from BART-eligible boilers, based on 1999 emissions.

State	1999 SO_2 emissions from BART-Eligible Boilers (tons/year)	Est. SO_2 Emissions Reduction (tons/year)	State Avg. % SO_2 reduction	Est. SO_2 Emissions After BART (tons/year)
Alabama	263,758	241,137	91	22,620
Arkansas	661	628	95	33
Connecticut	30,787	29,247	95	1,539
Delaware	10,491	9,966	95	525
District of Columbia	1,432	1,361	90	72
Georgia	333,433	316,761	95	16,672
Illinois	516,929	479,929	93	36,999
Indiana	501,333	358,655	72	142,678
Iowa	55,095	52,341	92	2,755
Kentucky	452,426	337,526	75	114,900
Maine	6,406	6,086	95	320
Maryland	177,682	168,798	95	8,884
Massachusetts	97,867	92,973	95	4,893
Michigan	204,784	194,545	95	10,239
Minnesota	64,007	41,185	64	22,822
Mississippi	104,978	99,729	95	5,249
Missouri	185,914	173,296	93	12,618
New Hampshire	37,834	35,943	95	1,892
New Jersey	33,798	31,189	92	2,609
New York	69,416	65,946	95	3,471
North Carolina	333,169	316,510	95	16,658
Ohio	679,582	619,383	91	60,199
Pennsylvania	734,015	672,963	92	61,051
South Carolina	141,169	124,371	88	16,798
Tennessee	54,099	36,270	67	17,830
Virginia	89,713	85,227	95	4,486
West Virginia	374,301	345,823	92	28,478
Wisconsin	75,711	71,925	95	3,786
Total	**5,630,789**	**5,009,713**	**N/A**	**621,076**

Notes: Based on 1999 emissions assuming all uncontrolled Title IV BART-eligible units are currently operating at 0 percent control efficiency. Emissions from units that are already equipped with FGD were assumed to remain constant, while all other units were assumed to achieve 95 percent control efficiency after BART implementation. Capacity utilization at all units was assumed to remain constant for the purposes of this calculation. Vermont and Rhode Island have no BART-eligible power plant emissions.

Interestingly, the roughly 5 million ton reduction potential shown in Table V-2 is somwhat greater than the total additional power plant SO_2 reductions that will ultimately be required under Phase 2 of the national Acid Rain Program.[67] In other words, if all potentially BART-eligible power plants in the 29-state source region are retrofitted with scrubbers and begin achieving 95 percent SO_2 reductions, it is possible that no further reductions at other plants would be necessary to achieve Title IV emissions caps. However, this outcome would still leave close to 9 million tons of annual power plant emissions, in addition to the approximately 3 million tons of SO_2 emitted by other sources. At these emissions levels, visibility conditions at Northeast and Mid-Atlantic Class I areas – while probably improved over current levels – would continue to fall well short of pristine.

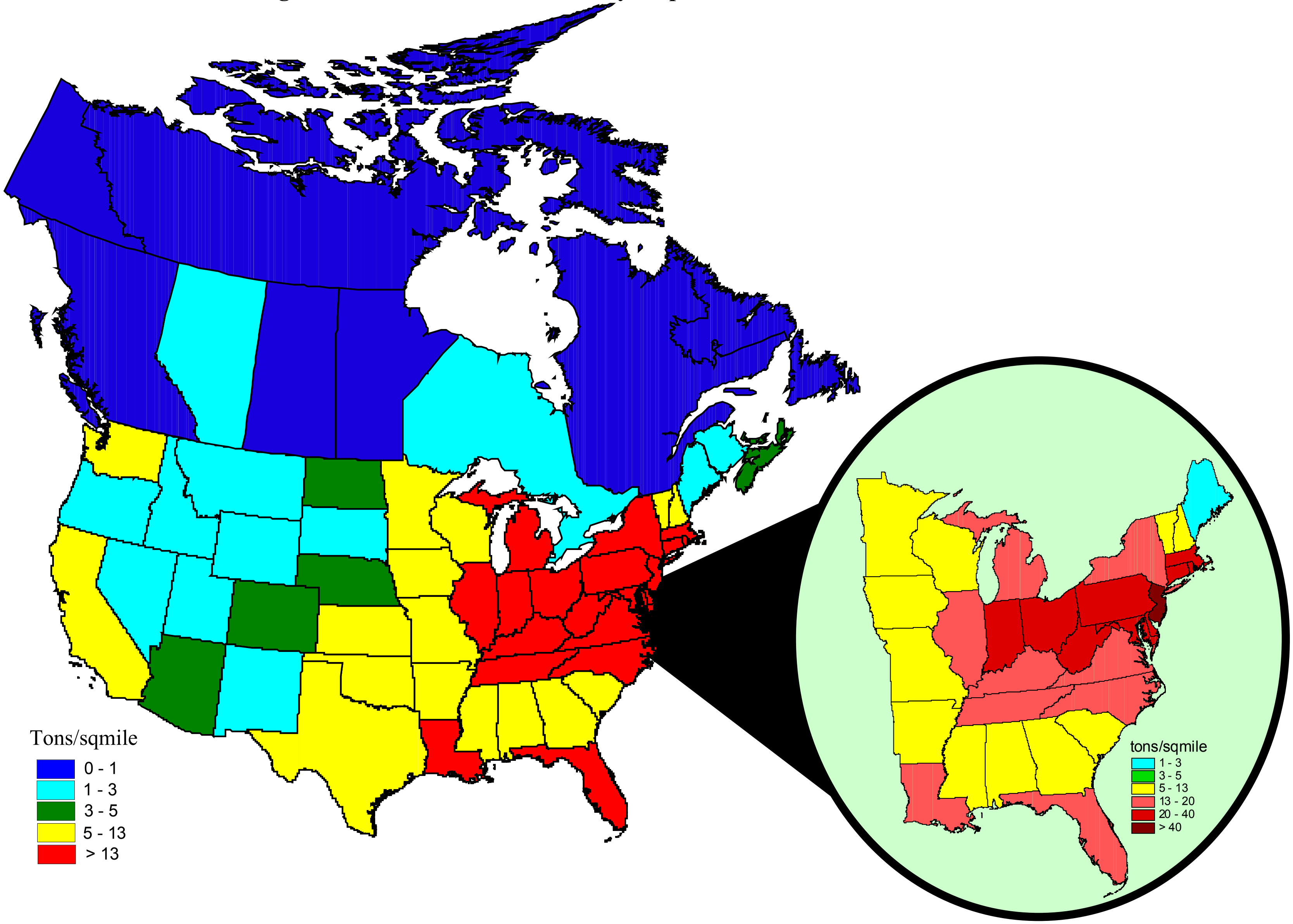
B. Oxides of Nitrogen (NO_X)

Nitrate generally accounts for a substantially smaller fraction of fine particle mass and related light extinction than sulfate and organic carbon at eastern Class I sites. Nevertheless, NO_X emissions contribute directly to visibility impairment in the eastern U.S. by forming light-scattering nitrate particles. Notably, nitrate may play a more important role at urban sites and in the wintertime. In addition, NO_X has an indirect effect on summertime visibility by virtue of its role in ozone formation, which in turn promotes the formation of secondary organic aerosols.

Figure V-7 shows NO_X emissions density aggregated by state in the U.S. (USEPA, 2001b) and by province in Canada (Environment Canada, 2001). However, as with the earlier density map shown for SO_2, a number of caveats apply as to the usefulness of the density metric for future haze planning efforts.

[67] At roughly 13 million tons of power plant SO_2 emissions nationwide in 1998, a reduction of just over 4 million tons would be necessary to reach the 8.9 million ton cap that will eventually apply under Phase II of the Acid Rain Program, once bonus and carry-over allowances from Phase I (which currently total roughly 10 million tons) are depleted.

Figure V-7: NO_X emissions density map for United States and Canada.



Note: based on 1996 emissions data for U.S. (USEPA,2001b) and 1995 emissions data for Canada (Environment Canada, 2001).

Table V-3 shows the contribution to overall NO_x emissions in the 29-state preliminary source region by source category. Because non-point sources, such as automobiles and trucks, account for a substantial share of overall NO_x emissions – particularly in the more urbanized mid-Atlantic and northeastern states – the fraction of total emissions potentially subject to BART restrictions is lower than in the case of SO_2. Nevertheless, power plants remain a major source of NO_x emissions – especially in parts of the industrial Midwest – and, at over 6 million tons of NO_x emissions annually, account for more than one quarter of the national inventory for this haze-forming pollutant. Since 1980,[68] nationwide emissions of NO_X from all sources have shown little change. In fact, emissions increased by 2 percent between 1989 and 1998 (EPA, 2000a). This increase is most likely due to industrial sources and the transportation sector, as power plant combustion sources have shown modest emissions reductions during this same time period.

Table V-3: Inventory of NO_X emissions in 1996 for 29 eastern states plus the District of Columbia, listed by source category.

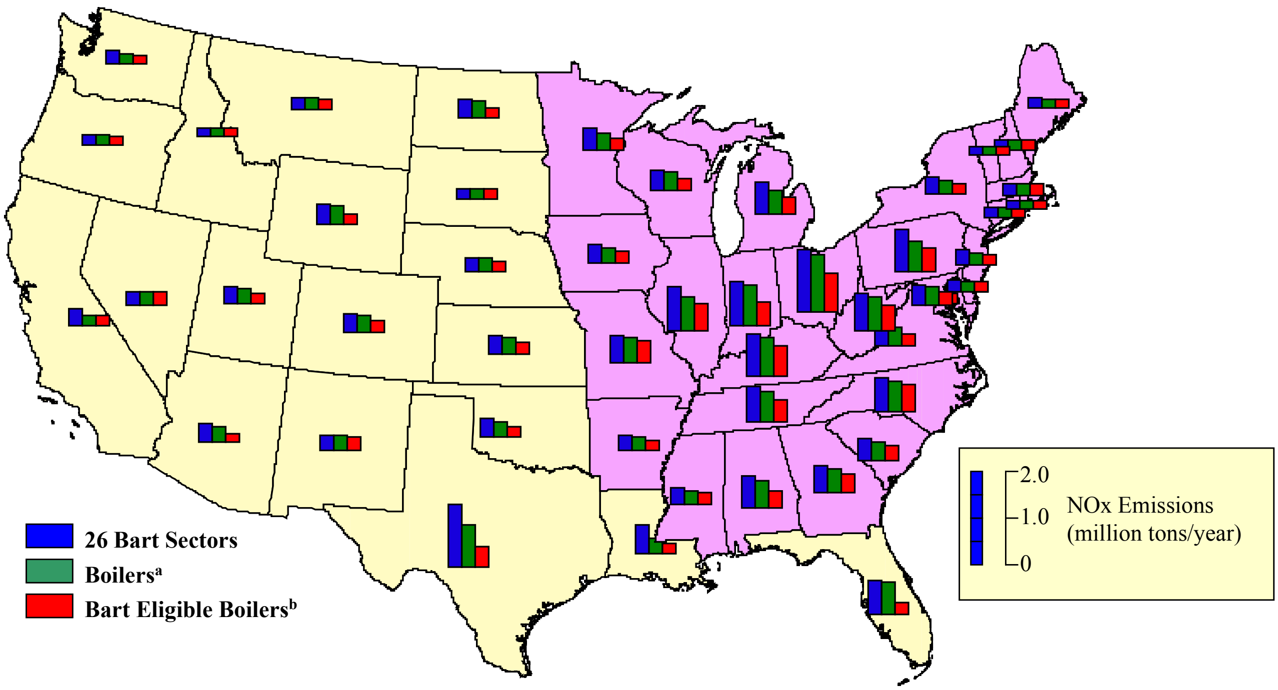
Source Category	NO_X Emissions (tons/year)	Contribution to Total Inventory (%)
Mobile Sources	**4,911,310**	**32.7**
Area Sources	**4,121983**	**27.4**
Point Sources	**6,004,124**	**39.9**
Point Sources within the 26 BART emission categories	**5,309351**	**35.3**

Notes: Emissions data from 1996 NET Inventory, USEPA, 2001a.

To estimate potential NO_x reductions achievable through BART implementation in the preliminary 29-state source region for Northeast and Mid-Atlantic visibility impairment, NESCAUM conducted an analysis similar to that described in the previous section for SO_2.[69] First, all power plants that met the BART-eligibility criteria for NO_x were identified and their emissions were compared against: (1) total emissions for all potentially BART-eligible point sources and (2) all major (i.e. greater than 250 million Btu/hr heat input) steam-electric boilers, regardless of age. The results are shown in Figure V-8. As with SO_2, fossil-fuel fired steam-electric power plants account for a large share of total point source NO_x emissions and BART-eligible boilers account, in many states, for a significant fraction of total power sector emissions. Overall, BART-eligible steam-electric boilers in the 29-state source region emitted over 2.1 million tons of NO_X in 1999. Note that, as with SO_2, the analysis did not include other major point sources

[68] 1980 is the base year for all control programs under the CAA's Title IV requirements.
[69] Details of this analysis are contained in Appendix B.

Figure V-8: 1996 NO_X point source emissions by category.



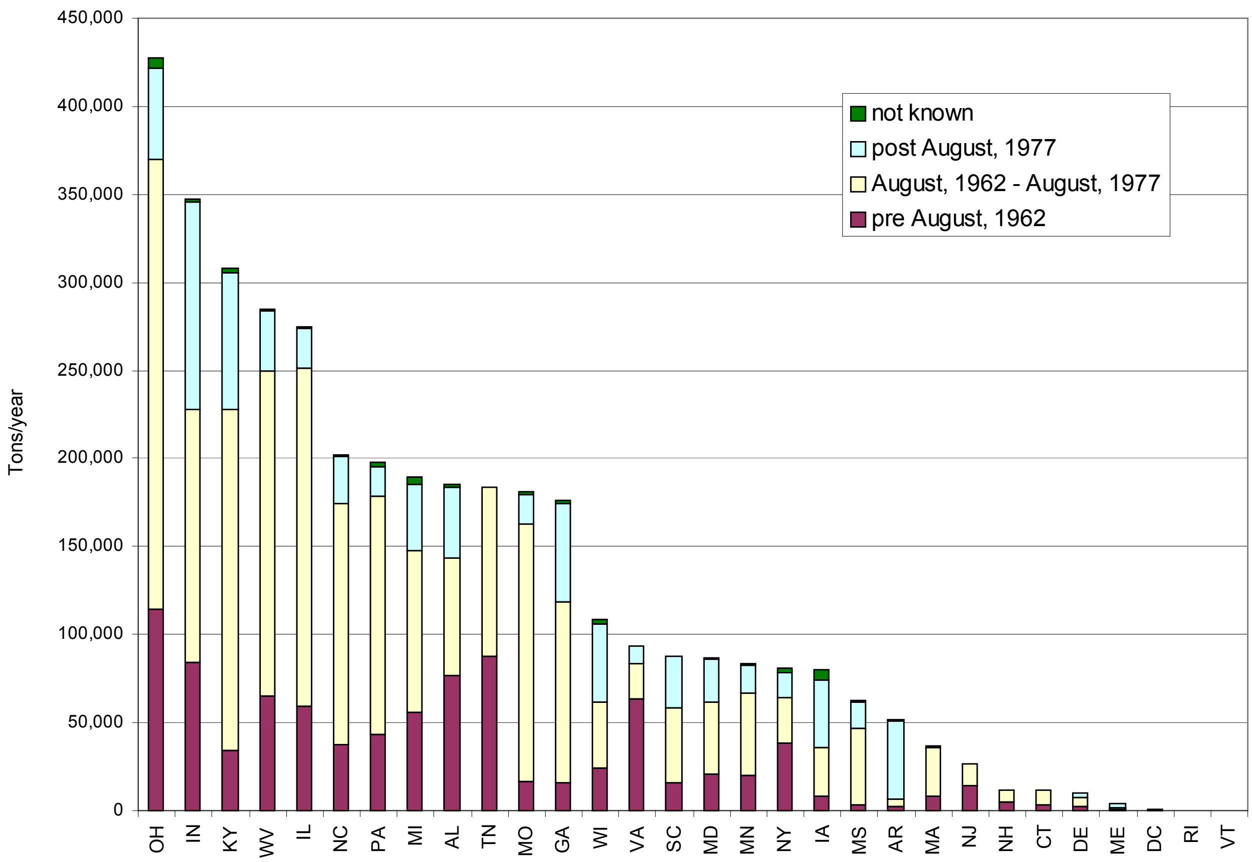
Notes:
a) Boilers with a design capacity to emit at least 250 mmBtu/hr
b) See BART-eligibility requirements in Chapter III

potentially subject to BART, though some of these sources are undoubtedly associated with non-trivial NO_x emissions.

Figure V-9 compares 1999 NO_x emissions from steam-electric boilers that meet BART-eligibility criteria to emissions from other large (i.e. greater than 250 million Btu/hr heat input) boilers that began operation outside the window for BART-eligibility (i.e. before August 1962 and after August 1977). The figure indicates that while the BART program captures a somewhat larger fraction of the power plant NO_x inventory (relative to the comparable figure for SO_2 (Fig. V-3)), facilities that began operation outside the BART-eligibility window still make a substantial contribution to total NO_x emissions.

A number of control options exist for reducing NO_x emissions from steam-electric boilers. These include combustion modifications (such as low-NO_x burners) as well as advanced, post-combustion add-on controls, such as selective catalytic reduction (SCR). SCR can reduce NO_X emissions at power plants by over 90 percent, especially when combined with other measures such as combustion modifications. In contrast to SO_2, recently published USEPA guidance does not specify a presumptive BART control technology or control effectiveness for power plant NO_x emissions. Thus, for the purposes of this analysis, SCR in combination with other technologies was assumed to represent BART. Given that the summertime NO_x reductions called for under other existing regulatory programs[70] will require substantial numbers of SCR retrofits, this seems a reasonable assumption for purposes of estimating the possible magnitude of future BART reductions. In addition, a maximum control effectiveness of 94 percent was assumed, based on the demonstrated performance of recent SCR retrofits. Figure V-10a shows the distribution of current NO_x emissions from BART-eligible units across the identified source region. Figure V-10b shows estimated emissions once the 94 percent control effectiveness achievable through SCR is applied to each of these units. As in the previous section on SO_2, the same results are aggregated by state in Figure V-11 and summarized in Table V-4.[71]

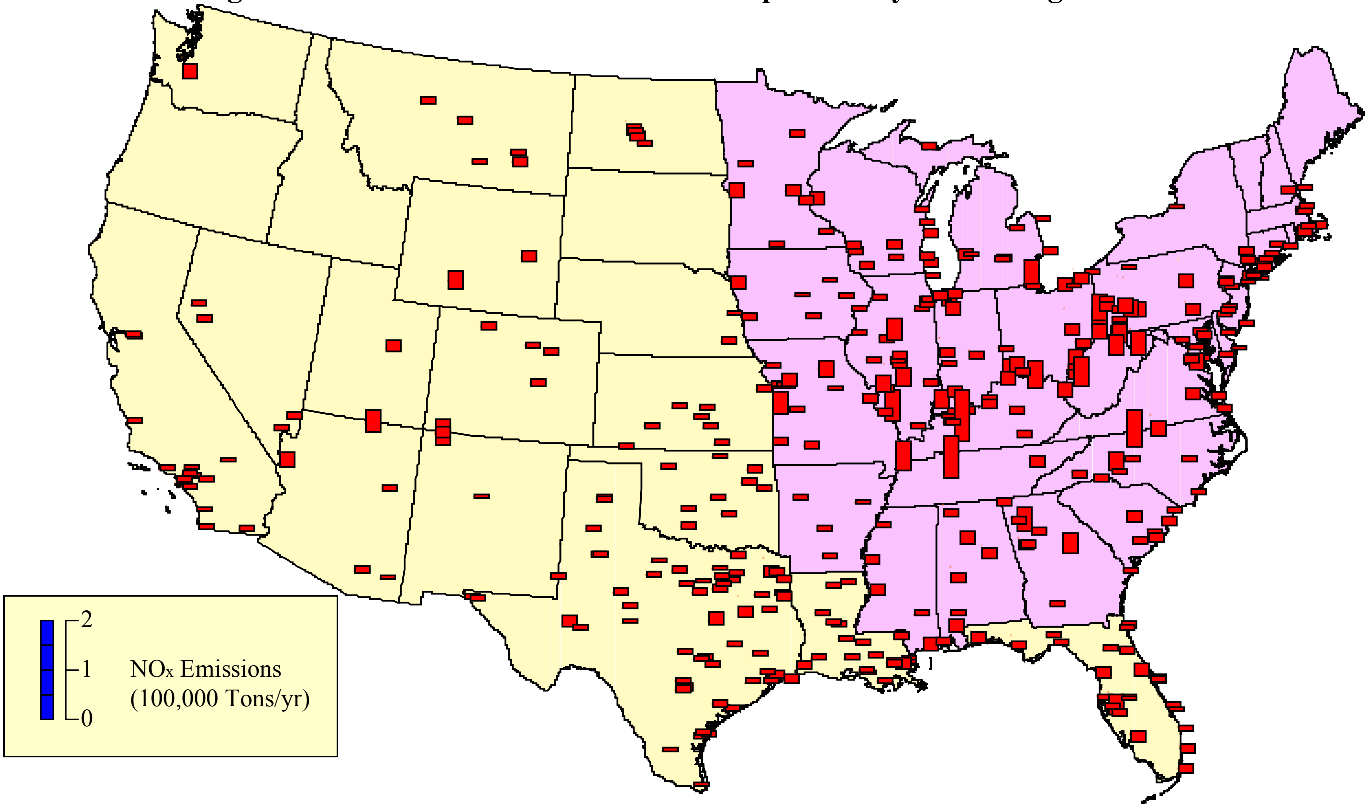
Figure V-9: NO_X emissions from power plants located in the preliminary 29-state source region by time period.



[70] Notably, USEPA's Section 110 SIP call (see further discussion in Chapter VI).

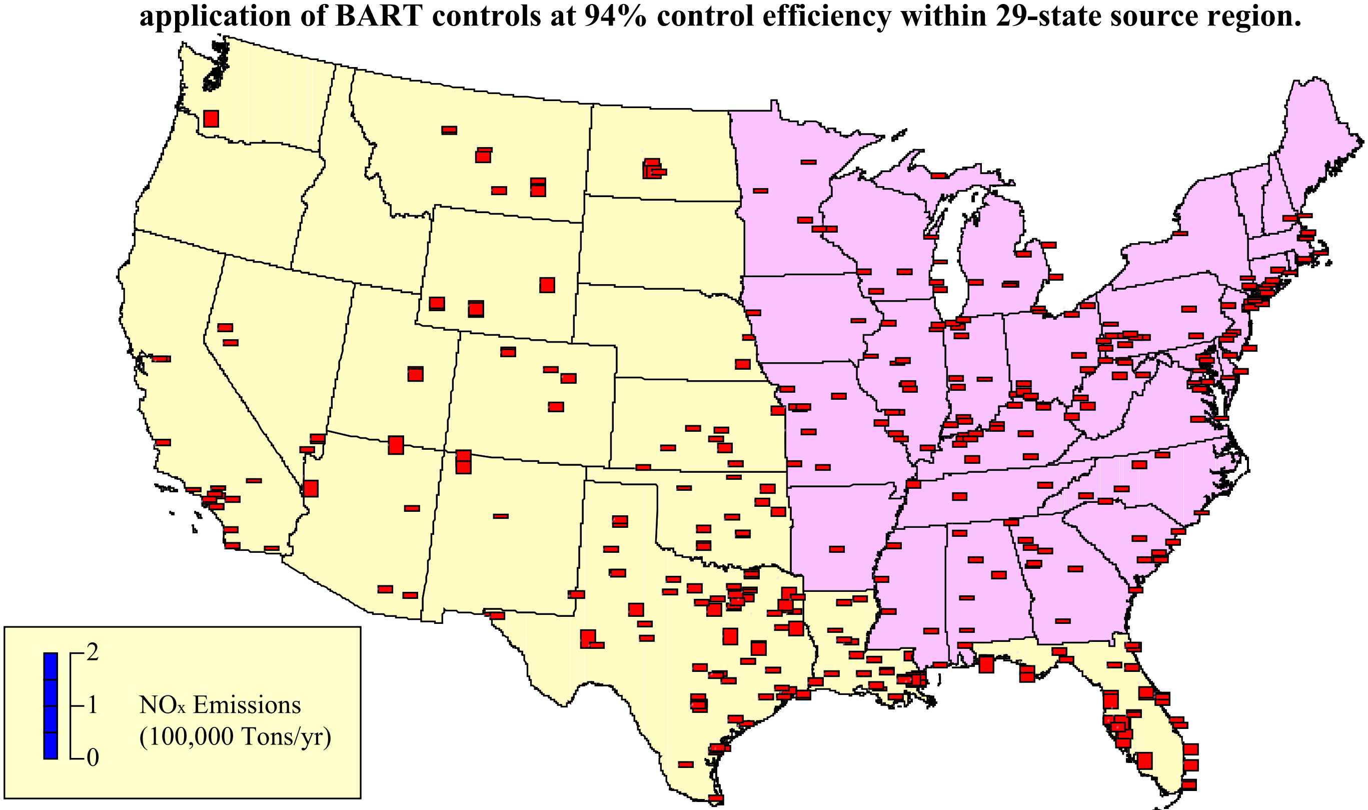
[71] For the purpose of this analysis, any source with low NO_X burner or equivalent technology was assumed to achieve a control efficiency of 35 percent. For these sources, the addition of SCR was assumed to be BART, resulting in an overall control efficiency of 94 percent. If no controls were present, the combination of low NO_X burner and SCR technology was assumed to achieve an overall control efficiency of 94 percent.

Figure V-10a: 1999 NO_X emissions from potentially BART-eligible sources.



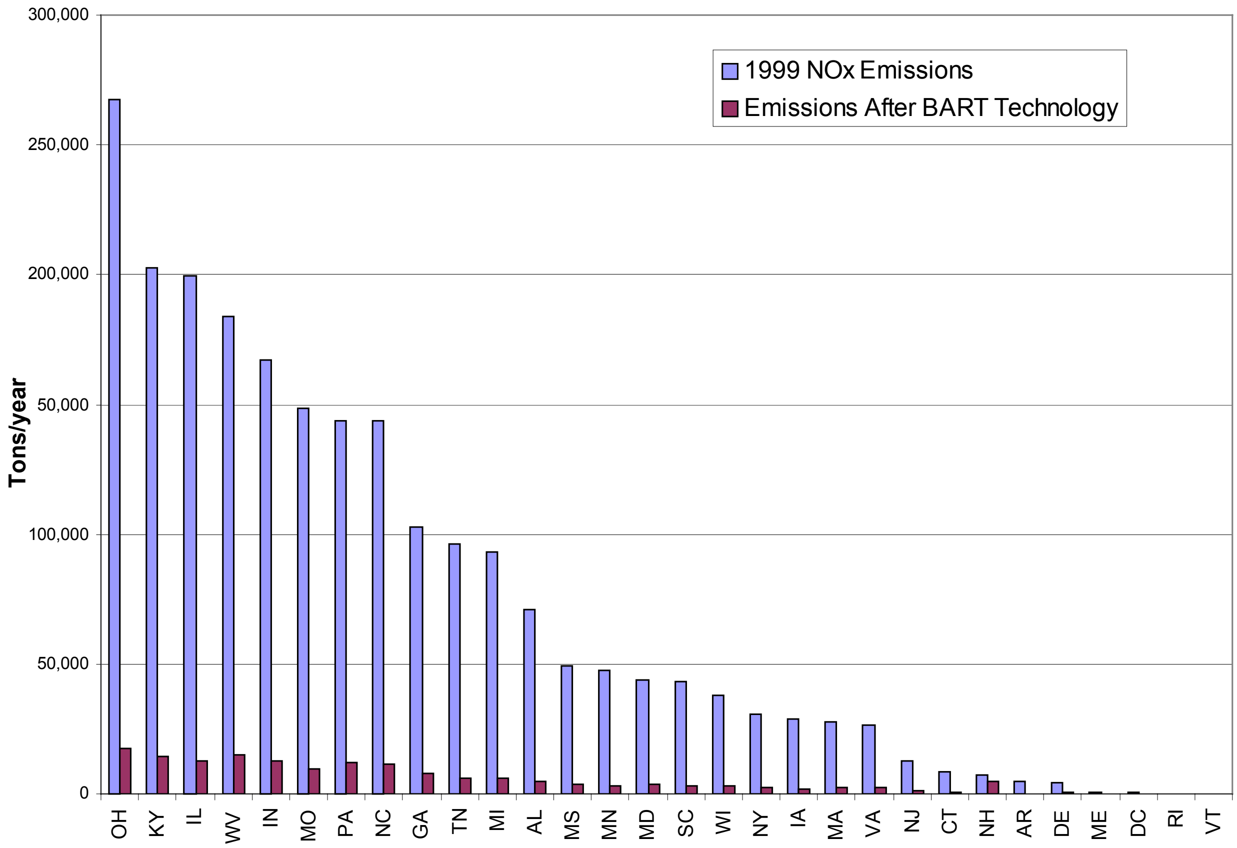
Total emissions in source region: 2,193,836 tons/yr.

Figure V-10b: Estimated NO_X emissions from potentially BART-eligible sources after application of BART controls at 94% control efficiency within 29-state source region.



Total emissions in source region: 161,568 tons/yr.

Figure V-11: Potential BART-eligible NO_X emissions reductions[a] aggregated by state.



Note:
a.) Based on 1999 emissions from BART-eligible fossil-fuel fired steam electric plants.

Table V-4: Estimated state-level NO_x emissions reductions from BART-eligible boilers, based on 1999 emissions.

State	1999 NO_x emissions from BART-Eligible Boilers (tons/year)	Est. NO_x Emissions Reduction (tons/year)	State Avg. % NO_x reduction	Est. NO_x Emissions After BART (tons/year)
Alabama	70,885	66,160	93	4,725
Arkansas	4,892	4,598	94	294
Connecticut	8,127	7,551	93	576
Delaware	4,466	4,104	92	362
District of Columbia	447	420	94	27
Georgia	102,830	94,803	92	8,027
Illinois	199,802	186,978	94	12,824
Indiana	167,306	154,871	93	12,435
Iowa	28,857	27,023	94	1,835
Kentucky	202,439	188,160	93	14,279
Maine	879	827	94	53
Maryland	44,040	40,681	92	3,358
Massachusetts	27,868	25,363	91	2,505
Michigan	93,098	87,378	94	5,720
Minnesota	47,388	44,099	93	3,289
Mississippi	49,092	45,574	93	3,518
Missouri	148,388	138,846	94	9,542
New Hampshire	7,043	2,193	31	4,850
New Jersey	12,739	11,712	92	1,027
New York	30,366	27,786	92	2,580
North Carolina	143,782	132,596	92	11,187
Ohio	267,377	250,002	94	17,375
Pennsylvania	143,802	131,710	92	12,092
South Carolina	43,293	40,181	93	3,112
Tennessee	96,199	90,427	94	5,772
Virginia	26,307	24,082	92	2,225
West Virginia	183,951	168,922	92	15,029
Wisconsin	38,174	35,221	92	2,953
Total	**2,193,836**	**2,032,268**	**N/A**	**161,568**

Notes: Based on 1999 emissions assuming all Title IV BART-eligible units considered uncontrolled are currently operating at 0 percent control efficiency. It is assumed 94 percent control efficiency can be obtained by adding new control technologies. Emissions at all units with low NOx burner, water injection, overfire air, combustion modification with fuel reburn in place are assumed to be operate at 35 percent control efficiency (with an additional 90 percent control efficiency possible), those units with SCR are assumed to operate at 94 percent control efficiency and capacity utilization is assumed to remain constant. Vermont and Rhode Island have no BART-eligible power plant emissions.

As in the case of SO_2, there is certain to be overlap between existing regulatory programs (most of which, at present, seek to reduce NO_x emissions to combat ozone smog and, to a lesser extent, acid rain) and future visibility-related efforts to reduce NO_x. The extent of likely overlap in terms of driving investment in NO_x control technologies is discussed in Chapter VI in the context of the required summertime NO_X reductions under USEPA's Section 110 NO_x SIP call. While the states included in the SIP call do not correspond exactly to those identified in the preliminary haze source region defined in this report, the overall summertime reductions estimated to be achievable through BART in this analysis, at over 800,000 tons, represent over three-quarters of the total reductions which are likely to be required under the SIP call. This finding, together with that suggested by a preliminary analysis of BART-eligible SO_2 reductions, demands that consideration be given to the integration of these regulatory efforts, a subject to which we turn in the next chapter.

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VI. The Relationship of BART to Other Control Programs

There is likely to be substantial overlap between future BART implementation efforts and other regulatory programs, especially those aimed at reducing SO_2 and NO_x emissions. Hence, the first two sections of this Chapter take up the question of how BART might interact with Title IV Acid Rain requirements (in the case of SO_2) and NO_x SIP call/Section 126 requirements (in the case of NO_x). Section C discusses the need for reductions of other haze-causing pollutants and the interaction of visibility SIPs with state plans for implementing new fine particle ($PM_{2.5}$) ambient air quality standards. Finally, Section D discusses control costs for achieving SO_2 and NO_X reductions.

A recurrent theme throughout this chapter is the importance of coordinating BART implementation, which has historically been applied on command-and-control basis, with existing programs, some of which are based on a cap-and-trade approach. If source-by-source BART requirements are simply overlaid on existing market-based programs they may either: (a) lower the de-facto cap under which all sources in a given geographic region operate or (b) achieve no meaningful reductions beyond the caps already being imposed because any excess allowances generated by BART compliance can be traded to BART-ineligible sources. For reasons of cost, administrative simplicity and compliance flexibility it may often make more sense to expand and/or modify existing programs to ensure that multiple policy goals – including visibility goals – are being served than to layer a new program on top of existing ones. The 1999 regional haze rule anticipates this possibility and provides for the substitution of source-by-source BART approaches with cap-and-trade or other regulatory alternatives. Importantly, such alternatives may be substituted for the standard BART approach only if they can be shown to provide *greater* benefits in terms of progress toward national visibility goals. Cap-and-trade alternatives would not necessarily preclude the application of BART to specific sources to address their particular contribution to visibility impairment in a given Class I area under "reasonable attribution" BART requirements and thus local "hot spots" may be exempt from participating in a trading mechanism.

A. SO_2 Reductions and Title IV (Acid Rain Program) Requirements

The primary control program currently affecting SO_2 emissions is the national Acid Rain Program authorized under Title IV of the federal Clean Air Act.[72] The program was introduced in the CAA amendments of 1990 and is being implemented on a cap-and-trade basis that allows for the trading and banking of emissions allowances among affected sources.[73] As noted in the previous chapter, Title IV aims to cut national SO_2 emissions from power plants by 10 million tons from 1980 levels, to an eventual cap of just under 9 million tons annually. Under the first phase of the program, power plant emissions fell by approximately 4 million tons annually to just over 13 million tons in 1998. Under Phase II, which began in 2000, a further reduction of approximately 4 million tons will eventually be required, though national power sector emissions are expected to remain at about 9.5 million tons for much of the decade because of the carryover of some 10 million excess allowances from Phase I. As detailed in the previous chapter, the application of modern scrubber controls (at 95

[72] Relatively modest SO_2 reductions were achieved prior to 1990 as the result of New Source Performance Standards and National Ambient Air Quality Standards for SO_2 required under the 1970 Clean Air Act.
[73] Note that Title IV also requires some power plants to reduce NO_X emissions. These requirements are briefly described in the next section.

percent control effectiveness) to all power plants that meet BART-eligibility criteria in the 29-state source region likely to affect visibility conditions in Northeast and Mid-Atlantic Class I areas, could produce over 5 million tons of annual SO_2 reductions. This represents roughly half of current SO_2 emissions from all power plants in the 29-state region and is greater than the total additional reductions that will be required for *nationwide* compliance with Title IV.

Applying BART on a source-by-source basis would shift the burden of Title IV compliance to BART-eligible units within the relevant source region but might not produce aggregate reductions beyond those anticipated under the Acid Rain Program – either regionally or nationally. To the extent that excess allowances generated by BART implementation were transferred to other BART-ineligible facilities within the source region, desired visibility benefits in Northeast and Mid-Atlantic Class I areas would be offset – potentially to a significant degree. To the extent that excess allowances were transferred outside the source region, other Class I areas in the West and Southeast would be subject to excess SO_2 emissions and to continued visibility impairment. Nationally, SO_2 emissions from all sources (including mobile and other individual sources as well as power plants) could remain well above 10 million tons, a level of emissions that is unlikely to allow for the restoration of "pristine" or near pristine visibility conditions almost anywhere in the country. In reality, of course, other regions will almost certainly need to implement further SO_2 reductions to address their own haze problems. For example, the nine-state Western Regional Air Partnership (WRAP) is considering emission reduction milestones for reducing SO_2 emissions from large industrial sources over the next 20 years, including a milestone reduction of 170,000 tons beyond what will otherwise be required under existing regulatory programs by 2018 (USEPA, 2000).

Thus, visibility considerations are likely to argue for aggregate SO_2 reductions beyond those slated to be achieved by Title IV. One obvious option for integrating those reductions with the current program is simply to lower the Acid Rain Program cap while leaving existing mechanisms for trading, retiring and tracking allowances in place. These mechanisms are well established, have functioned smoothly to date, and are understood by state and federal regulators and affected industry alike. Meanwhile, the rationale for a lowering of the Title IV cap is reinforced by other policy considerations, chief among them a growing concern that the current program – for all its success in reducing compliance costs and motivating early over-compliance – does not adequately address the problem it was intended to correct. Despite emissions reductions achieved to date, researchers investigating acid deposition in the Northeast continue to document adverse impacts on sensitive ecosystems:

> "Although uncertainties remain, our analysis indicates that current regulations will not adequately achieve the desired outcomes of the 1990 CAAA. Those desired outcomes include greater ANC (acid neutralizing capacity) for lakes and streams, greater diversity and health of fish populations, and less degradation of forest soil and stress to trees."
>
> --Driscoll et al., 2001

Since 1995, several reports have come to similar conclusions about the failure of Title IV to adequately protect sensitive forests and aquatic ecosystems from the damage caused by acidified soils and surface waters (USEPA, 1995; NAPAP, 1998; NESCAUM, 1999; GAO, 2000; ESA, 2000). These reports paint a consistent picture of soils that, because of their reduced acid neutralizing capacity (ANC), are no longer able to buffer deposited sulfates and nitrates. The fact that many soils are also approaching nitrogen saturation limits further limits their ability to counteract the acidification of surface waters. Thus, despite substantial power plant SO_2 reductions and a corresponding decline in sulfate deposition, surface water acidity and attendant environmental damage remains a problem at many locations throughout the Northeast.[74]

Recent studies have confirmed previous reports and have detailed the specific mechanisms involved in ecosystem damage from acid deposition (Hubbard Brook, 2001; Driscoll et al., 2001). Findings include:

- Acid deposition has accelerated the leaching of base cations – elements such as calcium and magnesium that help counteract acid deposition – from the soil in acid sensitive areas of the Northeast,

- Acid deposition has increased the concentration of dissolved aluminum in soil waters. Dissolved inorganic aluminum is an ecologically harmful form of aluminum. At high concentrations, aluminum can hinder the uptake of water and essential nutrients by tree roots,

- Acidification of soils leaches calcium from foliage of red spruce rendering them more susceptible to freezing injury. Increased freezing injury has lead to the mortality of more than half of large canopy red spruce trees in some forests in the Northeast,

- Extensive mortality among sugar maples in Pennsylvania appears to result from deficiencies of base cations, coupled with other stresses such as insect defoliation or drought. The data show that sugar maples are most prone to die on sites where base cation concentrations in soil or foliage are lowest,

- Forty-one percent of lakes in the Adirondack Mountain region of New York and 15 percent of lakes in New England exhibit signs of chronic and/or episodic acidification,

- Only modest improvements in ANC, an important measure of water quality, have occurred in New England. No significant improvement in ANC has been measured in the Adirondack or Catskill Mountains of New York,

- Elevated concentrations of aluminum, which is toxic to marine life, have been measured in acid-impacted surface waters throughout the Northeast,

- Given the loss of acid-neutralizing base cations and the accumulation of sulfur and nitrogen in the soil, many ecosystems are now more sensitive to the input of additional acids and recovery from acid deposition will likely be delayed, and

- Long-term research suggests that deeper emissions cuts will lead to greater and faster recovery from acid deposition in the Northeast.

[74] Canadian studies have shown similar problems in southeastern Canada, despite the fact that SO_2 emissions have been reduced by over 50 percent from1980 levels in eastern Canada (Acidifying Emissions Task Group, 1997).

Another compelling rationale for further controlling SO_2 emissions from power plants is the need to reduce human exposure to fine particle pollution. A considerable body of epidemiological evidence links ambient fine particle pollution to increased rates of morbidity and premature mortality from cardiac and respiratory ailments. In the East, the predominant constituent of fine particles is sulfate resulting from emissions of SO_2. The relationship between visibility improvement and future implementation of the new National Ambient Air Quality Standard (NAAQS) for fine particle matter ($PM_{2.5}$) is taken up separately in Section C of this chapter.

Concern about continued problems of acid deposition and new awareness of the health risks of fine particle pollution have prompted growing interest on the part of many state and federal policymakers in further lowering the national SO_2 cap for power plants. For example, a variety of bills have been introduced in Congress, some of which propose further SO_2 cuts of as much as 75 percent from Title IV levels as part of a comprehensive, multi-pollutant strategy for reducing health and environmental impacts from the power sector.[75] (As noted previously, applying BART to all eligible power plants in the preliminary 29-state source region for Northeast and Mid-Atlantic Class I areas would reduce total power sector emissions in the same region by about 50 percent from current levels.) Other proposals suggest a further 50 percent reduction in the 9 million-ton cap targeted under Title IV. Meanwhile, a number of northeastern states have moved forward with additional SO_2 reduction requirements for the most polluting facilities within their jurisdictions. New York, Massachusetts and Connecticut have either promulgated or proposed new regulations to reduce SO_2 emissions by a further 30 to 50 percent below current requirements.[76]

Regardless of the interaction with other state and federal control programs for SO_2, the 5 million tons of SO_2 emissions reductions that might be achieved through BART represents less than one-quarter of the national inventory. Therefore, achieving natural visibility conditions over the next 6 decades, will entail moving beyond BART and identifying ways to eliminate virtually all sulfur dioxide emissions attributable to humans. While the BART program represents an excellent opportunity to achieve short-term emissions reductions (i.e. over the next decade), emissions reductions from BART-ineligible power plants as well as other industrial and mobile sources ultimately will have to be achieved in order to restore pristine visibility conditions in all Class I areas. Further, emissions from Canadian sources that impact Class I areas in the U.S. will have to be addressed.

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[75] A 75 percent reduction from 1998 SO_2 emissions translates to a national cap for power plants of between 3 and 4 million tons.

[76] New York has proposed to phase in a 50 percent reduction in annual SO_2 emissions (beyond current requirements) between 2005 and 2008. Massachusetts has issued a two-step SO_2 reduction plan for six Massachusetts power plants. The first phase of emissions reductions will take effect on October 1, 2004 (or 2006 depending on the compliance path selected) with 12-month rolling average emissions capped at 6.0 lbs/MWh. The second phase takes effect October 1, 2006 (with an option for a 2008 compliance path) and establishes a monthly cap at 6.0 lbs/MWh and lowers the 12-month rolling average cap to 3.0 lb/MWh. In May 2000, Connecticut Governor John G. Rowland issued an executive order that calls for the reduction of SO_2 emissions 70 percent below current commitments prior to May 1, 2003. The Connecticut plan consists of two phases. The first phase applies to 61 units and requires SO_2 reductions of 18,893 tons/year by January 1, 2002 (50 percent reductions in fuel sulfur or equivalent). Phase 2 applies to 23 units and results in reductions of 8,900 tons/year (70 percent reductions in fuel sulfur or equivalent) by January 1, 2003.

B. NO_X Reductions and the NO_X SIP Call

Current regulatory programs aimed at reducing NO_x emissions are motivated primarily by ozone attainment needs and, to a lesser extent by acid deposition concerns. For example, the Acid Rain Program requires relatively modest power plant NO_x reductions, totaling approximately 2 million tons annually. As with SO_2, new power plants have been subject to New Source Performance Standards (NSPS) for NO_x since the 1970s. However, the imposition of NO_x limits on the much larger population of existing boilers has been a relatively recent development. The most significant near-term regulatory driver for reducing power plant NO_x emissions in the eastern U.S. is the so-called "NO_x SIP call" and related actions, including an Ozone Transport Commission Memorandum of Understanding (OTC MOU) affecting major sources in the Northeast and individual state petitions seeking mitigation of ozone transport under Section 126 of the CAA.[77] The NO_x SIP call was promulgated by USEPA in 1998 following a two-year effort by the multi-state Ozone Transport Assessment Group (OTAG) to explore causes and possible remedies for the transport of ozone and its precursors in the eastern U.S. It requires that substantial NO_x reductions be implemented across a 19-state region starting in May 2004.[78] Because the NO_x SIP call, OTC MOU and Section 126 petitions are all geared to reducing ozone they require emissions reductions only during the summer months when meteorological conditions are conducive to ozone formation (i.e. May 1 through September 30). By contrast, reductions required by the Acid Rain Program are annual.

Under the NO_x SIP call, states will be required to meet a summertime NO_x emissions limit, or budget, specified by USEPA. Budgets are calculated taking into account anticipated load growth and available, cost-effective control technologies.[79] Large fossil-fired steam electric boilers are assumed to be capable of reducing their NO_x emissions rates to 0.15 lb/mmBtu, a roughly 85 percent reduction from typical uncontrolled emissions for large coal-fired boilers. However, the NO_x SIP call does not specify how states must achieve their budgets, it requires only that they submit implementation plans demonstrating that they will do so. It has been widely assumed that most of

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[77] The OTC MOU committed participating Northeast and Mid-Atlantic states to go beyond existing Reasonably Available Control Requirements (then required in ozone non-attainment areas) and to produce further major point source NO_X reductions of 55-65 percent by 1999 and 65-75 percent by 2003. Following the end of the OTAG process, several individual northeastern states petitioned USEPA under Section 126, which authorizes states to seek relief from the impacts of transported pollution. The remedy proposed in response to these petitions was essentially equivalent to implementation of the NO_X SIP call, which is authorized under a separate section of the CAA (Section 110) authorizing USEPA to initiate remedies against pollution transport.

[78] Note that the original NO_X SIP call included 22 states and the District of Columbia and set an implementation date of May 2003. As a result of litigation Wisconsin was subsequently excluded from the NO_X SIP call and the implementation date for other states was delayed to 2004. In addition, Alabama and Michigan were given the option of excluding portions of two other states and submitting partial SIPS. Finally, USEPA is currently still reviewing the applicability of the NO_X SIP call to Missouri and Georgia. As a result, budgets for these states and/or compliance deadlines may change. Importantly, the implementation dates for remedies under individual state Section 126 petitions is 2003; meaning that some plants will continue to need to install controls in the original SIP call timeframe.

[79] To calculate NO_X budgets, USEPA first estimated baseline 2007 NO_x emissions taking into account load growth and existing regulatory requirements. Besides the 0.15 lb NO_x /mmBtu emissions rate applied to large steam electricity generating units, the following emissions reductions were assumed to be achievable for other types of units: boilers and turbines - 60 percent decrease, stationary internal combustion engines - 90 percent decrease and cement manufacturing plants - 30 percent decrease. The amount of NO_x emissions remaining in the state after application of controls to the affected source categories constitutes the 2007 budget

the reductions necessary to comply with SIP call budgets will be obtained from the power sector using market-based approaches similar to those of the Acid Rain program (including trading within and between states) to reduce compliance costs and provide flexibility.[80] Table VI-1 identifies the specific states included in the SIP call and indicates the total NO_x reductions each will have to achieve to comply with SIP call budgets. For comparison, the table also provides estimates of the summertime (ozone season) NO_x reductions achievable through a source-by-source application of BART to eligible power plants, based on the methodology and assumptions outlined in the previous chapter.[81] As has already been noted, a considerable fraction of required NO_X SIP call reductions can be achieved through summertime implementation of the BART program.[82]

[80] Specifically, USEPA has encouraged states to develop a NO_x Budget Trading Program for large stationary sources to promote cost-effective compliance with SIP call requirements and has provided guidance on a number of related market mechanisms. For example, states are encouraged to allow the banking of excess allowances, subject to certain limitations designed to prevent significant variability in levels of transported NO_x and ozone. For example, if states in the program bank allowances totaling more than 10 percent of the total program budget, a flow control mechanism will be instituted which limits the fraction of a source's banked allowances that can be used at full value. Any allowances used above that limit are discounted 2:1 providing an incentive to limit the use of banked allowances.

[81] Summertime estimates of NO_X emissions reductions were obtained by applying monthly emissions information from the 1998 Emission Tracking System/Continuous Emission Monitoring (ETS/CEM) database (available online: http://www.epa.gov/ttnotag1/areas/etscem.htm) to the annual estimates of NO_X emissions reductions presented in Chapter V (See Table V-4).

[82] This is perhaps not surprising, given that both SIP call budgets and BART-eligible reduction estimates were calculated using similar assumptions about the effectiveness of available control technologies. Based on recent experience with advanced post combustion controls – notably selective catalytic reduction (SCR) systems – the BART analysis in this report makes somewhat more aggressive control effectiveness assumptions, but this is balanced by the fact that not all units are BART-eligible.

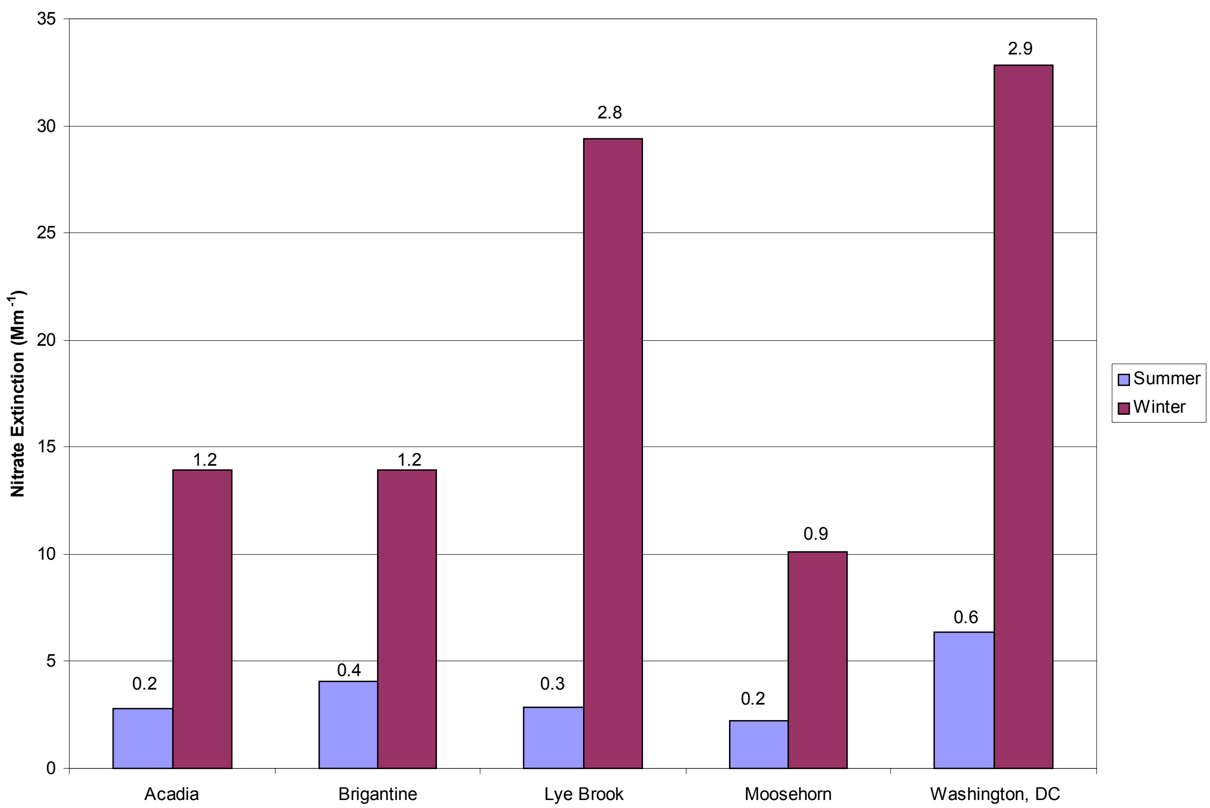
TABLE VI-1: Ozone season emissions budgets and reductions under the NOx SIP call.

State	NOx SIP Call Budgets[a] (tons)	Ozone-Season NOx SIP Call Reductions[a] (tons)	Ozone-Season NOx Reductions Obtainable Through BART[c] (tons)
Alabama	172,619	64,954[b]	28,859
Connecticut	42,849	3,166	3,088
Delaware	22,861	937	2,185
District of Columbia	6,658	0	406
Georgia	188,572	63,582 [b]	47,456
Illinois	270,560	98,310	89,798
Indiana	229,965	110,689	70,467
Kentucky	162,272	75,143	83,949
Maryland	81,898	21,578	19,610
Massachusetts	84,848	2,244	10,846
Michigan	229,702	63,118 [b]	38,332
Missouri	125,603	62,242 [b]	60,516
New Jersey	96,876	8,613	6,016
New York	240,288	15,365	15,212
North Carolina	165,022	59,675	60,599
Ohio	249,274	123,949	108,018
Pennsylvania	257,592	87,609	57,171
Rhode Island	9,378	85	0
South Carolina	123,105	29,700	21,558
Tennessee	198,045	58,720	41,220
Virginia	180,195	30,589	12,091
West Virginia	83,833	92,866	70,014
Wisconsin	135,771	38,463 [b]	15,467
Total	**3,357,786**	**1,111,597**	**862,878**

Notes:
a.) These are the original NOx SIP call budgets and required reductions; however, these numbers will change to reflect the control level for large internal combustion engines. Source: Summary of EPA's Approach to the NOx SIP Call in Light of the March 3rd Court Decision, April 11, 2000.
b.) As a result of litigation (see Footnote 78), Wisconsin has been excluded from the SIP call and will have no budget or reduction requirements. The emissions budgets for Georgia, Missouri may be substantially reduced to reflect that portions of those states are no longer subject to the SIP call. USEPA plans to propose revised budgets for Alabama and Michigan of 124,795 and 191,941 tons respectively. These changes will result in NOx reductions for Alabama and Michigan of 44,361 and 53,988 tons respectively. Including these changes and eliminating Wisconsin will result in a total of approximately 1 million tons of required emissions reductions under the SIP call.
c.) SIP call reductions are required for the ozone season only whereas BART emissions reductions would be applied on an annual basis, thus states would typically achieve twice the tonnage reduction on an annual basis (see Table V-4).

This result suggests that, once implemented, NO_x SIP call requirements, and related regulations, will achieve overall NO_x reductions only slightly larger than those achievable by BART across a broadly comparable source region.[83] Importantly, however, NO_x SIP call budgets apply only during the summer months, whereas the nitrate contribution to visibility impairment is not only year-round, but arguably more significant in the wintertime when it accounts for as much as 10 percent of total light extinction experienced at Northeast and Mid-Atlantic Class I sites. To illustrate this point, Figure VI-1 shows a seasonal comparison of light extinction due to nitrate at IMPROVE sites in the region.

Figure VI-1: Seasonal comparison of nitrate contribution to visibility impairment at IMPROVE sites in the Northeast and Mid-Atlantic States



Note: The number at the top of each column represents the seasonal average nitrate contribution to fine particle *mass* in µg/m^3. Although nitrate contributions to visibility impairment are considerably larger during the winter, they remain a relatively small fraction of visibility impairment (generally <10%) relative to sulfate (60-80%).

In this context, the better approach to integrating visibility objectives with existing NO_x control programs (rather than simply layering BART requirements on top of those programs) may be to simply extend ozone season emissions limits to the other months of the year. This would effectively double the NO_x reductions achieved by the SIP call and other programs each year. And

[83] Note that some states not included in the SIP call may contribute to visibility impairment in Northeast and Mid-Atlantic Class I areas, based on the 29-state source region identified previously. These include Arkansas, Iowa, Maine, Minnesota, Mississippi, New Hampshire, and Vermont.

in addition to addressing the wintertime contribution of nitrate to visibility impairment, it would mitigate other public health and environmental problems associated with NO_x emissions: including fine particle pollution, acid deposition, nitrogen saturation (of soils) and the eutrophication of sensitive surface waters. Moreover, given that a certain level of investment in control technology is necessitated by summertime NO_x limits in any case, the cost of the incremental reductions achieved by running the same controls year-round is likely to be quite reasonable. In fact, a number of northeastern states have begun exploring, or have already proposed, to impose year-round NO_x control requirements on power plants within their borders.

C. Coordinating Visibility Improvement Efforts with $PM_{2.5}$ NAAQS Attainment

The recently promulgated National Ambient Air Quality Standard (NAAQS) for fine particulate matter ($PM_{2.5}$) is another regulatory program that will be closely linked to future efforts to implement the regional haze rule.[84] Because visibility impairment is caused by particles within the size range regulated under the new standards,[85] efforts to reduce haze will reduce fine particle pollution and vice versa. Because of the obvious synergy between the two programs, many of the statutory deadlines in USEPA's 1999 regional haze rule are explicitly tied to the designation of $PM_{2.5}$ non-attainment areas and to state submittals of $PM_{2.5}$ attainment plans.[86]

To assist with the implementation of the new $PM_{2.5}$ standard, a comprehensive monitoring network is being deployed to measure ambient concentrations of $PM_{2.5}$ across the country.[87] By helping to identify areas that do not meet the new fine particle standards, as well as likely sources and transport mechanisms for $PM_{2.5}$ in various regions, these monitoring activities will provide information directly relevant to future haze planning efforts. Based on the monitoring schedule and allowing time for data analysis, USEPA should be in a position to begin making $PM_{2.5}$ nonattainment designations in 2002 at the earliest.[88] Once USEPA designates non-attainment areas

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[84] The new standard applies to particles smaller than 2.5 micrometers in diameter or $PM_{2.5}$ and requires that both annual average mass concentrations and peak daily (24-hour) concentrations of $PM_{2.5}$ remain at or below 15 $\mu g/m^3$ and 65 $\mu g/m^3$, respectively. USEPA promulgated the fine particle NAAQS on the basis of extensive epidemiological data suggesting that fine particle pollution was linked to a number of adverse health effects including premature death; increased hospital admissions and emergency room visits (primarily by the elderly and individuals with cardiopulmonary disease); increased respiratory symptoms and disease (in children and individuals with cardiopulmonary disease such as asthma); decreased lung function (particularly in children and individuals with asthma); and with alterations in lung tissue and structure and in respiratory tract defense mechanisms.

[85] An older standard for particulate matter predated the more recent NAAQS and still applies. That standard applies to particulate matter up to 10 micrometers in diameter (PM_{10}). This larger size category includes particles outside the size range most associated with visibility impairment. Past violations of the PM_{10} standard were largely linked to sources such as windblown dust in desert or agricultural areas, to road dust and to problems with woodsmoke in certain locales.

[86] A detailed description of these linkages and of the timeline of regulatory requirements under the 1999 regional haze rule is provided in the earlier NESCAUM haze report (NESCAUM 2001).

[87] In fact, much of that network is already in place. It includes approximately 1300 monitors, all of which provide for gravimetric mass measurements of fine PM. In addition, at least 50 of the monitors will provide for a more comprehensive speciation of the particles into their constituent components. (See further discussion in the previous NESCAUM report.)

[88] If necessary to meet CAA requirements, USEPA may issue "unclassifiable" designations that will not trigger planning or control requirements.

of the $PM_{2.5}$ standard, states will have three years to develop and submit implementation plans (SIPs) for bringing those areas into attainment. SIPs must demonstrate attainment within 10 years of designation, with the possibility of two 1-year extensions.

Consistent with the approach taken in the regional haze rule, USEPA has emphasized a regional approach to $PM_{2.5}$ NAAQS implementation, indicating that it will encourage states to work together to develop and implement regional control programs – including cap-and-trade programs similar to the one used in the Acid Rain Program (USEPA, 1997). In addition, the Agency has suggested that it will not require states to impose unnecessary local measures so long as they are doing their part to carry out regional reduction programs and so long as those programs (such as full implementation of Title IV[89]) can be expected to bring them into attainment. For states in non-attainment of new fine particle standards, the implementation of BART requirements under the auspices of the regional haze rule, especially on a regional basis, could make a substantial contribution toward required attainment demonstrations. Conversely, measures taken to achieve compliance with the new $PM_{2.5}$ NAAQS may constitute much of a given state's demonstration of "reasonable progress" toward visibility goals during the first regional haze compliance period (2008-2013).

Pollutants and sources other than those that have been emphasized in this report (i.e. SO_2 and NO_X emissions from power plants) contribute to both fine particle pollution and visibility impairment. These include organic compounds, elemental carbon (or soot), ammonium and crustal material (such as salt, soil and dust) that are emitted by a wide range of sources including automobiles, diesel engines, solvents and coatings, manufacturing processes and other industrial sources besides large steam electric boilers. Further reductions in these emissions from a variety of sources, including many source categories that are presently excluded from BART requirements, will certainly be necessary to restore pristine visibility conditions in Class I areas and, in many cases, to achieve compliance with $PM_{2.5}$ ambient air quality standards. Ultimately, the most important synergy between haze and $PM_{2.5}$ attainment programs may be the fact that visibility goals will provide impetus for ongoing efforts to reduce pollution from a wide range of sources, even after applicable NAAQS are attained. Given that there appears to be no threshold below which fine particle pollution is not detrimental to human health, such reductions are likely to continue to provide broad-based public health benefits. In many northeastern states, for instance, where $PM_{2.5}$ standards are already very close to being met, visibility obligations may provide an important rationale for sustained progress toward healthier air.

D. Cost Effectiveness of BART Control Technology Options

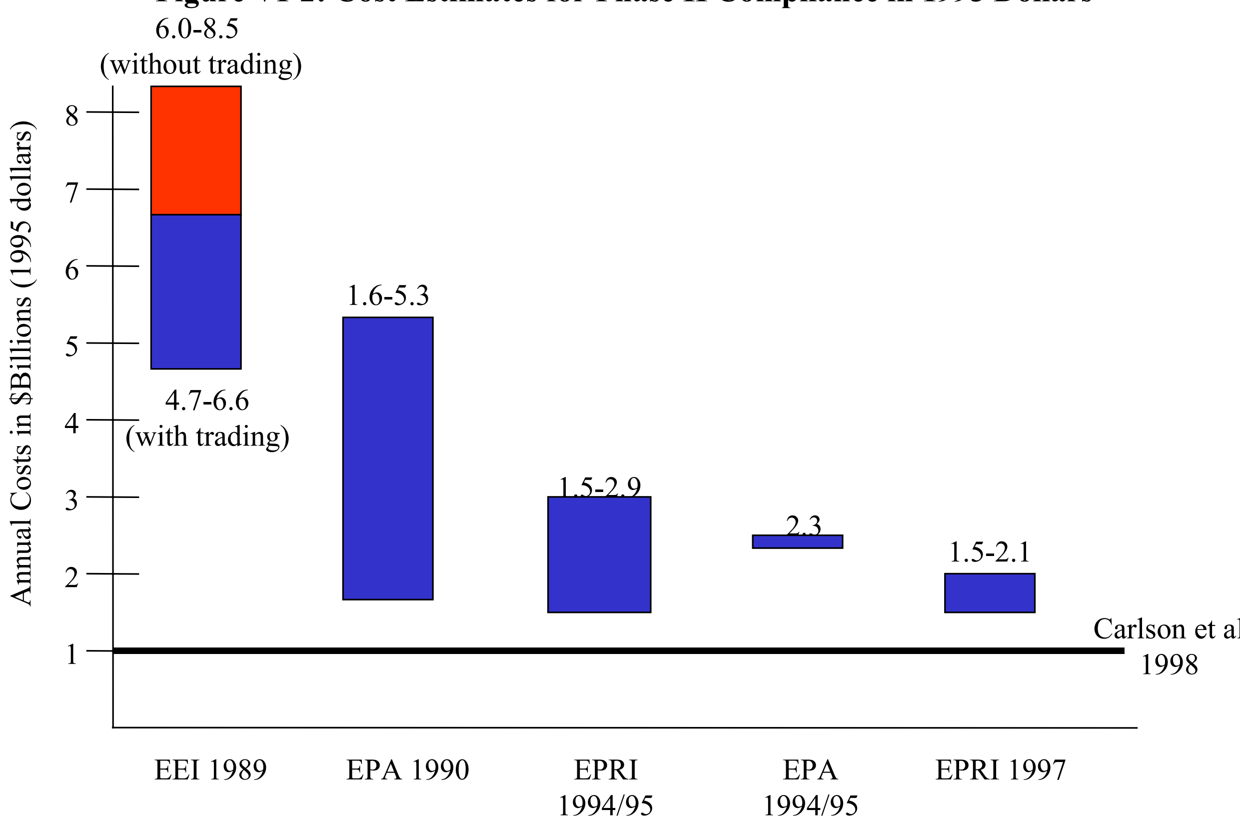
In general, the control technologies available for major point sources of SO_2 and NO_X have already been demonstrated as highly cost-effective. Flue gas desulfurization (FGD), the primary SO_2 control hardware for power plants, is a well-developed, commercially available technology. The actual cost of complying with Title IV Acid Rain Program requirements has been far lower than

[89] USEPA has projected that nearly one-third of the areas projected to be in non-attainment for $PM_{2.5}$ could come into attainment as a result of the regional SO_2 emission reductions already mandated under the federal Acid Rain Program.

pre-implementation predictions by both regulators and industry. Figure VI-2 demonstrates how Phase II compliance costs have dropped from initial estimates of 5-8 billion dollars in 1989 to around 1 billion dollars (NESCAUM, 2000). Due to technological advancements, increased operational efficiency and program compliance flexibility, the cost of SO_2 allowances has been consistently below $200 per ton for the last several years. While allowance costs are expected to rise with a further tightening of applicable emissions caps, it remains likely that the additional reductions discussed in this report (i.e. on the order of a further 50 percent reduction) can be achieved at costs well below those predicted in the late 1980s and early 1990s for the existing Acid Rain program.

Similar declines in control costs have occurred and are expected to continue for NO_X reductions from power plants and other large sources. Previous NESCAUM assessments of the state of available NO_X control technologies (such as SCR, selective non catalytic reduction (SNCR), and natural gas and coal reburn) have shown that capital costs, as well operating and maintenance costs, have declined substantially with the large-scale application of these technologies in the U.S. to address ozone and acid deposition problems (See Table VI-2). Existing information suggests that future NO_X reductions can be achieved at an annual cost of between $500 and $1,000 per ton (NESCAUM, 1998).[90] Operating existing controls beyond the ozone season is likely to be an especially cost-effective strategy for addressing year-round problems such as visibility impairment, acid deposition and nitrogen deposition, since in these cases the capital costs of installing control systems are largely sunk.

Figure VI-2: Cost Estimates for Phase II Compliance in 1995 Dollars



Source: Burtraw 1998; Smith, Platt et al. 1998

[90] Note that the difference between this estimated cost and that listed in Table VI-2 reflects market efficiencies that arise through the use of trading programs which allow emissions reductions to be obtained at the most cost-effective sites.

Table VI-2: SCR early engineering costs estimates versus current costs (1999 dollars; based on a 500 MW, wall-fired boiler)

Study	Capital Costs ($/kW)	Cumulative % Decrease	$/ton	Cumulative % Decrease
EPRI 1985[a]	90-155[d]		2,800-11,290	
EPRI 1989[b]	125	None	2,500-5,000	4-55
NESCAUM 1998[c]	50-75	40-60	1,000-1,100	64-90

Notes:
a) Miller, EPRI Coal Combustion Systems Division et al. 1985.
b) Eskinazi, Cichanowicz et al. 1989.
c) NESCAUM, 1998.
d) Retrofit factor of 1.24

In general, past regulatory experience suggests that technology innovation in response to firm environmental performance standards nearly always reduces control costs substantially below early expectations. Carefully designed regulatory programs that make appropriate use of market-based mechanisms, while providing flexibility and incentives for continued innovation can further reduce compliance costs. To the extent that future efforts to implement BART and other visibility-based pollution reduction programs can be integrated and rationalized with existing regulations, economic efficiency will be enhanced, as will public support for the continued emission reduction efforts needed to achieve national visibility goals.

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VII. Conclusion

On most days, visibility in Northeast and Mid-Atlantic Class I areas is substantially degraded relative to "pristine" natural conditions. Average visual range in the region is only 72 km at Moosehorn Wilderness Area in Maine and a mere 37 km at the Brigantine Wilderness Area in New Jersey. These figures compare to an estimated average visual range of 163 km which should be experienced across the region under unpolluted conditions. In this context, and given the number and variety of emissions sources that contribute to regional haze, achieving national visibility goals presents a formidable challenge for policymakers, affected industry and the public.

As first steps toward meeting national visibility goals, states, tribes and regional planning organizations will need to further refine their efforts to identify geographic source regions, assess the contribution of different emissions sources and evaluate control strategies – including analyzing in more detail the reductions achievable through the BART program for power plants and other potentially eligible source categories. However, as this report and NESCAUM's previous assessment of regional haze in the region also indicate, future planning efforts can draw from a considerable foundation of existing information. Further research is probably not needed, for example, to conclude that sulfate plays a major role in visibility impairment throughout the East and that further reductions in SO_2 emissions present an obvious area of opportunity for near-term progress in mitigating haze. Similarly, the different analyses described in Chapter IV present a compelling weight-of-evidence case for concluding that the geographic source region for visibility impairing pollutants in Northeast and Mid-Atlantic Class I areas extends at least as far west and south as the Ohio River and Tennessee Valley areas.

Having identified preliminary source regions and emissions reduction opportunities, the challenge of building consensus on a regulatory framework which advances visibility goals, reduces public health threats and other types of environmental harms, and is acceptable in both economic and political terms remains. Typically, industry desires regulatory certainty and flexibility in compliance, while environmental and public health advocates want to ensure adequate standards for protecting health and natural resources. State and federal agencies are charged with designing a framework for emissions control that balances the interests of both constituencies. These challenges are made more difficult when considering the potential interactions between various existing regulatory programs, each of which is designed to address a specific environmental or public health threat.

Recently several groups have called for a "one atmosphere" approach to air quality management that considers all potential threats to public health and the environment and regulates in a manner designed to achieve multiple objectives using a unified and consistent approach. This approach may provide a useful paradigm for integrating future BART implementation efforts with other regulatory programs and for longer-term haze mitigation efforts generally. To maximize the benefits and minimize the costs of these efforts, policymakers and regulators should consider:

- Establishing a single trading currency for each pollutant subject to trading programs,

- Strengthening caps while maintaining existing market mechanisms that deliver flexibility and encourage cost-effective pollution control strategies,[91]

- Ensuring that future regulations provide incentives for continued technological innovation, early compliance, and over-compliance,

- Promoting strategies that reduce emissions of multiple pollutants simultaneously, and

- Developing regulatory assessment methodologies that account for multi-pollutant benefits (both in the sense that reducing one type of pollutant may have multiple public health and environmental benefits, and in the sense that some control strategies may reduce multiple types of pollution).

In addition to these general recommendations for future control programs, specific actions by the USEPA should be taken now to ensure that the BART control measures described in the proposed guidelines remain a strong and binding means of reducing the environmental and public health threats presented by fine particle pollution while improving the quality of life in our wild lands and in our urban centers. USEPA should:

- Maintain the BART presumptive level of control for SO_2 emission sources at 90-95 percent control efficiency (equivalent to the installation of best available FGD control technology).

- Establish a BART presumptive level of control for NO_X emission sources at 94 percent control efficiency (equivalent to the installation of a combination of best available low-NO_X burner and SCR control technology).

- Provide additional specificity with regard to what constitutes a “non-trivial” contribution to downwind visibility impairment.

- Provide additional specificity with regard to what constitutes “unreasonable” compliance costs, “unacceptable” energy impacts, and “unacceptable” other non-air quality environmental impacts.

- Provide additional specificity with regard to how alternative trading programs would interact with existing regulatory programs including how geographic considerations would factor into trading mechanisms (e.g. geographic restrictions on inter-RPO trading or intra-RPO trading between BART-eligible and BART-ineligible sources).

[91] Note that, depending on the geographic area included in the trading program, additional measures may be needed to ensure that enough of the reductions achieved under that program occur where they will provide the desired level of air quality improvement, whether with respect to downwind visibility conditions or fine particle NAAQS attainment. In addition, growing awareness of more localized pollution impacts and environmental justice concerns has increasingly led community groups and public health advocates to insist that a minimum level of pollution control be applied at certain facilities. These issues will need to be carefully considered in updating and possibly modifying some market-based programs, especially those – like the Acid Rain Program – that are national in scope.

The MANE-VU RPO is preparing formal comments on the recently published BART guidelines on behalf of its member states and tribes. These comments will address all of the issues identified in this report and provide suggested language for remedying deficiencies in the current rule. In addition to the issues raised here, many other issues must be addressed in order to construct an effective control program to aid in achieving the visibility goals described in the regional haze rule. However, given our fairly complete understanding of the major sources of visibility impairment in the East and the availability of cost-effective controls, initial planning efforts for regional haze mitigation should not be delayed while final details of the BART program are debated.

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Appendix A: SO_2 Emissions from BART-Eligible Sources

In order to estimate the potential SO_2 emissions reductions that might be obtained by applying BART to eligible sources located in the preliminary 29-state source region, data from several sources were obtained and analyzed. These data were first cross referenced to obtain all the parameters needed to test for BART-eligibility. Subsequently, information regarding current controls and emissions was used to estimate potential emissions reductions.

The USEPA 1999 Emissions Scorecard database outlines the acidic precursor emissions and carbon dioxide emissions of all Title IV affected power plants (USEPA, 2001). It contains the plant name, plant orispl code, unit ID, associated stack status (e.g. retired, not operating, etc.), SO_2 phase, NO_X phase, boiler type, fuel type, heat input (mmBtu), 1999 NO_X rate (lbs/mmBtu), 1999 emissions of SO_2, NO_X, CO_2 (all in tons), as well as information regarding control technology currently installed on each unit. To determine BART-eligibility, the date that each unit commenced operation was obtained from three primary sources. The EIA99 database and the EGU8 database were provided by USEPA's Clean Air Markets Division (Sun, 2000). In addition, the EIA-767 database was obtained online (EIA, 2001). All three databases contain plant orispl code, unit ID and the year that the plant commenced operation. The dates of operation were cross-referenced with the 1999 Emissions Scorecard information using the plant orispl code and unit ID to identify those units which began operating between 1962 and 1977.[92] Finally, the current control efficiency of those sources with scrubbers was determined using Table 30 from the Energy Information Administration (EIA), Form EIA-767 (Dean, 2001). This information represents the state of controls as of 1998.[93] Combining the information from these sources and following the methodology described below, a determination was made regarding each source's BART-eligibility.

The decision tree shown in Figure A-1 illustrates the process by which BART determinations were made. A total of 2,470 individual units had source classification codes (SCC) that began with the digits '101' indicating that they were fossil-fuel fired steam electric plants.[94] Of these, 1534 units were located within the 29-state source region reasonably anticipated to cause or contribute to visibility impairment in Northeast and Mid-Atlantic Class I areas. Using the dates contained in the EIA-767, EIA99 and EGU8 databases, 387 units were identified as having commenced operation between 1962 and 1977, however, it should be noted that some of these units may have commenced operation prior to August 7th of 1962 or after August 7th of 1977, rendering these units ineligible for BART. Without more specific information regarding the exact dates of operation for these units, we have assumed these sources are potentially BART-eligible.

These 387 sources were then checked to see whether they met heat input and SO_2 emissions criteria for BART-eligibility. Following the BART guidance, the combined heat input from all units

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[92] On occasion, the date listed for a particular unit in the EGU8 database differed from that listed in the EIA99 or EIA-767 database. If any of these dates were between 1962 and 1977 the unit was considered to satisfy the BART age criterion.

[93] Recently released information for 1999 indicate that five BART-eligible units have installed control technology that has not been reflected in the current analysis. These include: Cayuga 1 (at 95 percent control efficiency), Cayuga 2 (95 percent), Hamilton 9 (90 percent), HMP&L Station 2 H1 (95 percent), and HMP&L Station 2 H2 (95 percent).

[94] In accordance with USEPA guidance (USEPA, 2001), simple cycle turbines should be eliminated from this category as these plants generally do not produce steam and are not considered "BART-eligible". None of the units from this category which satisfy age criteria for BART-eligibility were simple cycle turbines.

at a source which began operation during the 15 year BART time window were compared to the 250 mmBtu/hr threshold and the combined emissions from all such units were compared to the 250 ton emission threshold (USEPA, 2001). The EIA-767 database contains the design capacity of units which allowed the inclusion of units that were found to operate below 250 mmBtu/hr, but have the potential to exceed this threshold. Units have been flagged if their design capacity was unknown, or if the combined emissions (from all units at a source within the BART-eligible time window) were less than 250 tons in 1999. These units may be BART-eligible, but we were unable to exclude them based on the available information. In total, 387 units were found that meet the criteria for BART-eligibility; these are listed individually with their SO_2 emissions and associated controls in Table A-1. Flagged units are shown in the Table A-1 in red. Green text is used to denote units which may be BART-eligible, but did not operate in 1999, the year used for the current analysis.

We assume 95 percent control efficiency can be achieved at the 365 units that are currently uncontrolled. Of the 41 units with scrubber technology, 21 units operate at 95 percent control efficiency. We estimate that additional emissions reductions can be achieved at the 20 units with scrubbers that do not currently achieve 95 percent control efficiency and assume that a resulting control efficiency of 95 percent can be achieved after application of additional BART measures. Figure A-2 shows the process for assessing potential SO_2 emissions reductions from each of the 387 BART-eligible units identified.

Based on the analysis described it is estimated that SO_2 reductions of approximately 5 million tons could be achieved by implementing BART in the likely source region for visibility impairing pollutants found at Northeast and Mid-Atlantic Class I areas.

Figure A.1: Decision Tree for Determining BART-eligible Boilers

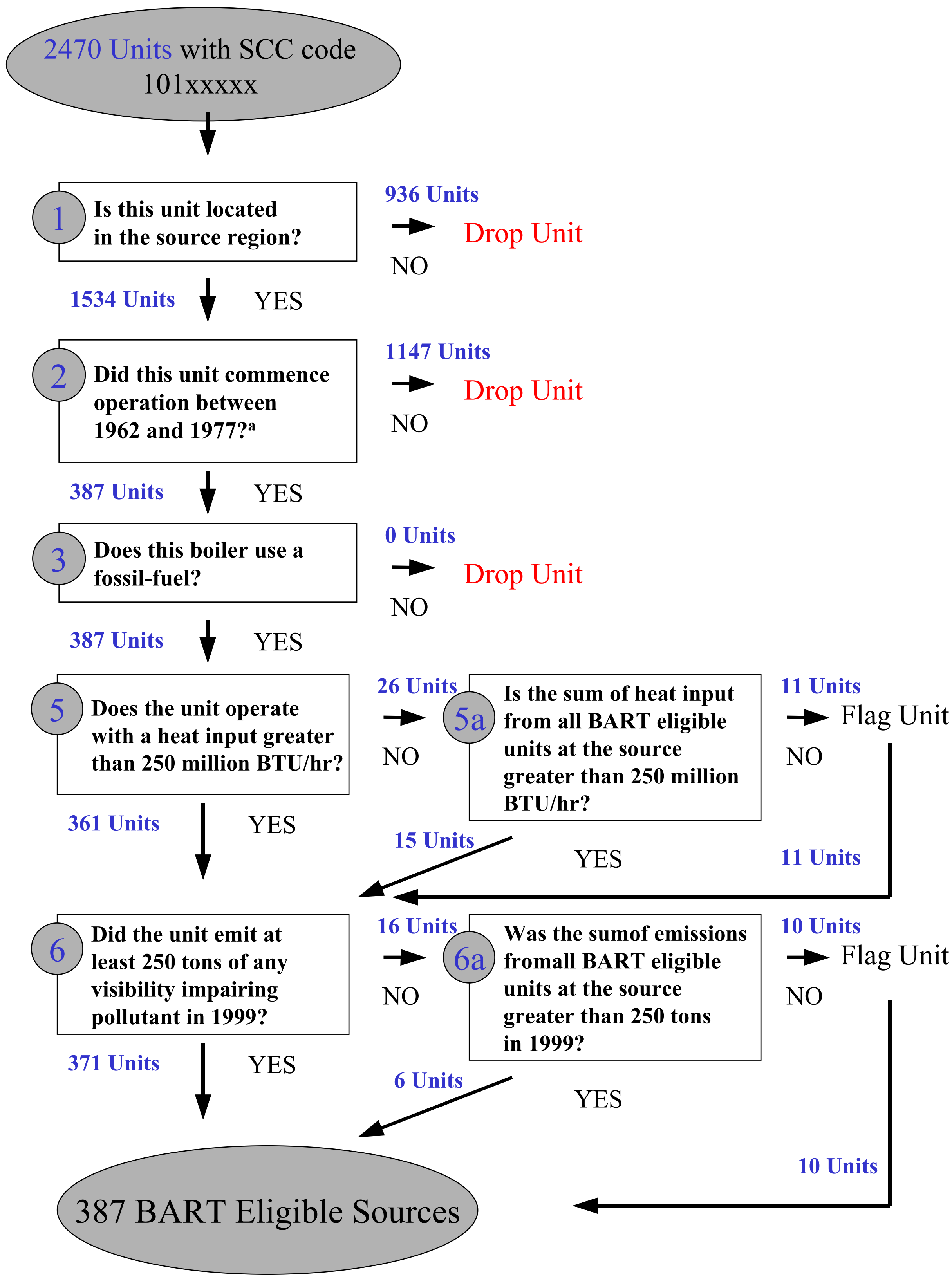

Figure A.2: Decision Tree for Determining Potential SO_2 Emissions Reductions

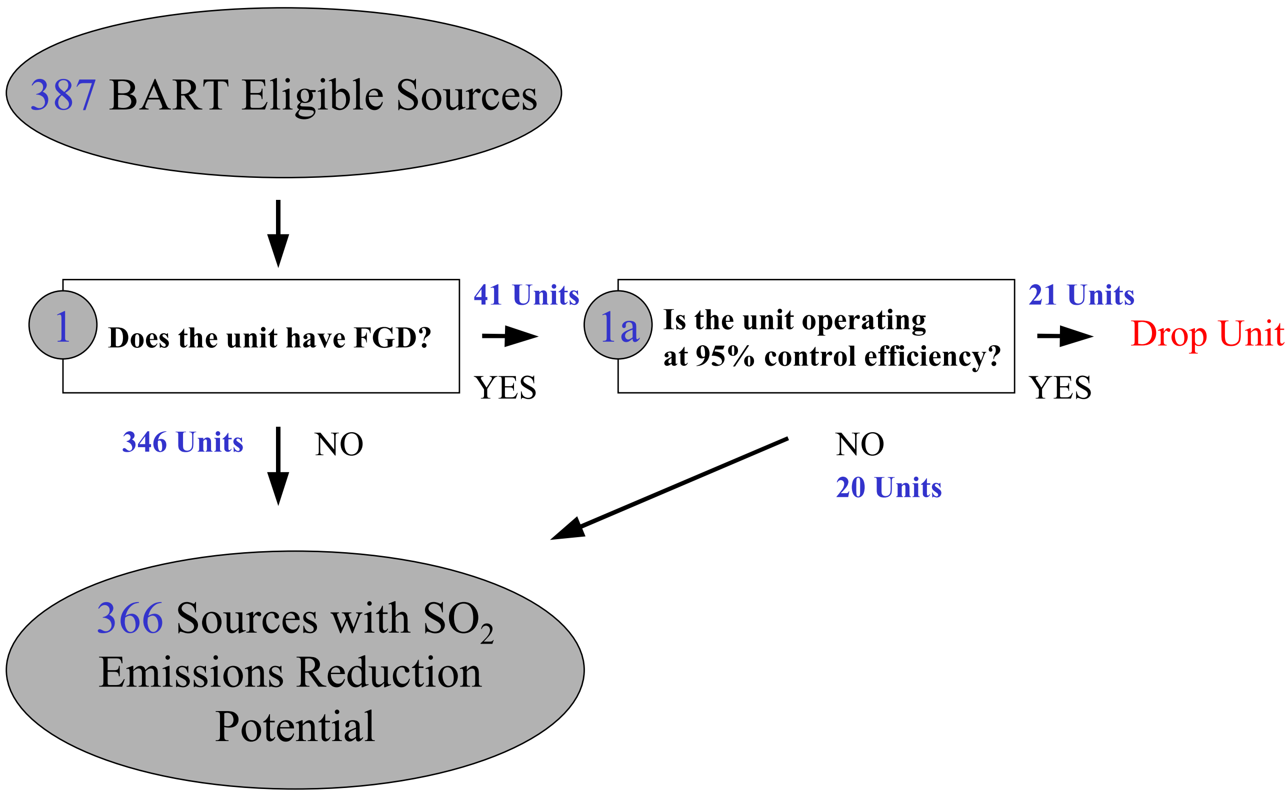

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Table A-1: SO_2 Emission Information from 387 Potentially BART-eligible Boilers located in the preliminary geographic source region of influence for Class I areas in the Mid-Atlantic and Northeast U.S.

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Alabama	Barry	3	4		1969	1969	1969	T	C	U		16,527.0	3,334.1	15,701	826.35
Alabama	Barry	3	5		1971	1971	1971	T	C	U		29,809.9	6,115.0	28,319	1,490.50
Alabama	Charles R Lowan	56	1		1969	1969	1969	DB	C	U		4,661.6	463.4	4,429	233.08
Alabama	Colbert	47	5		1965	1965	1965	DB	C	U		46,972.2	2,983.6	44,624	2,348.61
Alabama	E C Gaston	26	4	CS0CBN	0	1962	1962	DB	C	U		13,468.0	1,990.5	12,795	673.40
Alabama	E C Gaston	26	5		1974	1974	1974	T	C	U		43,507.6	6,288.6	41,332	2,175.38
Alabama	Gorgas	8	10		1972	1972	1972	T	C	U		41,946.7	4,761.6	39,849	2,097.33
Alabama	Greene County	10	1		1965	1965	1965	CB	C	U		24,785.9	1,760.9	23,547	1,239.30
Alabama	Greene County	10	2		1966	1966	1966	DB	C	U		32,024.3	2,242.9	30,423	1,601.22
Alabama	Widows Creek	50	8		1965	1964	1965	T	C	WLS	80.0	10,054.6	3,674.5	119	9,935.20
Alabama Total:												**263,757.8**		**241,137.5**	**22,620.4**
Arkansas	Carl Bailey	202	1		1966	0	0	DB	G	U		65.4	315.6	62	3.27
Arkansas	Lake Catherine	170	4		1970	0	1970	DB	G	U		5.4	2,073.7	5	0.27
Arkansas	Mcclellan	203	1		1972	0	0	DB	G	U		583.3	433.1	554	29.16
Arkansas	Robert E Ritchie	173	2		1968	0	1968	T	G	U		2.9	1,146.7	3	0.15
Arkansas	Thomas Fitzhugh	201	1		1963	0	0	DB	G	U		4.1	133.3	4	0.21
Arkansas Total:												**661.1**		**628.0**	**33.1**
Connecticut	Middletown	562	3		1964	0	1964	C	O	U		862.7	879.4	820	43.14
Connecticut	Middletown	562	4		1973	0	1973	T	O	U		2,559.0	1,290.8	2,431	127.95
Connecticut	Montville	546	6		1971	1971	1971	T	O	U		3,590.3	1,157.1	3,411	179.52
Connecticut	Norwalk Harbor	548	2	CS0001	1963	0	1963	T	O	U		3,518.8	917.0	3,343	175.94
Connecticut	WISVEST - Bridgeport H	568	BHB3		0	1968	1968	T	C	U		8,566.1	1,983.9	8,138	428.30
Connecticut	WISVEST - New Haven I	6156	NHB1		0	1975	1975	T	O	U		11,689.8	2,657.2	11,105	584.49
Connecticut Total:												**30,786.7**		**29,247.4**	**1,539.3**
Delaware	Edge Moor	593	4		1966	1966	1966	T	C	U		4,062.4	928.8	3,859	203.12
Delaware	Edge Moor	593	5		1973	1973	1973	DB	O	U		3,788.9	1,719.0	3,599	189.44
Delaware*	Indian River	594	3		1970	1970	1970	DB	C	U		1,987.5	203.7	1,888	99.38
Delaware*	Mckee Run	599	3		1975	1975	1975	DB	O	U		652.0	236.3	619	32.60
Delaware Total:												**10,490.8**		**9,966.3**	**524.5**
District of Columbia	Benning	603	15		1968	0	1968	T	O	U		757.0	195.6	719	37.85
District of Columbia	Benning	603	16		1972	1972	1972	DB	O	U		675.3	181.5	642	33.76
District of Columbia Total:												**1,432.3**		**1,360.7**	**71.6**
Georgia	Bowen	703	1BLR		0	1971	1971	T	C	U		28,631.1	4,625.2	27,200	1,431.55
Georgia	Bowen	703	2BLR		0	1972	1972	T	C	U		34,348.3	5,432.4	32,631	1,717.42
Georgia	Bowen	703	3BLR		0	1974	1974	T	C	U		37,294.2	5,904.8	35,429	1,864.71
Georgia	Bowen	703	4BLR		0	1975	1975	T	C	U		39,880.5	6,474.5	37,886	1,994.03
Georgia	Hammond	708	4		1970	1970	1970	DB	C	U		19,579.3	3,200.5	18,600	978.97
Georgia	Harllee Branch	709	1	CS001	1965	1965	1965	CB	C	U		14,448.7	1,529.7	13,726	722.43
Georgia	Harllee Branch	709	2	CS001	1967	1967	1967	DB	C	U		14,547.1	1,540.2	13,820	727.36
Georgia	Harllee Branch	709	3	CS002	1968	1968	1968	CB	C	U		23,628.5	2,617.9	22,447	1,181.43
Georgia	Harllee Branch	709	4	CS002	1969	1969	1969	CB	C	U		25,063.1	2,776.8	23,810	1,253.15
Georgia	Jack Mcdonough	710	MB1	CS001	0	1963	1963	T	C	U		12,403.0	1,784.6	11,783	620.15
Georgia	Jack Mcdonough	710	MB2	CS001	0	1964	1964	T	C	U		11,808.5	1,699.1	11,218	590.43

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Georgia	Kraft	733	3	CS001	1965	1965	1965	T	C/G	U		3,541.5	699.3	3,364	177.07
Georgia	Kraft	733	4	CS001	1972	1972	1972	T	O	U		1,092.2	215.7	1,038	54.61
Georgia	Mitchell	727	3		1964	1964	1964	T	C	U		4,429.5	527.6	4,208	221.48
Georgia	Wansley	6052	1		1976	1976	1976	T	C	U		43,289.5	5,916.1	41,125	2,164.48
Georgia	Yates	728	Y6BR		0	1974	1974	T	C	U		9,001.3	1,601.6	8,551	450.06
Georgia	Yates	728	Y7BR		0	1974	1974	T	C	U		10,446.6	1,818.2	9,924	522.33
Georgia Total:												**333,432.9**		**316,761.2**	**16,671.6**
Illinois	Baldwin	889	1		1970	1970	1970	C	C	U		65,230.5	2,952.4	61,969	3,261.53
Illinois	Baldwin	889	2		1973	1973	1973	C	C	U		91,310.0	4,127.3	86,745	4,565.50
Illinois	Baldwin	889	3		1975	1975	1975	T	C	U		88,702.7	3,974.8	84,268	4,435.14
Illinois	Coffeen	861	1	CS0001	1965	1965	0	C	C	U		18,619.9	1,996.5	17,689	930.99
Illinois	Coffeen	861	2	CS0001	1972	1972	0	C	C	U		28,991.4	3,108.6	27,542	1,449.57
Illinois	Collins	6025	2	CS1230	1977	1977	1977	DB	G	U		39.2	961.8	37	1.96
Illinois	Collins	6025	3	CS1230	1977	1977	1977	DB	G	U		45.0	1,104.8	43	2.25
Illinois	Dallman	963	31		0	1968	1968	C	C	U		15,174.1	627.0	14,415	758.70
Illinois	Dallman	963	32		0	1972	1972	C	C	U		13,185.4	542.5	12,526	659.27
Illinois	Duck Creek	6016	1		1976	1976	1976	DB	C	WLS	86.0	11,878.1	2,722.3	131	11,746.89
Illinois	E D Edwards	856	2		1968	1968	1968	DB	C	O		12,594.8	1,625.6	11,965	629.74
Illinois	E D Edwards	856	3		1972	1972	1972	DB	C	O		39,346.4	2,165.5	37,379	1,967.32
Illinois	Joilet 29	384	71	CS7172	0	1965	1965	T	C	U		3,919.4	1,377.2	3,723	195.97
Illinois	Joilet 29	384	72	CS7172	0	1965	1965	T	C	U		6,910.5	2,428.2	6,565	345.52
Illinois	Joilet 29	384	81	CS8182	0	1966	1965	T	C	U		4,303.9	1,508.0	4,089	215.19
Illinois	Joilet 29	384	82	CS8182	0	1966	1965	T	C	U		5,967.5	2,090.9	5,669	298.38
Illinois	Kincaid	876	1	CS0102	0	1967	1967	C	C	U		11,292.5	3,582.7	10,728	564.63
Illinois	Kincaid	876	2	CS0102	0	1968	1968	C	C	U		8,574.3	2,720.3	8,146	428.71
Illinois	Lakeside	964	7	CS0078	1965	0	1961	C	C	U		3,461.4	148.9	3,288	173.07
Illinois	Lakeside	964	8	CS0078	0	0	1965	C	C	U		3,449.9	148.4	3,277	172.49
Illinois	Marion	976	1	CS0001	1963	0	1963	C	C	U		4,375.9	208.9	4,157	218.79
Illinois	Marion	976	2	CS0001	1963	0	1963	C	C	U		3,413.4	162.9	3,243	170.67
Illinois	Marion	976	3		1963	0	1906	C	C	U		4,250.4	186.9	4,038	212.52
Illinois*	Meredosia	864	4	CS0001	1975	0	0	T	C	U		1,657.2	97.8	1,574	82.86
Illinois*	Meredosia	864	6		0	1975	0	O	O	U		237.3	91.7	225	11.87
Illinois	Newton	6017	1		1977	1977	1977	T	C	U		9,935.3	4,712.0	9,439	496.76
Illinois	Powerton	879	51	CS0506	0	1972	1972	C	C	U		10,303.9	2,751.5	9,789	515.20
Illinois	Powerton	879	52	CS0506	0	1972	1972	C	C	U		9,926.4	2,650.7	9,430	496.32
Illinois	Powerton	879	61	CS0506	0	1975	1975	C	C	U		8,288.9	2,213.4	7,874	414.44
Illinois	Powerton	879	62	CS0506	0	1975	1975	C	C	U		7,549.8	2,016.1	7,172	377.49
Illinois	Waukegan	883	8		1962	1962	1962	T	C	U		7,217.6	1,751.1	6,857	360.88
Illinois	Will County	884	4		1963	1963	1963	T	C	U		5,456.1	1,639.7	5,183	272.81
Illinois	Wood River	898	5		1964	1964	1964	T	C	U		11,319.4	2,135.0	10,753	565.97
Illinois Total:												**516,928.6**		**479,929.2**	**36,999.4**
Indiana	Bailly	995	7	XS12	1962	1962	1962	C	C	WLS	90.0	1,410.2	1,447.7	15	1,395.32
Indiana	Bailly	995	8	XS12	1968	1968	1968	C	C	WLS	90.0	2,403.2	2,467.0	25	2,377.82

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Indiana	Cayuga	1001	1		1970	1970	1970	T	C	U	95.0	38,153.2	3,400.0	0	38,153.20
Indiana	Cayuga	1001	2		1972	1972	1972	T	C	U	95.0	45,309.0	3,757.6	0	45,309.00
Indiana	Dean H Mitchell	996	11	CS611	1970	1970	1970	DB	C	U		2,479.9	715.5	2,356	123.99
Indiana	Elmer W Stout	990	70		0	1973	1973	T	C	U		28,801.2	3,100.9	27,361	1,440.06
Indiana	F B Culley	1012	2	XS23	1966	1966	1966	DB	C	WLS	95.0	2,240.7	882.8	0	2,240.67
Indiana	F B Culley	1012	3	XS23	1973	1973	1973	DB	C	WLS	95.0	6,393.7	2,519.0	0	6,393.73
Indiana	Frank E Ratts	1043	1SG1		0	1970	1970	DB	C	U		6,136.3	639.1	5,829	306.81
Indiana	Frank E Ratts	1043	2SG1		0	1970	1970	DB	C	U		11,043.9	1,110.3	10,492	552.20
Indiana	Gibson	6113	1	CS0003	1976	1976	1975	DB	C	U		43,839.4	5,372.1	41,647	2,191.97
Indiana	Gibson	6113	2	CS0003	1975	1975	1975	DB	C	U		40,442.2	4,955.8	38,420	2,022.11
Indiana	Gibson	6113	3	XS34	1978	1977	1978	DB	C	U		46,208.3	4,716.0	43,898	2,310.42
Indiana	Michigan City	997	12		1974	1974	1974	C	C	U		10,511.8	2,787.3	9,986	525.59
Indiana	Petersburg	994	1		0	1967	1967	T	C	WLS	95.0	2,201.9	1,699.4	0	2,201.90
Indiana	Petersburg	994	2		0	1969	1969	T	C	WLS	95.0	4,945.0	3,611.9	0	4,945.00
Indiana	Petersburg	994	3		0	1977	1977	T	C	WLS	85.0	21,034.2	4,414.5	235	20,799.11
Indiana	R M Schahfer	6085	14		1976	1976	1976	C	C	U		13,718.8	3,367.4	13,033	685.94
Indiana	State Line	981	4		0	1962	1962	C	C	U		3,915.9	1,693.4	3,720	195.79
Indiana	Tanners Creek	988	U4		0	1964	1964	C	C	U		34,707.9	3,675.1	32,973	1,735.39
Indiana	Wabash River	1010	6	CS0005	1968	1968	1968	T	C	U		28,086.9	2,080.1	26,683	1,404.34
Indiana	Warrick	6705	2	XS123	0	0	1964	DB	C	U		29,220.3	1,538.6	27,759	1,461.01
Indiana	Warrick	6705	3	XS123	0	0	1965	DB	C	U		29,025.7	1,528.4	27,574	1,451.28
Indiana	Warrick	6705	4		1970	1970	1970	CB	C	U		36,413.1	2,511.6	34,592	1,820.66
Indiana	Whitewater Valley	1040	2	CS12	1973	1973	0	T	C	U		12,690.5	617.1	12,056	634.52
Indiana Total:												**501,333.1**		**358,655.2**	**142,677.9**
Iowa*	Ames	1122	7		0	0	1968	T	C	U		163.4	98.3	155	8.17
Iowa	Burlington	1104	1		1968	0	1968	T	C	U		6,501.6	1,521.3	6,177	325.08
Iowa	Fair Station	1218	2		1967	0	0	DB	C	U		6,432.8	316.7	6,111	321.64
Iowa	George Neal North	1091	1		1964	0	1964	C	C/G	U		3,420.3	1,037.6	3,249	171.02
Iowa	George Neal North	1091	2		1972	0	1972	DB	C	U		7,326.2	2,307.7	6,960	366.31
Iowa	George Neal North	1091	3		1975	0	1975	DB	C	U		12,418.6	4,179.2	11,798	620.93
Iowa	Lansing	1047	4		1977	0	1977	DTF	C	U		6,881.9	2,117.5	6,538	344.09
Iowa	Milton L Kapp	1048	2		1967	0	1967	T	C	U		4,437.0	1,255.9	4,215	221.85
Iowa	Muscatine	1167	8		1969	0	1969	C	C	U		2,331.1	330.8	2,215	116.56
Iowa	Pella	1175	6	CS67	1972	0	0	S	C	U		289.1	93.4	275	14.46
Iowa	Prairie Creek	1073	4		1967	0	1967	DB	C	U		3,773.3	1,153.8	3,585	188.67
Iowa	Streeter Station	1131	7		1973	0	0	DB	C	U		1,120.1	61.5	1,064	56.00
Iowa Total:												**55,095.4**		**52,340.6**	**2,754.8**
Kentucky	Big Sandy	1353	BSU1	CS012	0	1962	1963	DB	C	U		18,165.0	2,329.9	17,257	908.25
Kentucky	Big Sandy	1353	BSU2	CS012	0	1969	1969	DB	C	U		49,202.6	6,310.9	46,742	2,460.13
Kentucky	Cane Run	1363	4		1962	1962	1962	WBF	C/G	WL	85.0	5,976.6	1,326.9	67	5,909.80
Kentucky	Cane Run	1363	5		1966	1966	1966	WBF	C/G	WL	85.0	6,411.5	1,425.0	72	6,339.84
Kentucky	Cane Run	1363	6		1969	1969	1969	T	C/G	WL	90.0	5,489.2	1,399.4	58	5,431.26
Kentucky	Coleman	1381	C1		0	1969	1969	DB	C	U		11,138.4	1,079.3	10,581	556.92

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Kentucky	Coleman	1381	C2		0	1970	1970	DB	C	U		12,878.8	1,256.4	12,235	643.94
Kentucky	Coleman	1381	C3		0	1971	1971	DB	C	U		13,420.2	1,293.7	12,749	671.01
Kentucky	Cooper	1384	1	CS1	1965	1964	1965	DB	C	U		6,625.2	775.1	6,294	331.26
Kentucky	Cooper	1384	2	CS1	1969	1969	1969	DB	C	U		13,256.4	1,551.0	12,594	662.82
Kentucky	E W Brown	1355	2	CS003	1963	1963	1963	T	C	U		10,745.6	1,104.2	10,208	537.28
Kentucky	E W Brown	1355	3	CS003	1971	1971	1971	T	C	U		27,767.0	2,853.4	26,379	1,388.35
Kentucky	Elmer Smith	1374	1	XS12	1964	1964	1964	C	C	WLS	96.0	2,843.1	1,262.0	0	2,843.10
Kentucky	Elmer Smith	1374	2	XS12	1974	1973	1974	T	C	WLS	96.0	5,559.3	2,467.7	0	5,559.30
Kentucky	Ghent	1356	1	CS001	1974	1974	1973	T	C	WLS	95.0	6,452.0	4,447.2	0	6,452.00
Kentucky	Ghent	1356	2	CS001	1977	1976	1977	T	C	U		20,119.7	4,221.8	19,114	1,005.98
Kentucky	H L Spurlock	6041	1		1977	1977	1977	DB	C	U		16,444.3	2,612.1	15,622	822.22
Kentucky	Henderson I	1372	6		1968	1968	0	S	C	U		996.3	49.5	946	49.81
Kentucky	HMP&L Station	1382	H1		0	1973	1973	DB	C	WL	95.0	2,559.5	1,324.8	0	2,559.50
Kentucky	HMP&L Station	1382	H2		0	1974	1974	DB	C	WL	95.0	3,245.9	1,552.9	0	3,245.90
Kentucky	Mill Creek	1364	1		1972	1972	1972	T	C/G	WLS	90.0	12,103.6	2,642.3	128	11,975.84
Kentucky	Mill Creek	1364	2		1974	1974	1974	T	C/G	WLS	90.0	12,048.2	2,673.7	127	11,921.02
Kentucky	Paradise	1378	1		1963	1963	1963	C	C	WLS	84.2	19,974.1	5,147.3	225	19,748.74
Kentucky	Paradise	1378	2		1963	1963	1963	C	C	WLS	84.2	15,367.3	4,113.6	173	15,193.92
Kentucky	Paradise	1378	3		1970	1969	1970	C	C	U		145,723.6	7,501.1	138,437	7,286.18
Kentucky	Robert Reid	1383	R1		0	1965	0	DB	C	U		7,913.0	418.1	7,517	395.65
Kentucky Total:												**452,426.4**		**337,526.4**	**114,900.0**
Maine	William F Wyman	1507	3		1965	0	1965	T	O	U		6,406.2	738.3	6,086	320.31
Maine Total:												**6,406.2**		**6,085.9**	**320.3**
Maryland	C P Crane	1552	2		1963	1962	1963	C	C	U		18,120.9	1,728.3	17,215	906.05
Maryland	Chalk Point	1571	1	CSE12	0	1964	1964	DB	C	U		22,986.7	2,863.4	21,837	1,149.33
Maryland	Chalk Point	1571	2	CSE12	0	1965	1965	DB	C	U		22,463.4	2,798.2	21,340	1,123.17
Maryland	Chalk Point	1571	3		1975	1975	1975	T	O	U		7,898.4	2,176.6	7,503	394.92
Maryland	Dickerson	1572	3	XS123	1962	1962	1962	T	C	U		9,309.9	1,165.3	8,844	465.50
Maryland	Herbert A Wagner	1554	3		1966	1966	1966	DB	C	U		11,188.5	1,910.8	10,629	559.43
Maryland	Herbert A Wagner	1554	4		1972	1972	1972	DB	O	U		5,666.2	1,300.2	5,383	283.31
Maryland	Morgantown	1573	1		0	1970	1970	T	C	U		41,194.3	4,330.9	39,135	2,059.72
Maryland	Morgantown	1573	2		0	1971	1971	T	C	U		34,325.2	3,704.6	32,609	1,716.26
Maryland	Vienna	1564	8		1971	1971	1971	T	O	U		4,528.2	553.2	4,302	226.41
Maryland Total:												**177,681.7**		**168,797.6**	**8,884.1**
Massachusetts	Brayton Point	1619	1		0	1963	1963	T	C	U		10,328.3	2,129.4	9,812	516.41
Massachusetts	Brayton Point	1619	2		0	1964	1964	T	C	U		10,030.4	2,046.9	9,529	501.52
Massachusetts	Brayton Point	1619	3		0	1969	1969	CB	C	U		23,540.9	4,747.9	22,364	1,177.05
Massachusetts	Brayton Point	1619	4		0	1974	1974	DB	O	U		5,009.6	1,171.3	4,759	250.48
Massachusetts	Canal	1599	1		0	1968	1968	DB	O	U		16,522.8	4,327.8	15,697	826.14
Massachusetts	Canal	1599	2		0	1976	1976	DB	O	U		11,355.6	2,963.2	10,788	567.78
Massachusetts*	Cleary Flood	1682	8		1966	1966	1966	DB	O	U		58.8	17.4	56	2.94
Massachusetts*	Cleary Flood	1682	9		0	1975	1975	O	O	U		188.0	210.5	179	9.40
Massachusetts	Mystic	1588	7		0	1975	1975	T	O	U		10,025.9	2,584.1	9,525	501.30

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Massachusetts	New Boston	1589	1		0	1965	1965	DB	PNG	U		12.6	904.0	12	0.63
Massachusetts	New Boston	1589	2		0	1967	1967	DB	PNG	U		1.8	696.4	2	0.09
Massachusetts	Salem Harbor	1626	4		0	1972	1972	DB	O	U		10,792.0	2,038.7	10,252	539.60
Massachusetts Total:												**97,866.7**		**92,973.4**	**4,893.3**
Michigan	Dan E Karn	1702	3	CS0009	1975	1974	1974	DB	O	U		3,093.0	1,055.7	2,938	154.65
Michigan	Dan E Karn	1702	4	CS0009	1977	1977	1977	DB	O	U		3,273.3	1,117.2	3,110	163.67
Michigan	Eckert Station	1831	4		1964	1964	1964	DB	C	U		1,208.4	469.5	1,148	60.42
Michigan	Eckert Station	1831	5		1968	1968	1968	DB	C	U		1,315.3	492.8	1,250	65.77
Michigan	Eckert Station	1831	6		1970	1970	1970	DB	C	U		1,554.2	536.7	1,476	77.71
Michigan	Erickson	1832	1		1973	1972	1973	DB	C	U		6,744.3	1,201.5	6,407	337.21
Michigan	Harbor Beach	1731	1		1968	1968	1968	DB	C	U		1,654.2	283.3	1,571	82.71
Michigan	J H Campbell	1710	1	CS0009	1962	1962	1962	T	C	U		10,319.3	2,049.0	9,803	515.96
Michigan	J H Campbell	1710	2	CS0009	1967	1967	1967	CB	C	U		13,769.5	2,734.1	13,081	688.48
Michigan	James De Young	1830	5		1969	1969	0	WBF	C	U		1,093.1	204.0	1,038	54.65
Michigan	Monroe	1733	1	CS0012	1971	1971	1971	CB	C	U		29,200.5	5,324.5	27,740	1,460.03
Michigan	Monroe	1733	2	CS0012	1973	1972	1973	CB	C	U		21,010.0	3,831.0	19,960	1,050.50
Michigan	Monroe	1733	3	CS0034	1973	1973	1973	CB	C	U		29,105.2	5,427.5	27,650	1,455.26
Michigan	Monroe	1733	4	CS0034	1974	1974	1974	CB	C	U		32,241.2	6,012.3	30,629	1,612.06
Michigan	Presque Isle	1769	2	CS4	1962	0	1962	T	C	U		406.5	68.9	386	20.32
Michigan	Presque Isle	1769	3	CS4	1964	1963	1964	T	C	U		2,188.2	371.0	2,079	109.41
Michigan	Presque Isle	1769	4	CS4	1966	1966	1966	T	C	U		2,128.6	360.9	2,022	106.43
Michigan	Presque Isle	1769	5		1974	1974	1974	DB	C	U		3,850.2	657.8	3,658	192.51
Michigan	Presque Isle	1769	6		1975	1975	1975	DB	C	U		3,838.3	647.3	3,646	191.92
Michigan	St Clair	1743	7		1969	1969	1969	T	C	U		15,688.6	2,880.5	14,904	784.43
Michigan	Trenton Channel	1745	9A		0	1967	1968	T	C	U		21,102.4	3,655.8	20,047	1,055.12
Michigan Total:												**204,784.2**		**194,545.0**	**10,239.2**
Minnesota	Allen S King	1915	1		0	0	1968	C	C/O	U		27,244.8	3,856.1	25,883	1,362.24
Minnesota	Clay Boswell	1893	3	CS0003	1973	0	1973	T	C	U	25.4	10,528.2	2,792.3	394	10,134.46
Minnesota*	Fox Lake	1888	3		1962	0	1962	DB	C	U		6.0	115.2	6	0.30
Minnesota	Hoot Lake	1943	3		1964	0	1964	DB	C	U		1,286.8	493.2	1,222	64.34
Minnesota	Riverside	1927	8		1964	0	1964	DB	C/O	U		12,639.9	2,045.1	12,008	632.00
Minnesota	Sherburne County	6090	1	CS1	1976	0	1976	T	C/O	WLS	50.0	4,886.6	5,091.0	93	4,793.74
Minnesota	Sherburne County	6090	2	CS1	1977	0	1977	T	C/O	WLS	50.0	5,869.1	6,114.6	112	5,757.60
Minnesota	Silver Lake	2008	4		1969	0	0	DB	C	U		1,545.1	209.5	1,468	77.25
Minnesota Total:												**64,006.5**		**41,184.6**	**22,821.9**
Mississippi	Baxter Wilson	2050	1		1967	0	1966	T	G	U		3,167.1	2,777.0	3,009	158.36
Mississippi	Baxter Wilson	2050	2		1971	0	1971	T	O	U		15,423.7	2,621.0	14,653	771.19
Mississippi	Gerald Andrus	8054	1		1975	0	1975	O	O	U		26,403.6	2,872.0	25,083	1,320.18
Mississippi	Jack Watson	2049	3		1962	0	1962	T	G	U		1.0	361.7	1	0.05
Mississippi	Jack Watson	2049	4		1968	0	1968	DB	C	U		14,037.5	1,881.7	13,336	701.88
Mississippi	Jack Watson	2049	5		1973	0	1973	DB	C	U		32,551.7	4,187.2	30,924	1,627.58
Mississippi	Moselle	2070	1		1970	0	1970	DB	G	U		1.2	263.0	1	0.06
Mississippi	Moselle	2070	2		1970	0	1970	DB	G	U		4.5	404.4	4	0.23

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Mississippi	Moselle	2070	3		1970	0	1970	DB	G	U		8.8	339.4	8	0.44
Mississippi	Victor J Daniel Jr	6073	1		1977	0	1977	T	C	U		13,378.7	3,976.4	12,710	668.94
Mississippi Total:												**104,977.8**		**99,728.9**	**5,248.9**
Missouri	Asbury	2076	1		1970	1970	1970	C	C	U		8,045.6	1,502.8	7,643	402.28
Missouri*	Blue Valley	2132	3		1965	1965	1965	T	C	U		5,300.7	198.2	5,036	265.04
Missouri	Columbia	2123	6	CS5	1963	0	0	S	C	U		422.9	61.0	402	21.14
Missouri	Columbia	2123	7	CS5	1965	1957	0	S	C	U		299.7	43.2	285	14.99
Missouri	Columbia	2123	8		1970	0	0	DB	G	U		0.0	4.1	0	0.00
Missouri	Hawthorn	2079	5		1969	1969	1969	T	C	U		821.4	299.6	780	41.07
Missouri	James River	2161	4		1964	1964	1964	DB	C	U		1,438.2	513.9	1,366	71.91
Missouri	James River	2161	5		1970	1970	1970	DB	C	U		2,587.6	919.8	2,458	129.38
Missouri	Labadie	2103	1		1970	1970	1970	T	C	U		10,183.6	4,548.0	9,674	509.18
Missouri	Labadie	2103	2		1971	1971	1971	T	C	U		10,958.5	5,116.2	10,411	547.93
Missouri	Labadie	2103	3		1972	1972	1972	T	C	U		9,033.3	4,045.7	8,582	451.66
Missouri	Labadie	2103	4		1973	1973	1973	T	C	U		8,605.4	3,656.0	8,175	430.27
Missouri	Lake Road	2098	6		1989	1966	1967	C	C	U		2,088.3	744.7	1,984	104.42
Missouri	Montrose	2080	3	CS023	1964	1964	1964	T	C	U		3,352.0	1,324.5	3,184	167.60
Missouri	New Madrid	2167	1		0	1972	1972	C	C	U		9,569.9	5,154.2	9,091	478.50
Missouri	New Madrid	2167	2		0	1977	1977	C	C	U		6,863.4	3,951.0	6,520	343.17
Missouri	Rush Island	6155	1		1976	1976	1976	T	C	U		12,653.0	4,110.8	12,020	632.65
Missouri	Rush Island	6155	2		1977	1977	1977	T	C	U		14,542.5	4,814.5	13,815	727.13
Missouri	Sibley	2094	2	CS0001	1962	1962	1962	C	C	U		2,538.5	363.1	2,412	126.93
Missouri	Sibley	2094	3	CS0001	1969	1969	1969	C	C	U		20,940.6	2,994.9	19,894	1,047.03
Missouri	Sioux	2107	1		1967	1967	1967	C	C	U		25,148.4	3,306.0	23,891	1,257.42
Missouri	Sioux	2107	2		1968	1968	1968	C	C	U		18,624.1	2,632.8	17,693	931.20
Missouri	Southwest	6195	1		0	1976	1976	DB	C	WLS	87.0	3,538.0	1,783.5	39	3,499.37
Missouri	Thomas Hill	2168	MB1		0	1966	1966	C	C	U		3,139.4	1,663.9	2,982	156.97
Missouri	Thomas Hill	2168	MB2		0	1969	1969	C	C	U		5,219.5	2,859.2	4,959	260.98
Missouri Total:												**185,914.5**		**173,296.3**	**12,618.2**
New Hampshire	Merrimack	2364	2		1968	0	1968	C	C	U		22,319.7	2,356.1	21,204	1,115.98
New Hampshire	Newington	8002	1		1974	0	1974	T	O	U		15,514.8	2,210.2	14,739	775.74
New Hampshire Total:												**37,834.5**		**35,942.8**	**1,891.7**
New Jersey	B L England	2378	1		1962	1962	1962	C	C	U		14,323.3	848.2	13,607	716.16
New Jersey	B L England	2378	2		1964	1964	1964	C	C	WLS	93.0	978.3	922.0	10	968.31
New Jersey	B L England	2378	3		1974	0	1974	DB	O	U		1,232.5	314.1	1,171	61.63
New Jersey	Gilbert	2393	4		1974	1977	0	CC	DSL	U		0.9	118.5	1	0.05
New Jersey	Gilbert	2393	5		1974	1977	0	CC	DSL	U		1.3	121.9	1	0.07
New Jersey	Gilbert	2393	6		1974	1977	0	CC	DSL	U		0.7	104.8	1	0.04
New Jersey	Gilbert	2393	7		1974	1977	0	CC	DSL	U		0.7	110.2	1	0.04
New Jersey	Hudson	2403	1		1964	1964	1964	C	PNG	U		10.6	310.5	10	0.53
New Jersey	Hudson	2403	2		1968	1968	1967	DB	C	U		17,249.6	3,382.5	16,387	862.48
New Jersey Total:												**33,797.9**		**31,188.6**	**2,609.3**
New York	Arthur Kill	2490	30	CS0002	0	1969	1969	T	O	U		5.2	1,983.0	5	0.26

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
New York	Astoria	8906	50		0	1962	1962	T	O	U		651.1	2,629.6	619	32.55
New York	Bowline Point	2625	1		1972	1972	1972	T	O	U		664.1	2,269.4	631	33.20
New York	Bowline Point	2625	2		1974	1974	1974	DB	O	U		1,124.5	1,969.1	1,068	56.23
New York	Charles Poletti	2491	1		0	1976	0	DB	O	U		1,311.1	2,419.2	1,246	65.55
New York	Danskammer	2480	4		1967	1967	1987	T	C	U		7,249.2	1,688.8	6,887	362.46
New York	E F Barrett	2511	10		1971	1956	1956	T	G	U		89.7	1,076.3	85	4.48
New York	E F Barrett	2511	20		0	1963	1963	T	G	U		95.5	986.9	91	4.78
New York	Lovett	2629	4		1966	1966	1966	DB	C	U		4,357.5	1,313.6	4,140	217.88
New York	Lovett	2629	5		1969	1969	1969	DB	C	U		3,922.3	1,223.3	3,726	196.12
New York	Northport	2516	1		0	1967	1967	T	O	U		5,227.8	2,491.0	4,966	261.39
New York	Northport	2516	2		1968	1968	1968	T	O	U		5,003.0	2,457.6	4,753	250.15
New York	Northport	2516	3		1972	1972	1972	T	O	U		7,000.6	1,483.9	6,651	350.03
New York	Northport	2516	4		1977	1977	1977	T	O	U		1,312.5	2,239.0	1,247	65.63
New York	Oswego	2594	5		0	0	1976	DB	O	U		5,038.1	891.9	4,786	251.91
New York	Ravenswood	2500	10		0	1962	1963	T	O	U		13.6	584.9	13	0.68
New York	Ravenswood	2500	20		0	1963	1963	T	O	U		197.4	1,578.8	188	9.87
New York	Ravenswood	2500	30		0	1965	1965	T	O	U		963.6	3,887.0	915	48.18
New York	Roseton	8006	1		1974	1974	1974	T	O	U		11,254.7	2,628.8	10,692	562.74
New York	Roseton	8006	2		1974	1974	1974	T	O	U		13,934.9	3,069.8	13,238	696.75
New York Total:												**69,416.4**		**65,945.6**	**3,470.8**
North Carolina	Asheville	2706	1		1964	1964	1964	DB	C	U		10,564.6	1,464.6	10,036	528.23
North Carolina	Asheville	2706	2		1971	1971	1971	DB	C	U		11,522.8	1,631.5	10,947	576.14
North Carolina	Belews Creek	8042	1		1974	1974	1974	CB	C	U		44,432.1	8,573.3	42,210	2,221.61
North Carolina	Belews Creek	8042	2		1975	1975	1975	CB	C	U		39,417.9	7,497.6	37,447	1,970.89
North Carolina	Buck	2720	7		1970	0	1942	T	C	U		820.4	137.8	779	41.02
North Carolina	Buck	2720	8		1970	1953	1953	T	C	U		4,713.2	827.6	4,478	235.66
North Carolina	Buck	2720	9		1970	1953	1953	T	C	U		4,918.8	881.2	4,673	245.94
North Carolina	Cliffside	2721	5		1972	1972	1972	T	C	U		20,987.9	3,497.9	19,939	1,049.40
North Carolina	L V Sutton	2713	3		1972	1972	1972	DB	C	U		14,368.6	2,320.2	13,650	718.43
North Carolina	Lee	2709	3		1962	1962	1962	DB	C	U		10,099.9	1,483.3	9,595	505.00
North Carolina	Marshall	2727	1		1965	1965	1965	T	C	U		13,738.8	2,560.6	13,052	686.94
North Carolina	Marshall	2727	2		1966	1966	1966	T	C	U		15,126.2	2,799.3	14,370	756.31
North Carolina	Marshall	2727	3		1969	1969	1969	T	C	U		19,370.6	3,512.3	18,402	968.53
North Carolina	Marshall	2727	4		1970	1970	1970	T	C	U		26,303.2	4,698.2	24,988	1,315.16
North Carolina	Riverbend	2732	10		1969	1954	1954	T	C	U		4,686.9	755.6	4,453	234.34
North Carolina	Riverbend	2732	8		1969	1952	1952	T	C	U		1,566.4	254.0	1,488	78.32
North Carolina	Riverbend	2732	9		1969	1954	1954	T	C	U		4,413.9	716.0	4,193	220.69
North Carolina	Roxboro	2712	1		1966	1966	1966	DB	C	U		18,582.3	2,631.5	17,653	929.12
North Carolina	Roxboro	2712	2		1968	1968	1968	T	C	U		31,334.6	4,901.3	29,768	1,566.73
North Carolina	Roxboro	2712	3A	CS0003	0	1973	1973	DB	C	U		17,928.6	2,730.0	17,032	896.43
North Carolina	Roxboro	2712	3B	CS0003	0	1973	1973	DB	C	U		18,271.1	2,782.2	17,358	913.55
North Carolina Total:												**333,168.8**		**316,510.4**	**16,658.4**
Ohio*	Ashtabula	2835	10	CS1	0	1972	1948	DB	C	U		1,594.0	58.5	1,514	79.70

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Ohio*	Ashtabula	2835	11	CS1	0	1972	1948	DB	C	U		1,400.7	51.4	1,331	70.03
Ohio*	Ashtabula	2835	8	CS1	1953	1972	1948	DB	C	U		870.5	32.0	827	43.53
Ohio*	Ashtabula	2835	9	CS1	1953	1972	0	DB	C	U		0.0	0.0	0	0.00
Ohio	Avon Lake	2836	10		1973	1949	1949	T	C	U		1,714.2	352.0	1,628	85.71
Ohio	Avon Lake	2836	12		0	1970	1970	CB	C	U		31,153.8	4,127.9	29,596	1,557.69
Ohio	Avon Lake	2836	9		1970	1949	0	na	na	na		0.0	0.0	0	0.00
Ohio	Bay Shore	2878	3	XS14	1963	1963	1963	DB	C	U		2,048.6	870.1	1,946	102.43
Ohio	Bay Shore	2878	4	XS14	1968	1968	1968	DB	C	U		2,881.8	1,224.0	2,738	144.09
Ohio	Cardinal	2828	1		1967	1966	1966	CB	C	U		60,413.3	3,179.6	57,393	3,020.67
Ohio	Cardinal	2828	2		1967	1967	1967	CB	C	U		34,358.2	3,320.0	32,640	1,717.91
Ohio	Cardinal	2828	3		1977	1977	1977	DB	C	U		20,229.4	3,841.5	19,218	1,011.47
Ohio	Conesville	2840	3		1962	1962	1962	DB	C	U		11,548.1	564.0	10,971	577.40
Ohio	Conesville	2840	4		1973	1973	1973	T	C	U		83,894.0	4,349.1	79,699	4,194.70
Ohio	Conesville	2840	5	CS056	1976	1976	1976	T	C	WL	89.7	11,189.1	2,297.3	119	11,070.58
Ohio	Eastlake	2837	5		1972	1972	1972	CB	C	U		60,128.7	3,316.4	57,122	3,006.43
Ohio	Gen J M Gavin	8102	1		1974	1974	1974	CB	C	WL	95.0	8,717.2	10,178.9	0	8,717.20
Ohio	Gen J M Gavin	8102	2		1975	1975	1975	CB	C	WL	95.0	6,528.8	7,533.2	0	6,528.80
Ohio	Hamilton	2917	9		0	1975	1974	T	C	U	90.0	1,304.0	351.6	14	1,290.24
Ohio	J M Stuart	2850	1		1971	1971	1971	CB	C	U		24,209.9	3,874.6	22,999	1,210.50
Ohio	J M Stuart	2850	2		1970	1970	1970	CB	C	U		23,091.0	3,685.2	21,936	1,154.55
Ohio	J M Stuart	2850	3		1972	1972	1972	CB	C	U		25,128.9	3,993.2	23,872	1,256.45
Ohio	J M Stuart	2850	4		1974	1974	1974	CB	C	U		29,556.7	4,838.1	28,079	1,477.83
Ohio	Lake Road	2908	6		0	0	1967	na	na	na		0.0	0.0	0	0.00
Ohio	Lake Shore	2838	18		1962	0	1962	T	C	U		1,526.5	360.6	1,450	76.33
Ohio	Miami Fort	2832	7		1975	1975	1975	CB	C	U		40,558.8	4,604.5	38,531	2,027.94
Ohio	Miami Fort	2832	8		1978	1977	1978	DB	C	U		19,328.8	4,236.1	18,362	966.44
Ohio	Muskingum River	2872	5		1968	1968	1968	CB	C	U		22,096.2	4,083.9	20,991	1,104.81
Ohio	W H Sammis	2866	4	CS0002	1962	1962	1962	DB	C	U		13,764.4	1,587.1	13,076	688.22
Ohio	W H Sammis	2866	5		1967	1967	1967	DB	C	U		19,110.6	1,998.8	18,155	955.53
Ohio	W H Sammis	2866	6		1969	1969	1969	DB	C	U		36,395.3	5,233.9	34,576	1,819.77
Ohio	W H Sammis	2866	7		1971	1971	1971	CB	C	U		44,027.2	4,307.0	41,826	2,201.36
Ohio	Walter C Beckjord	2830	5		1962	1962	1962	T	C	U		14,763.8	1,891.0	14,026	738.19
Ohio	Walter C Beckjord	2830	6		1969	1969	1969	T	C	U		26,049.5	3,375.7	24,747	1,302.48
Ohio Total:												**679,582.0**		**619,383.0**	**60,199.0**
Pennsylvania	Bruce Mansfield	6094	1		1976	1975	1976	DB	C	WL	92.1	7,490.9	4,596.6	77	7,413.63
Pennsylvania	Bruce Mansfield	6094	2		1977	1977	1977	DB	C	U	92.1	9,438.2	5,139.0	97	9,340.85
Pennsylvania	Brunner Island	3140	2	CS102	1965	1965	1965	T	C	U		22,569.0	2,036.0	21,441	1,128.45
Pennsylvania	Brunner Island	3140	3		1969	1968	1969	T	C	U		30,751.0	4,474.6	29,213	1,537.55
Pennsylvania	Cheswick	8226	1		1970	1970	1970	T	C	U		41,602.0	3,728.1	39,522	2,080.10
Pennsylvania	Conemaugh	3118	1		1970	1970	1970	T	C	WLS	95.0	4,472.1	7,932.2	0	4,472.10
Pennsylvania	Conemaugh	3118	2		1970	1971	1971	T	C	WLS	95.0	3,420.9	6,382.1	0	3,420.90
Pennsylvania	Eddystone	3161	3	CS034	1974	0	1974	T	O	U		730.7	375.5	694	36.53
Pennsylvania	Eddystone	3161	4	CS034	1976	0	1976	T	O	U		857.0	440.4	814	42.85

Red text highlights those units whose SO_2 or NO_x emissions is below 250 tons and/or whose heat input is below 250 mmBtu/hr (see text for further detail), while green represents those units that did not operate in 1999.

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
Pennsylvania	Hatfield's Ferry	3179	1	XS123	1969	1969	1969	CB	C	U		50,556.7	3,487.6	48,029	2,527.84
Pennsylvania	Hatfield's Ferry	3179	2	XS123	1970	1970	1970	CB	C	U		36,828.4	2,540.6	34,987	1,841.42
Pennsylvania	Hatfield's Ferry	3179	3	XS123	1971	1971	1971	CB	C	U		54,487.2	3,758.8	51,763	2,724.36
Pennsylvania	Homer City	3122	1		1969	1969	1969	DB	C	U		74,271.3	5,251.0	70,558	3,713.56
Pennsylvania	Homer City	3122	2		1969	1969	1969	DB	C	U		66,593.7	4,771.3	63,264	3,329.69
Pennsylvania	Homer City	3122	3		1977	1977	1977	DB	C	U		22,597.2	4,475.0	21,467	1,129.86
Pennsylvania	Keystone	3136	1		1967	1967	1967	T	C	U		75,763.5	6,365.8	71,975	3,788.18
Pennsylvania	Keystone	3136	2		1968	1968	1968	T	C	U		86,526.6	7,346.0	82,200	4,326.33
Pennsylvania	Martins Creek	3148	3		1975	1975	1975	T	O	U		2,248.3	930.2	2,136	112.42
Pennsylvania	Martins Creek	3148	4		1977	1976	1977	T	O	U		3,309.5	1,176.4	3,144	165.48
Pennsylvania	Mitchell	3181	3		1963	0	1949	DVF	DSL	U		8.5	10.9	8	0.43
Pennsylvania	Mitchell	3181	33		0	1963	1963	T	C	WL	95.0	993.9	1,759.9	0	993.90
Pennsylvania	Montour	3149	1		1972	1971	1972	T	C	U		52,151.0	4,289.3	49,543	2,607.55
Pennsylvania	Montour	3149	2		1973	1973	1973	T	C	U		61,635.5	5,048.8	58,554	3,081.78
Pennsylvania	New Castle	3138	5		1964	1964	1964	DB	C	U		8,313.2	707.3	7,898	415.66
Pennsylvania	Portland	3113	2		1962	1962	1962	T	C	U		15,099.4	1,341.4	14,344	754.97
Pennsylvania	Warren	3132	3	CS3	1972	0	0	DB	C	U		1,298.7	106.1	1,234	64.94
Pennsylvania Total:												**734,014.5**		**672,963.2**	**61,051.3**
South Carolina	Canadys Steam	3280	CAN1		0	1962	1962	T	C	U		3,122.0	384.5	2,966	156.10
South Carolina	Canadys Steam	3280	CAN2		0	1964	1964	T	C	U		3,115.2	317.6	2,959	155.76
South Carolina	Canadys Steam	3280	CAN3		0	1967	1967	T	C	U		5,640.0	648.4	5,358	282.00
South Carolina	Dolphus M Grainger	3317	1		1966	1966	1966	DB	C	U		5,427.4	547.3	5,156	271.37
South Carolina	Dolphus M Grainger	3317	2		1966	1966	1966	DB	C	U		5,147.8	508.9	4,890	257.39
South Carolina	Jefferies	3319	3		1970	1969	1970	DB	C	U		9,916.6	1,016.0	9,421	495.83
South Carolina	Jefferies	3319	4		1970	1970	1970	DB	C	U		12,894.2	1,282.4	12,249	644.71
South Carolina	Wateree	3297	WAT1		0	1970	1970	DB	C	U		19,751.2	2,437.8	18,764	987.56
South Carolina	Wateree	3297	WAT2		0	1971	1971	DB	C	U		19,749.9	2,422.5	18,762	987.50
South Carolina	Williams	3298	WIL1		0	1973	1973	T	C	U		24,937.0	5,402.3	23,690	1,246.85
South Carolina	Winyah	6249	1		1975	1974	1975	DB	C	U		20,982.1	2,403.5	19,933	1,049.10
South Carolina	Winyah	6249	2		1977	1977	1977	DTF	C	WLS	45.0	10,485.2	2,119.4	221	10,263.85
South Carolina Total:												**141,168.6**		**124,370.6**	**16,798.0**
Tennessee	Bull Run	3396	1		1967	1967	1967	T	C	U		38,178.5	4,641.4	36,270	1,908.93
Tennessee	Cumberland	3399	1	1	1973	1972	1973	CB	C	WLS	95.0	7,069.8	8,408.3	0	7,069.80
Tennessee	Cumberland	3399	2		1973	1973	1973	CB	C	WLS	95.0	8,851.0	12,078.5	0	8,851.00
Tennessee Total:												**54,099.3**		**36,269.6**	**17,829.7**
Virginia	Chesapeake	3803	4		0	1962	1962	T	C	U		14,447.5	2,005.1	13,725	722.38
Virginia	Chesterfield	3797	5		1964	1964	1964	T	C	U		19,813.2	2,443.0	18,823	990.66
Virginia	Chesterfield	3797	6		1969	1969	1969	T	C	U		28,534.8	3,531.2	27,108	1,426.74
Virginia	Possum Point	3804	4		1962	1962	1962	T	C	U		12,171.3	1,797.4	11,563	608.56
Virginia	Possum Point	3804	5		1975	0	1975	T	O	U		1,993.0	702.0	1,893	99.65
Virginia	Yorktown	3809	3		1974	1974	1974	T	O	U		12,753.1	2,814.6	12,115	637.65
Virginia Total:												**89,712.9**		**85,227.3**	**4,485.6**
West Virginia	Fort Martin	3943	1		1967	1967	1967	T	C	U		50,942.7	4,531.3	48,396	2,547.13

Red text highlights those units whose SO_2 or NO_x emissions is below 250 tons and/or whose heat input is below 250 mmBtu/hr (see text for further detail), while green represents those units that did not operate in 1999.

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	SO2 Controls	SO2 Control Efficiency	1999 SO2 (tons)	1999 Heat Input (mmBtu/hr)	Potential SO2 Reductions (tons)	Estimated SO2 Emissions (tons)
West Virginia	Fort Martin	3943	2		1968	1968	1968	CB	C	U		48,157.9	4,263.2	45,750	2,407.89
West Virginia	Harrison	3944	1	XS123	1972	1972	1972	DB	C	WL	98.0	2,409.7	5,824.5	0	2,409.70
West Virginia	Harrison	3944	2	XS123	1973	1973	1973	DB	C	WL	98.0	2,112.2	5,105.5	0	2,112.20
West Virginia	Harrison	3944	3	XS123	1974	1974	1974	DB	C	WL	98.0	2,313.2	5,591.3	0	2,313.20
West Virginia	John E Amos	3935	1	CS012	1971	1971	1971	DB	C	U		27,868.4	5,069.0	26,475	1,393.42
West Virginia	John E Amos	3935	2	CS012	1972	1972	1972	DB	C	U		33,323.1	6,061.2	31,657	1,666.15
West Virginia	John E Amos	3935	3		1973	1973	1973	CB	C	U		47,523.9	8,916.1	45,148	2,376.19
West Virginia	Mitchell	3948	1	CS012	1971	1971	1971	DB	C	U		26,998.5	4,860.3	25,649	1,349.93
West Virginia	Mitchell	3948	2	CS012	1971	1971	1971	DB	C	U		28,047.4	5,049.2	26,645	1,402.37
West Virginia	Mt Storm	3954	1	CS0	1965	1965	1965	T	C	U		52,640.6	4,542.1	50,009	2,632.03
West Virginia	Mt Storm	3954	2	CS0	1966	1966	1966	T	C	U		48,482.9	4,183.3	46,059	2,424.15
West Virginia	Mt Storm	3954	3		1973	1973	1973	T	C	WLS	90.0	3,480.5	4,500.0	37	3,443.76
West Virginia Total:												**374,301.0**		**345,822.9**	**28,478.1**
Wisconsin	Blount Street	3992	11		0	0	1964	DB	G	U		0.0	6.1	0	0.00
Wisconsin*	Blount Street	3992	3		0	0	1968	O	G	U		0.3	22.7	0	0.02
Wisconsin	Columbia	8023	1		1975	1975	1975	T	C	U		13,811.6	4,376.7	13,121	690.58
Wisconsin	Edgewater	4050	4		1969	1969	1969	C	C	U		6,624.1	2,119.8	6,293	331.21
Wisconsin	Genoa	4143	1		0	1969	1969	T	C	U		12,513.2	2,328.2	11,888	625.66
Wisconsin	Manitowoc	4125	6	CS0020	1964	0	0	S	C	U		746.5	121.6	709	37.33
Wisconsin	Nelson Dewey	4054	2	CS1	1962	1962	1962	C	C	U		6,688.0	809.8	6,354	334.40
Wisconsin	Pulliam	4072	8		1964	1964	1964	DB	C	U		2,195.8	1,186.7	2,086	109.79
Wisconsin	South Oak Creek	4041	7	CS4	1965	1965	1965	T	C	U		8,659.3	2,292.7	8,226	432.97
Wisconsin	South Oak Creek	4041	8	CS4	1967	1967	1967	T	C	U		8,493.5	2,248.8	8,069	424.67
Wisconsin	Valley (WEPCO)	4042	1	CS1	1968	1968	1968	DB	C	U		3,891.9	467.1	3,697	194.60
Wisconsin	Valley (WEPCO)	4042	2	CS1	1969	1968	1968	DB	C	U		3,896.0	467.6	3,701	194.80
Wisconsin	Valley (WEPCO)	4042	3	CS2	1969	1969	1969	DB	C	U		4,055.7	485.8	3,853	202.79
Wisconsin	Valley (WEPCO)	4042	4	CS2	0	1969	1969	DB	C	U		4,134.8	495.3	3,928	206.74
Wisconsin Total:												**75,710.7**		**71,925.2**	**3,785.5**
Total SO_2 Emissions in Source Region												**5,630,789**		**5,009,713**	**621,076**

Red text highlights those units whose SO_2 or NO_x emissions is below 250 tons and/or whose heat input is below 250 mmBtu/hr (see text for further detail), while green represents those units that did not operate in 1999.

Appendix B: NO_X Emissions from BART-Eligible Sources

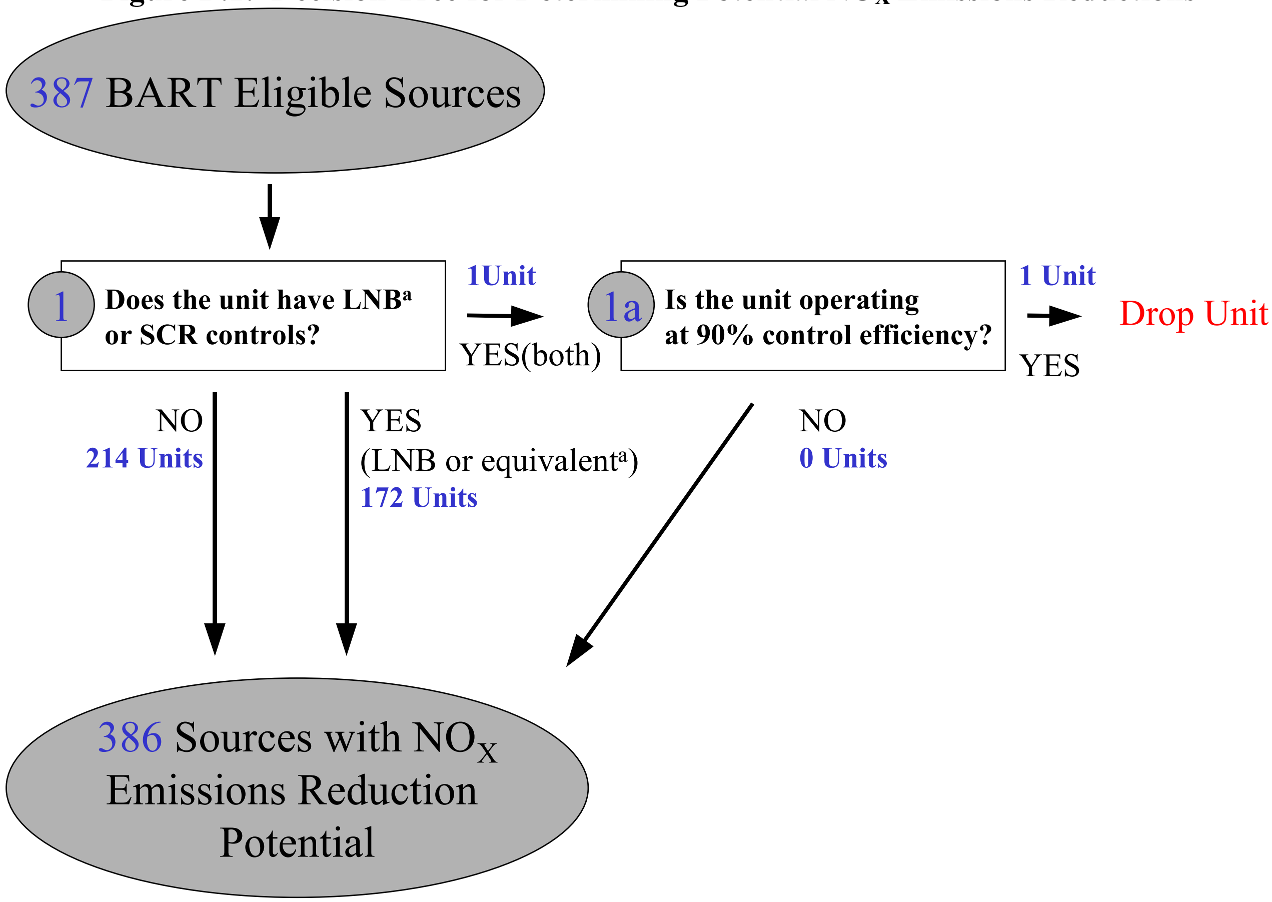
The analysis for potential NO_X reductions follows that for SO_2 reductions closely and relies on the same data sources for relevant information. The same criteria have been applied to determine BART-eligibility with respect to NO_X emissions reductions. In fact, once a source triggers BART-eligibility on the basis of any visibility impairing pollutant,[95] then a BART analysis must be conducted for all visibility impairing pollutants regardless of each particular pollutant's emission level. Hence, the same 387 sources which were determined to be BART-eligible following the decision tree shown in Figure A-1 (see Appendix A) are listed in Table B-1 with their associated NO_X emissions and current controls. Units which were flagged due to insufficient information regarding heat input and potential to emit are shown in the Table B-1 in red. Green text is used to denote units which may be BART-eligible, but did not operate in 1999, the year used for the current analysis.

Differences in the analysis occur when NO_X control technology is considered. Figure B-1 shows the analysis procedure for determining potential NO_X emissions reductions for each of the BART-eligible sources listed in Table B-1. For the purposes of this analysis, we assume that the combination of low NO_X burner (LNB) technology combined with Selective Catalytic Reduction (SCR) was capable of achieving 94 percent NO_X control efficiency. If a source has low NO_X burner or equivalent technology, a control efficiency of 35 percent is assumed and application of SCR as BART is anticipated to achieve an additional 90 percent reduction (94 percent overall control efficiency). Only one of the 387 identified units is equipped with SCR control technology and is already operating at 94 percent control efficiency. We assume that no further emissions reductions can be achieved at this unit.

This analysis resulted in 2 million tons of potential NO_X emissions reductions that could result from the application of BART to BART-eligible power plants in the source region affecting Northeast and Mid-Atlantic Class I areas.

[95] SO_2, NO_X, Ammonia, VOCs, and PM_{10} are included in this category (USEPA, 2001); however, only SO_2 and NO_X emissions were used to determine BART-eligibility in this analysis.

Figure B.1: Decision Tree for Determining Potential NO_X Emissions Reductions



Notes:
[a] Water injection, overfire air, and combustion modification with fuel reburn are all assumed to achieve 35% control efficiency.

Table B-1: NO_X emission information from 387 potentially BART-eligible boilers located in the preliminary geographic source region of influence for Class I areas in the Mid-Atlantic and Northeast U.S.

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Alabama	Barry	3	4		1969	1969	1969	T	C	LNC2	35	5,502.5	3,334.1	4,994.5	508
Alabama	Barry	3	5		1971	1971	1971	T	C	LNC2	35	10,960.0	6,115.0	9,948.3	1,012
Alabama	Charles R Lowan	56	1		1969	1969	1969	DB	C	U		1,347.9	463.4	1,347.9	0
Alabama	Colbert	47	5		1965	1965	1965	DB	C	U		5,342.7	2,983.6	5,342.7	0
Alabama	E C Gaston	26	4	CS0CBN	0	1962	1962	DB	C	LNB	35	4,125.7	1,990.5	3,744.9	381
Alabama	E C Gaston	26	5		1974	1974	1974	T	C	LNB	35	11,254.2	6,288.6	10,215.4	1,039
Alabama	Gorgas	8	10		1972	1972	1972	T	C	LNC2[b]	35	15,241.9	4,761.6	13,835.0	1,407
Alabama	Greene County	10	1		1965	1965	1965	CB	C	U		6,407.1	1,760.9	6,407.1	0
Alabama	Greene County	10	2		1966	1966	1966	DB	C	LNB	35	4,098.6	2,242.9	3,720.3	378
Alabama	Widows Creek	50	8		1965	1964	1965	T	C	U		6,604.1	3,674.5	6,604.1	0
Alabama Total:												**70,884.8**		**66,160.3**	**4,724.6**
Arkansas	Carl Bailey	202	1		1966	0	0	DB	G	U		443.7	315.6	417.1	27
Arkansas	Lake Catherine	170	4		1970	0	1970	DB	G	U		2,378.5	2,073.7	2,235.8	143
Arkansas	Mcclellan	203	1		1972	0	0	DB	G	U		559.2	433.1	525.6	34
Arkansas	Robert E Ritchie	173	2		1968	0	1968	T	G	U		1,078.4	1,146.7	1,013.7	65
Arkansas	Thomas Fitzhugh	201	1		1963	0	0	DB	G	U		432.0	133.3	406.1	26
Arkansas Total:												**4,891.8**		**4,598.3**	**293.5**
Connecticut	Middletown	562	3		1964	0	1964	C	O	$H2O^c$	35	1,198.6	879.4	1,087.9	111
Connecticut	Middletown	562	4		1973	0	1973	T	O	U		1,101.1	1,290.8	1,035.0	66
Connecticut	Montville	546	6		1971	1971	1971	T	O	U		1,042.5	1,157.1	980.0	63
Connecticut	Norwalk Harbor	548	2	CS0001	1963	0	1963	T	O	U		894.4	917.0	840.8	54
Connecticut	WISVEST - Bridgeport Harbo	568	BHB3		0	1968	1968	T	C	LNC2	35	1,538.5	1,983.9	1,396.5	142
Connecticut	WISVEST - New Haven Harb	6156	NHB1		0	1975	1975	T	O	U		2,351.5	2,657.2	2,210.4	141
Connecticut Total:												**8,126.6**		**7,550.6**	**576.0**
Delaware	Edge Moor	593	4		1966	1966	1966	T	C	U		1,242.3	928.8	1,167.8	75
Delaware	Edge Moor	593	5		1973	1973	1973	DB	O	LNB	35	2,546.5	1,719.0	2,311.5	235
Delaware*	Indian River	594	3		1970	1970	1970	DB	C	U[c]		301.8	203.7	283.7	18
Delaware*	Mckee Run	599	3		1975	1975	1975	DB	O	LNB	35	375.4	236.3	340.8	35
Delaware Total:												**4,466.1**		**4,103.7**	**362.4**
District of Columbia	Benning	603	15		1968	0	1968	T	O	U		228.3	195.6	214.6	14
District of Columbia	Benning	603	16		1972	1972	1972	DB	O	U		218.8	181.5	205.7	13
District of Columbia Total:												**447.1**		**420.3**	**26.8**
Georgia	Bowen	703	1BLR		0	1971	1971	T	C	LNB[b]	35	8,545.6	4,625.2	7,756.8	789
Georgia	Bowen	703	2BLR		0	1972	1972	T	C	LNB[b]	35	10,123.5	5,432.4	9,189.1	934
Georgia	Bowen	703	3BLR		0	1974	1974	T	C	LNB[b]	35	10,965.9	5,904.8	9,953.7	1,012
Georgia	Bowen	703	4BLR		0	1975	1975	T	C	LNB[b]	35	12,040.0	6,474.5	10,928.6	1,111
Georgia	Hammond	708	4		1970	1970	1970	DB	C	LNB[b]	35	6,464.0	3,200.5	5,867.3	597
Georgia	Harllee Branch	709	1	CS001	1965	1965	1965	CB	C	U[a]		6,084.7	1,529.7	5,719.6	365

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [C]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Georgia	Harllee Branch	709	2	CS001	1967	1967	1967	DB	C	U[a]		5,146.9	1,540.2	4,838.1	309
Georgia	Harllee Branch	709	3	CS002	1968	1968	1968	CB	C	U[a]		9,751.7	2,617.9	9,166.6	585
Georgia	Harllee Branch	709	4	CS002	1969	1969	1969	CB	C	U[a]		10,343.8	2,776.8	9,723.2	621
Georgia	Jack Mcdonough	710	MB1	CS001	0	1963	1963	T	C	LNB	35	2,547.3	1,784.6	2,312.1	235
Georgia	Jack Mcdonough	710	MB2	CS001	0	1964	1964	T	C	LNB	35	2,425.2	1,699.1	2,201.3	224
Georgia	Kraft	733	3	CS001	1965	1965	1965	T	C/G	U		1,669.8	699.3	1,569.6	100
Georgia	Kraft	733	4	CS001	1972	1972	1972	T	O	U		515.0	215.7	484.1	31
Georgia	Mitchell	727	3		1964	1964	1964	T	C	U		1,288.1	527.6	1,210.8	77
Georgia	Wansley	6052	1		1976	1976	1976	T	C	U[b]		10,537.5	5,916.1	9,905.2	632
Georgia	Yates	728	Y6BR		0	1974	1974	T	C	LNB	35	2,009.4	1,601.6	1,823.9	185
Georgia	Yates	728	Y7BR		0	1974	1974	T	C	LNB	35	2,372.1	1,818.2	2,153.1	219
Georgia Total:												**102,830.3**		**94,803.0**	**8,027.3**
Illinois	Baldwin	889	1		1970	1970	1970	C	C	U[b]		20,329.7	2,952.4	19,109.9	1,220
Illinois	Baldwin	889	2		1973	1973	1973	C	C	U[b]		28,530.0	4,127.3	26,818.2	1,712
Illinois	Baldwin	889	3		1975	1975	1975	T	C	LNC2[b]	35	6,167.0	3,974.8	5,597.7	569
Illinois	Coffeen	861	1	CS0001	1965	1965	0	C	C	U		10,883.3	1,996.5	10,230.3	653
Illinois	Coffeen	861	2	CS0001	1972	1972	0	C	C	U		16,945.4	3,108.6	15,928.7	1,017
Illinois	Collins	6025	2	CS1230	1977	1977	1977	DB	G	LNBO	35	575.8	961.8	522.7	53
Illinois	Collins	6025	3	CS1230	1977	1977	1977	DB	G	LNBO	35	661.4	1,104.8	600.4	61
Illinois	Dallman	963	31		0	1968	1968	C	C	U		2,826.3	627.0	2,656.7	170
Illinois	Dallman	963	32		0	1972	1972	C	C	U		2,494.1	542.5	2,344.5	150
Illinois	Duck Creek	6016	1		1976	1976	1976	DB	C	LNB	35	6,454.7	2,722.3	5,858.9	596
Illinois	E D Edwards	856	2		1968	1968	1968	DB	C	LNB	35	3,523.7	1,625.6	3,198.4	325
Illinois	E D Edwards	856	3		1972	1972	1972	DB	C	LNB	35	5,004.2	2,165.5	4,542.3	462
Illinois	Joilet 29	384	71	CS7172	0	1965	1965	T	C	U		2,399.7	1,377.2	2,255.7	144
Illinois	Joilet 29	384	72	CS7172	0	1965	1965	T	C	U		4,231.0	2,428.2	3,977.2	254
Illinois	Joilet 29	384	81	CS8182	0	1966	1965	T	C	U		2,659.2	1,508.0	2,499.6	160
Illinois	Joilet 29	384	82	CS8182	0	1966	1965	T	C	U		3,687.1	2,090.9	3,465.9	221
Illinois	Kincaid	876	1	CS0102	0	1967	1967	C	C	U		15,411.7	3,582.7	14,487.0	925
Illinois	Kincaid	876	2	CS0102	0	1968	1968	C	C	U		11,702.0	2,720.3	10,999.9	702
Illinois	Lakeside	964	7	CS0078	1965	0	1961	C	C	U		491.0	148.9	461.5	29
Illinois	Lakeside	964	8	CS0078	0	0	1965	C	C	U		490.1	148.4	460.7	29
Illinois	Marion	976	1	CS0001	1963	0	1963	C	C	U		818.7	208.9	769.6	49
Illinois	Marion	976	2	CS0001	1963	0	1963	C	C	U		638.7	162.9	600.3	38
Illinois	Marion	976	3		1963	0	1906	C	C	U		806.4	186.9	758.0	48
Illinois*	Meredosia	864	4	CS0001	1975	0	0	T	C	U		225.1	97.8	211.6	14
Illinois*	Meredosia	864	6		0	1975	0	O	O	O	35	89.5	91.7	81.2	8
Illinois	Newton	6017	1		1977	1977	1977	T	C	LNC3	35	3,383.1	4,712.0	3,070.8	312

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [C]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Illinois	Powerton	879	51	CS0506	0	1972	1972	C	C	U		11,046.2	2,751.5	10,383.4	663
Illinois	Powerton	879	52	CS0506	0	1972	1972	C	C	U		10,641.4	2,650.7	10,003.0	638
Illinois	Powerton	879	61	CS0506	0	1975	1975	C	C	U		8,886.0	2,213.4	8,352.8	533
Illinois	Powerton	879	62	CS0506	0	1975	1975	C	C	U		8,093.7	2,016.1	7,608.1	486
Illinois	Waukegan	883	8		1962	1962	1962	T	C	U		2,621.0	1,751.1	2,463.7	157
Illinois	Will County	884	4		1963	1963	1963	T	C	U		2,042.2	1,639.7	1,919.6	123
Illinois	Wood River	898	5		1964	1964	1964	T	C	U		5,042.5	2,135.0	4,740.0	303
Illinois Total:												**199,801.9**		**186,978.3**	**12,823.6**
Indiana	Bailly	995	7	XS12	1962	1962	1962	C	C	U		9,307.3	1,447.7	8,748.8	558
Indiana	Bailly	995	8	XS12	1968	1968	1968	C	C	U		15,860.9	2,467.0	14,909.3	952
Indiana	Cayuga	1001	1		1970	1970	1970	T	C	LNC2[b]	35	4,643.6	3,400.0	4,215.0	429
Indiana	Cayuga	1001	2		1972	1972	1972	T	C	LNC2[b]	35	5,452.7	3,757.6	4,949.4	503
Indiana	Dean H Mitchell	996	11	CS611	1970	1970	1970	DB	C	U		889.9	715.5	836.5	53
Indiana	Elmer W Stout	990	70		0	1973	1973	T	C	LNC3	35	5,024.8	3,100.9	4,560.9	464
Indiana	F B Culley	1012	2	XS23	1966	1966	1966	DB	C	LNB	35	1,787.9	882.8	1,622.8	165
Indiana	F B Culley	1012	3	XS23	1973	1973	1973	DB	C	LNB	35	5,101.7	2,519.0	4,630.7	471
Indiana	Frank E Ratts	1043	1SG1		0	1970	1970	DB	C	LNB	35	1,368.0	639.1	1,241.7	126
Indiana	Frank E Ratts	1043	2SG1		0	1970	1970	DB	C	LNB	35	2,300.5	1,110.3	2,088.1	212
Indiana	Gibson	6113	1	CS0003	1976	1976	1975	DB	C	LNBO[b]	35	10,670.7	5,372.1	9,685.7	985
Indiana	Gibson	6113	2	CS0003	1975	1975	1975	DB	C	LNBO[b]	35	9,843.8	4,955.8	8,935.1	909
Indiana	Gibson	6113	3	XS34	1978	1977	1978	DB	C	LNBO[b]	35	9,637.2	4,716.0	8,747.6	890
Indiana	Michigan City	997	12		1974	1974	1974	C	C	U		7,221.5	2,787.3	6,788.2	433
Indiana	Petersburg	994	1		0	1967	1967	T	C	LNC3	35	1,994.2	1,699.4	1,810.2	184
Indiana	Petersburg	994	2		0	1969	1969	T	C	LNC3	35	5,301.1	3,611.9	4,811.8	489
Indiana	Petersburg	994	3		0	1977	1977	T	C	LNC1	35	6,519.5	4,414.5	5,917.7	602
Indiana	R M Schahfer	6085	14		1976	1976	1976	C	C	U		15,695.9	3,367.4	14,754.2	942
Indiana	State Line	981	4		0	1962	1962	C	C	U		6,644.8	1,693.4	6,246.1	399
Indiana	Tanners Creek	988	U4		0	1964	1964	C	C	U		23,085.6	3,675.1	21,700.5	1,385
Indiana	Wabash River	1010	6	CS0005	1968	1968	1968	T	C	LNC2	35	3,371.5	2,080.1	3,060.3	311
Indiana	Warrick	6705	2	XS123	0	0	1964	DB	C	U		4,633.5	1,538.6	4,355.5	278
Indiana	Warrick	6705	3	XS123	0	0	1965	DB	C	U		4,602.6	1,528.4	4,326.5	276
Indiana	Warrick	6705	4		1970	1970	1970	CB	C	U		5,191.6	2,511.6	4,880.1	311
Indiana	Whitewater Valley	1040	2	CS12	1973	1973	0	T	C	LNB	35	1,155.4	617.1	1,048.8	107
Indiana Total:												**167,306.1**		**154,871.4**	**12,434.7**
Iowa*	Ames	1122	7		0	0	1968	T	C	U		156.5	98.3	147.1	9
Iowa	Burlington	1104	1		1968	0	1968	T	C	LNB	35	1,399.5	1,521.3	1,270.4	129
Iowa	Fair Station	1218	2		1967	0	0	DB	C	U		779.2	316.7	732.5	47
Iowa	George Neal North	1091	1		1964	0	1964	C	C/G	U		3,905.9	1,037.6	3,671.6	234
Iowa	George Neal North	1091	2		1972	0	1972	DB	C	U		4,407.1	2,307.7	4,142.7	264

The NOx control Technology scheduled to be added to the boiler: [a]LNB, [b]SCR, [c]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Iowa	George Neal North	1091	3		1975	0	1975	DB	C	U		8,803.5	4,179.2	8,275.3	528
Iowa	Lansing	1047	4		1977	0	1977	DTF	C	U		4,050.1	2,117.5	3,807.1	243
Iowa	Milton L Kapp	1048	2		1967	0	1967	T	C	LNC3	35	1,794.9	1,255.9	1,629.2	166
Iowa	Muscatine	1167	8		1969	0	1969	C	C	U		1,236.8	330.8	1,162.6	74
Iowa	Pella	1175	6	CS67	1972	0	0	S	C	U		159.1	93.4	149.5	10
Iowa	Prairie Creek	1073	4		1967	0	1967	DB	C	U		1,937.7	1,153.8	1,821.4	116
Iowa	Streeter Station	1131	7		1973	0	0	DB	C	U		226.9	61.5	213.3	14
Iowa Total:												**28,857.3**		**27,022.6**	**1,834.6**
Kentucky	Big Sandy	1353	BSU1	CS012	0	1962	1963	DB	C	U		5,583.5	2,329.9	5,248.5	335
Kentucky	Big Sandy	1353	BSU2	CS012	0	1969	1969	DB	C	LNB[b]	35	15,123.7	6,310.9	13,727.7	1,396
Kentucky	Cane Run	1363	4		1962	1962	1962	WBF	C/G	U		2,736.9	1,326.9	2,572.7	164
Kentucky	Cane Run	1363	5		1966	1966	1966	WBF	C/G	U		3,179.7	1,425.0	2,988.9	191
Kentucky	Cane Run	1363	6		1969	1969	1969	T	C/G	U		2,258.1	1,399.4	2,122.6	135
Kentucky	Coleman	1381	C1		0	1969	1969	DB	C	LNB	35	2,098.9	1,079.3	1,905.2	194
Kentucky	Coleman	1381	C2		0	1970	1970	DB	C	LNB	35	2,508.7	1,256.4	2,277.2	232
Kentucky	Coleman	1381	C3		0	1971	1971	DB	C	LNB	35	2,549.2	1,293.7	2,313.9	235
Kentucky	Cooper	1384	1	CS1	1965	1964	1965	DB	C	LNB	35	1,451.3	775.1	1,317.3	134
Kentucky	Cooper	1384	2	CS1	1969	1969	1969	DB	C	LNB[b]	35	2,903.9	1,551.0	2,635.8	268
Kentucky	E W Brown	1355	2	CS003	1963	1963	1963	T	C	LNC1	35	1,907.8	1,104.2	1,731.7	176
Kentucky	E W Brown	1355	3	CS003	1971	1971	1971	T	C	LNC3[b]	35	4,929.9	2,853.4	4,474.8	455
Kentucky	Elmer Smith	1374	1	XS12	1964	1964	1964	C	C	U		8,231.4	1,262.0	7,737.5	494
Kentucky	Elmer Smith	1374	2	XS12	1974	1973	1974	T	C	LNC1	35	4,470.6	2,467.7	4,057.9	413
Kentucky	Ghent	1356	1	CS001	1974	1974	1973	T	C	LNC2	35	7,958.7	4,447.2	7,224.1	735
Kentucky	Ghent	1356	2	CS001	1977	1976	1977	T	C	OFA	35	9,128.8	4,221.8	8,286.2	843
Kentucky	H L Spurlock	6041	1		1977	1977	1977	DB	C	LNB[b]	35	4,896.7	2,612.1	4,444.7	452
Kentucky	Henderson I	1372	6		1968	1968	0	S	C	U		96.4	49.5	90.6	6
Kentucky	HMP&L Station	1382	H1		0	1973	1973	DB	C	LNB	35	2,791.7	1,324.8	2,534.0	258
Kentucky	HMP&L Station	1382	H2		0	1974	1974	DB	C	LNB	35	3,282.8	1,552.9	2,979.8	303
Kentucky	Mill Creek	1364	1		1972	1972	1972	T	C/G	U[b]		4,503.4	2,642.3	4,233.2	270
Kentucky	Mill Creek	1364	2		1974	1974	1974	T	C/G	U[b]		3,982.5	2,673.7	3,743.6	239
Kentucky	Paradise	1378	1		1963	1963	1963	C	C	U[b]		17,411.9	5,147.3	16,367.2	1,045
Kentucky	Paradise	1378	2		1963	1963	1963	C	C	U[b]		26,340.2	4,113.6	24,759.8	1,580
Kentucky	Paradise	1378	3		1970	1969	1970	C	C	U		60,604.6	7,501.1	56,968.3	3,636
Kentucky	Robert Reid	1383	R1		0	1965	0	DB	C	U		1,507.4	418.1	1,416.9	90
Kentucky Total:												**202,438.6**		**188,159.8**	**14,278.7**
Maine	William F Wyman	1507	3		1965	0	1965	T	O	U		879.4	738.3	826.7	53
Maine Total:												**879.4**		**826.7**	**52.8**
Maryland	C P Crane	1552	2		1963	1962	1963	C	C	U		8,116.7	1,728.3	7,629.7	487
Maryland	Chalk Point	1571	1	CSE12	0	1964	1964	DB	C	LNB[b]	35	5.8	2,863.4	5.3	1

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Maryland	Chalk Point	1571	2	CSE12	0	1965	1965	DB	C	LNB[b]	35	6.1	2,798.2	5.5	1
Maryland	Chalk Point	1571	3		1975	1975	1975	T	O	U		3,877.0	2,176.6	3,644.4	233
Maryland	Dickerson	1572	3	XS123	1962	1962	1962	T	C	U		3,254.1	1,165.3	3,058.9	195
Maryland	Herbert A Wagner	1554	3		1966	1966	1966	DB	C	U[b]		3,317.7	1,910.8	3,118.7	199
Maryland	Herbert A Wagner	1554	4		1972	1972	1972	DB	O	U		2,562.5	1,300.2	2,408.8	154
Maryland	Morgantown	1573	1		0	1970	1970	T	C	LNC3[b]	35	12,161.2	4,330.9	11,038.6	1,123
Maryland	Morgantown	1573	2		0	1971	1971	T	C	LNC3[b]	35	9,988.3	3,704.6	9,066.3	922
Maryland	Vienna	1564	8		1971	1971	1971	T	O	U		750.0	553.2	705.0	45
Maryland Total:												**44,039.6**		**40,681.2**	**3,358.4**
Massachusetts	Brayton Point	1619	1		0	1963	1963	T	C	LNC3[b]	35	2,677.1	2,129.4	2,430.0	247
Massachusetts	Brayton Point	1619	2		0	1964	1964	T	C	LNC3[b]	35	2,578.0	2,046.9	2,340.0	238
Massachusetts	Brayton Point	1619	3		0	1969	1969	CB	C	LNBO[b]	35	8,089.0	4,747.9	7,342.3	747
Massachusetts	Brayton Point	1619	4		0	1974	1974	DB	O	LNBO[b]	35	1,165.5	1,171.3	1,057.9	108
Massachusetts	Canal	1599	1		0	1968	1968	DB	O	LNBO[b]	35	4,801.2	4,327.8	4,358.0	443
Massachusetts	Canal	1599	2		0	1976	1976	DB	O	LNBO[b]	35	3,097.1	2,963.2	2,811.2	286
Massachusetts*	Cleary Flood	1682	8		1966	1966	1966	DB	O	LNB	35	19.5	17.4	17.7	2
Massachusetts*	Cleary Flood	1682	9		0	1975	1975	O	O	O	35	159.1	210.5	144.4	15
Massachusetts	Mystic	1588	7		0	1975	1975	T	O	U[b]		2,076.6	2,584.1	1,952.0	125
Massachusetts	New Boston	1589	1		0	1965	1965	DB	PNG	LNBO[b]	35	517.9	904.0	470.1	48
Massachusetts	New Boston	1589	2		0	1967	1967	DB	PNG	LNBO[b]	35	345.0	696.4	313.2	32
Massachusetts	Salem Harbor	1626	4		0	1972	1972	DB	O	LNB[b]	35	2,341.9	2,038.7	2,125.7	216
Massachusetts Total:												**27,867.9**		**25,362.5**	**2,505.3**
Michigan	Dan E Karn	1702	3	CS0009	1975	1974	1974	DB	O	U		1,408.3	1,055.7	1,323.8	84
Michigan	Dan E Karn	1702	4	CS0009	1977	1977	1977	DB	O	U		1,490.5	1,117.2	1,401.0	89
Michigan	Eckert Station	1831	4		1964	1964	1964	DB	C	U		602.4	469.5	566.2	36
Michigan	Eckert Station	1831	5		1968	1968	1968	DB	C	U		562.0	492.8	528.3	34
Michigan	Eckert Station	1831	6		1970	1970	1970	DB	C	U		745.2	536.7	700.5	45
Michigan	Erickson	1832	1		1973	1972	1973	DB	C	U		2,270.7	1,201.5	2,134.4	136
Michigan	Harbor Beach	1731	1		1968	1968	1968	DB	C	U		1,023.8	283.3	962.4	61
Michigan	J H Campbell	1710	1	CS0009	1962	1962	1962	T	C	LNC1	35	4,159.3	2,049.0	3,775.3	384
Michigan	J H Campbell	1710	2	CS0009	1967	1967	1967	CB	C	U		11,370.1	2,734.1	10,687.9	682
Michigan	James De Young	1830	5		1969	1969	0	WBF	C	U		748.0	204.0	703.1	45
Michigan	Monroe	1733	1	CS0012	1971	1971	1971	CB	C	U[b]		12,034.3	5,324.5	11,312.2	722
Michigan	Monroe	1733	2	CS0012	1973	1972	1973	CB	C	U[b]		8,658.8	3,831.0	8,139.2	520
Michigan	Monroe	1733	3	CS0034	1973	1973	1973	CB	C	U[b]		14,348.2	5,427.5	13,487.3	861
Michigan	Monroe	1733	4	CS0034	1974	1974	1974	CB	C	U[b]		15,894.2	6,012.3	14,940.5	954
Michigan	Presque Isle	1769	2	CS4	1962	0	1962	T	C	U[b]		194.1	68.9	182.4	12

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State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Michigan	Presque Isle	1769	3	CS4	1964	1963	1964	T	C	U[b]		1,044.6	371.0	982.0	63
Michigan	Presque Isle	1769	4	CS4	1966	1966	1966	T	C	U[b]		1,016.2	360.9	955.2	61
Michigan	Presque Isle	1769	5		1974	1974	1974	DB	C	U[b]		2,480.3	657.8	2,331.4	149
Michigan	Presque Isle	1769	6		1975	1975	1975	DB	C	U[b]		2,450.7	647.3	2,303.6	147
Michigan	St Clair	1743	7		1969	1969	1969	T	C	U		5,195.4	2,880.5	4,883.7	312
Michigan	Trenton Channel	1745	9A		0	1967	1968	T	C	U		5,401.2	3,655.8	5,077.1	324
Michigan Total:												**93,098.0**		**87,377.7**	**5,720.3**
Minnesota	Allen S King	1915	1		0	0	1968	C	C/O	U		18,479.2	3,856.1	17,370.4	1,109
Minnesota	Clay Boswell	1893	3	CS0003	1973	0	1973	T	C	U		4,393.0	2,792.3	4,129.4	264
Minnesota*	Fox Lake	1888	3		1962	0	1962	DB	C	U		115.7	115.2	108.7	7
Minnesota	Hoot Lake	1943	3		1964	0	1964	DB	C	LNB	35	550.5	493.2	499.6	51
Minnesota	Riverside	1927	8		1964	0	1964	DB	C/O	U		10,244.8	2,045.1	9,630.1	615
Minnesota	Sherburne County	6090	1	CS1	1976	0	1976	T	C/O	LNC1	35	6,018.0	5,091.0	5,462.5	556
Minnesota	Sherburne County	6090	2	CS1	1977	0	1977	T	C/O	LNC1	35	7,228.0	6,114.6	6,560.8	667
Minnesota	Silver Lake	2008	4		1969	0	0	DB	C	U		358.8	209.5	337.3	22
Minnesota Total:												**47,388.0**		**44,099.0**	**3,289.0**
Mississippi	Baxter Wilson	2050	1		1967	0	1966	T	G	U		5,411.3	2,777.0	5,086.6	325
Mississippi	Baxter Wilson	2050	2		1971	0	1971	T	O	U		8,465.0	2,621.0	7,957.1	508
Mississippi	Gerald Andrus	8054	1		1975	0	1975	O	O	U		10,034.4	2,872.0	9,432.4	602
Mississippi	Jack Watson	2049	3		1962	0	1962	T	G	U		189.7	361.7	178.3	11
Mississippi	Jack Watson	2049	4		1968	0	1968	DB	C	LNB	35	4,356.9	1,881.7	3,954.8	402
Mississippi	Jack Watson	2049	5		1973	0	1973	DB	C	LNB	35	13,368.0	4,187.2	12,134.0	1,234
Mississippi	Moselle	2070	1		1970	0	1970	DB	G	U		430.3	263.0	404.4	26
Mississippi	Moselle	2070	2		1970	0	1970	DB	G	U		699.3	404.4	657.4	42
Mississippi	Moselle	2070	3		1970	0	1970	DB	G	U		521.2	339.4	489.9	31
Mississippi	Victor J Daniel Jr	6073	1		1977	0	1977	T	C	U		5,615.6	3,976.4	5,278.7	337
Mississippi Total:												**49,091.8**		**45,573.6**	**3,518.2**
Missouri	Asbury	2076	1		1970	1970	1970	C	C	U		4,592.1	1,502.8	4,316.6	276
Missouri*	Blue Valley	2132	3		1965	1965	1965	T	C	U		328.8	198.2	309.1	20
Missouri	Columbia	2123	6	CS5	1963	0	0	S	C	U		150.4	61.0	141.4	9
Missouri	Columbia	2123	7	CS5	1965	1957	0	S	C	U		106.6	43.2	100.2	6
Missouri	Columbia	2123	8		1970	0	0	DB	G	U		14.7	4.1	13.8	1
Missouri	Hawthorn	2079	5		1969	1969	1969	T	C	U		486.6	299.6	457.4	29
Missouri	James River	2161	4		1964	1964	1964	DB	C	LNBO	35	1,167.8	513.9	1,060.0	108
Missouri	James River	2161	5		1970	1970	1970	DB	C	LNBO	35	2,483.5	919.8	2,254.3	229
Missouri	Labadie	2103	1		1970	1970	1970	T	C	LNB	35	2,456.9	4,548.0	2,230.2	227
Missouri	Labadie	2103	2		1971	1971	1971	T	C	LNB	35	3,240.9	5,116.2	2,941.7	299
Missouri	Labadie	2103	3		1972	1972	1972	T	C	LNB	35	2,425.7	4,045.7	2,201.8	224
Missouri	Labadie	2103	4		1973	1973	1973	T	C	LNB	35	2,302.9	3,656.0	2,090.3	213

The NOx control Technology scheduled to be added to the boiler: [a]LNB, [b]SCR, [c]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Missouri	Lake Road	2098	6		1989	1966	1967	C	C	U		3,098.8	744.7	2,912.8	186
Missouri	Montrose	2080	3	CS023	1964	1964	1964	T	C	U		2,262.9	1,324.5	2,127.2	136
Missouri	New Madrid	2167	1		0	1972	1972	C	C	U[b]		29,422.1	5,154.2	27,656.7	1,765
Missouri	New Madrid	2167	2		0	1977	1977	C	C	U[b]		22,799.4	3,951.0	21,431.5	1,368
Missouri	Rush Island	6155	1		1976	1976	1976	T	C	LNB	35	2,710.8	4,110.8	2,460.6	250
Missouri	Rush Island	6155	2		1977	1977	1977	T	C	LNB	35	2,981.3	4,814.5	2,706.1	275
Missouri	Sibley	2094	2	CS0001	1962	1962	1962	C	C	U		1,828.8	363.1	1,719.1	110
Missouri	Sibley	2094	3	CS0001	1969	1969	1969	C	C	U		15,086.0	2,994.9	14,180.9	905
Missouri	Sioux	2107	1		1967	1967	1967	C	C	U		18,809.2	3,306.0	17,680.6	1,129
Missouri	Sioux	2107	2		1968	1968	1968	C	C	U		5,361.2	2,632.8	5,039.5	322
Missouri	Southwest	6195	1		0	1976	1976	DB	C	U		2,546.9	1,783.5	2,394.0	153
Missouri	Thomas Hill	2168	MB1		0	1966	1966	C	C	U		6,783.2	1,663.9	6,376.2	407
Missouri	Thomas Hill	2168	MB2		0	1969	1969	C	C	U		14,940.8	2,859.2	14,044.4	896
Missouri Total:												**148,388.2**		**138,846.2**	**9,542.0**
New Hampshire	Merrimack	2364	2		1968	0	1968	C	C	SCR	94	4,627.4	2,356.1	0.0	4,627
New Hampshire	Newington	8002	1		1974	0	1974	T	O	H2O	35	2,416.0	2,210.2	2,193.0	223
New Hampshire Total:												**7,043.4**		**2,193.0**	**4,850.4**
New Jersey	B L England	2378	1		1962	1962	1962	C	C	U		2,168.0	848.2	2,037.9	130
New Jersey	B L England	2378	2		1964	1964	1964	C	C	U		2,164.9	922.0	2,035.0	130
New Jersey	B L England	2378	3		1974	0	1974	DB	O	U		269.8	314.1	253.6	16
New Jersey	Gilbert	2393	4		1974	1977	0	CC	DSL	O	35	56.1	118.5	50.9	5
New Jersey	Gilbert	2393	5		1974	1977	0	CC	DSL	O	35	67.6	121.9	61.3	6
New Jersey	Gilbert	2393	6		1974	1977	0	CC	DSL	O	35	58.5	104.8	53.1	5
New Jersey	Gilbert	2393	7		1974	1977	0	CC	DSL	O	35	62.4	110.2	56.7	6
New Jersey	Hudson	2403	1		1964	1964	1964	C	PNG	H2O	35	315.0	310.5	285.9	29
New Jersey	Hudson	2403	2		1968	1968	1967	DB	C	LNBO[c]	35	7,576.4	3,382.5	6,877.1	699
New Jersey Total:												**12,738.7**		**11,711.5**	**1,027.2**
New York	Arthur Kill	2490	30	CS0002	0	1969	1969	T	O	U		1,024.4	1,983.0	963.0	61
New York	Astoria	8906	50		0	1962	1962	T	O	U		1,259.3	2,629.6	1,183.8	76
New York	Bowline Point	2625	1		1972	1972	1972	T	O	O	35	1,808.8	2,269.4	1,641.8	167
New York	Bowline Point	2625	2		1974	1974	1974	DB	O	LNBO	35	1,813.1	1,969.1	1,645.7	167
New York	Charles Poletti	2491	1		0	1976	0	DB	O	LNBO	35	2,014.1	2,419.2	1,828.2	186
New York	Danskammer	2480	4		1967	1967	1987	T	C	O	35	2,965.2	1,688.8	2,691.5	274
New York	E F Barrett	2511	10		1971	1956	1956	T	G	O	35	517.5	1,076.3	469.7	48
New York	E F Barrett	2511	20		0	1963	1963	T	G	OFA,CM	35	312.3	986.9	283.5	29
New York	Lovett	2629	4		1966	1966	1966	DB	C	LNB	35	2,221.3	1,313.6	2,016.3	205
New York	Lovett	2629	5		1969	1969	1969	DB	C	LNB	35	1,989.1	1,223.3	1,805.5	184
New York	Northport	2516	1		0	1967	1967	T	O	OFA	35	1,494.5	2,491.0	1,356.6	138
New York	Northport	2516	2		1968	1968	1968	T	O	OFA	35	1,272.6	2,457.6	1,155.1	117

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [C]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
New York	Northport	2516	3		1972	1972	1972	T	O	OFA	35	1,468.7	1,483.9	1,333.2	136
New York	Northport	2516	4		1977	1977	1977	T	O	OFA	35	1,090.6	2,239.0	990.0	101
New York	Oswego	2594	5		0	0	1976	DB	O	U		803.3	891.9	755.1	48
New York	Ravenswood	2500	10		0	1962	1963	T	O	U		222.1	584.9	208.7	13
New York	Ravenswood	2500	20		0	1963	1963	T	O	U		639.1	1,578.8	600.8	38
New York	Ravenswood	2500	30		0	1965	1965	T	O	U		2,967.8	3,887.0	2,789.7	178
New York	Roseton	8006	1		1974	1974	1974	T	O	O	35	2,025.7	2,628.8	1,838.7	187
New York	Roseton	8006	2		1974	1974	1974	T	O	O	35	2,456.4	3,069.8	2,229.7	227
New York Total:												**30,366.1**		**27,786.5**	**2,579.6**
North Carolina	Asheville	2706	1		1964	1964	1964	DB	C	U[d]		3,641.6	1,464.6	3,423.1	218
North Carolina	Asheville	2706	2		1971	1971	1971	DB	C	U[d]		2,662.5	1,631.5	2,502.8	160
North Carolina	Belews Creek	8042	1		1974	1974	1974	CB	C	U[b]		44,867.4	8,573.3	42,175.3	2,692
North Carolina	Belews Creek	8042	2		1975	1975	1975	CB	C	LNB[b]	35	23,384.6	7,497.6	21,226.0	2,159
North Carolina	Buck	2720	7		1970	0	1942	T	C	U		282.6	137.8	265.6	17
North Carolina	Buck	2720	8		1970	1953	1953	T	C	LNB	35	1,566.0	827.6	1,421.4	145
North Carolina	Buck	2720	9		1970	1953	1953	T	C	LNB	35	1,666.5	881.2	1,512.7	154
North Carolina	Cliffside	2721	5		1972	1972	1972	T	C	LNC1	35	7,159.5	3,497.9	6,498.6	661
North Carolina	L V Sutton	2713	3		1972	1972	1972	DB	C	U		4,188.3	2,320.2	3,937.0	251
North Carolina	Lee	2709	3		1962	1962	1962	DB	C	U		2,406.3	1,483.3	2,262.0	144
North Carolina	Marshall	2727	1		1965	1965	1965	T	C	LNB	35	4,956.1	2,560.6	4,498.6	457
North Carolina	Marshall	2727	2		1966	1966	1966	T	C	LNB	35	5,454.5	2,799.3	4,951.0	503
North Carolina	Marshall	2727	3		1969	1969	1969	T	C	LNB	35	6,869.7	3,512.3	6,235.6	634
North Carolina	Marshall	2727	4		1970	1970	1970	T	C	LNB	35	9,387.6	4,698.2	8,521.1	867
North Carolina	Riverbend	2732	10		1969	1954	1954	T	C	LNC1	35	1,375.7	755.6	1,248.7	127
North Carolina	Riverbend	2732	8		1969	1952	1952	T	C	LNC1	35	419.4	254.0	380.7	39
North Carolina	Riverbend	2732	9		1969	1954	1954	T	C	LNC1	35	1,253.5	716.0	1,137.8	116
North Carolina	Roxboro	2712	1		1966	1966	1966	DB	C	LNB[b]	35	6,184.4	2,631.5	5,613.5	571
North Carolina	Roxboro	2712	2		1968	1968	1968	T	C	U[b]		6,501.0	4,901.3	6,111.0	390
North Carolina	Roxboro	2712	3A	CS0003	0	1973	1973	DB	C	LNB[b]	35	4,732.5	2,730.0	4,295.6	437
North Carolina	Roxboro	2712	3B	CS0003	0	1973	1973	DB	C	LNB[b]	35	4,822.8	2,782.2	4,377.7	445
North Carolina Total:												**143,782.5**		**132,595.7**	**11,186.8**
Ohio*	Ashtabula	2835	10	CS1	0	1972	1948	DB	C	U		151.4	58.5	142.4	9
Ohio*	Ashtabula	2835	11	CS1	0	1972	1948	DB	C	U		133.1	51.4	125.1	8
Ohio*	Ashtabula	2835	8	CS1	1953	1972	1948	DB	C	U		82.7	32.0	77.7	5
Ohio*	Ashtabula	2835	9	CS1	1953	1972	0	DB	C	U		0.0	0.0	0.0	0
Ohio	Avon Lake	2836	10		1973	1949	1949	T	C	U		707.1	352.0	664.7	42
Ohio	Avon Lake	2836	12		0	1970	1970	CB	C	U		18,358.4	4,127.9	17,256.9	1,102

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [C]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Ohio	Avon Lake	2836	9		1970	1949	0	na	na	U		0.0	0.0	0.0	0
Ohio	Bay Shore	2878	3	XS14	1963	1963	1963	DB	C	U		136.4	870.1	128.2	8
Ohio	Bay Shore	2878	4	XS14	1968	1968	1968	DB	C	U		191.9	1,224.0	180.3	12
Ohio	Cardinal	2828	1		1967	1966	1966	CB	C	U[c]		7,740.5	3,179.6	7,276.1	464
Ohio	Cardinal	2828	2		1967	1967	1967	CB	C	U[c]		15,066.6	3,320.0	14,162.6	904
Ohio	Cardinal	2828	3		1977	1977	1977	DB	C	U[c]		10,406.8	3,841.5	9,782.4	624
Ohio	Conesville	2840	3		1962	1962	1962	DB	C	LNB	35	1,161.1	564.0	1,053.9	107
Ohio	Conesville	2840	4		1973	1973	1973	T	C	U		8,332.5	4,349.1	7,832.5	500
Ohio	Conesville	2840	5	CS056	1976	1976	1976	T	C	U		4,040.8	2,297.3	3,798.4	242
Ohio	Eastlake	2837	5		1972	1972	1972	CB	C	U		12,907.2	3,316.4	12,132.8	774
Ohio	Gen J M Gavin	8102	1		1974	1974	1974	CB	C	U[b] ǂ		19,463.8	10,178.9	18,296.0	1,168
Ohio	Gen J M Gavin	8102	2		1975	1975	1975	CB	C	U[b] ǂ		32,472.5	7,533.2	30,524.2	1,948
Ohio	Hamilton	2917	9		0	1975	1974	T	C	U		767.2	351.6	721.2	46
Ohio	J M Stuart	2850	1		1971	1971	1971	CB	C	U		12,714.7	3,874.6	11,951.8	763
Ohio	J M Stuart	2850	2		1970	1970	1970	CB	C	U		12,995.5	3,685.2	12,215.8	780
Ohio	J M Stuart	2850	3		1972	1972	1972	CB	C	U		10,959.9	3,993.2	10,302.3	658
Ohio	J M Stuart	2850	4		1974	1974	1974	CB	C	O	35	13,043.8	4,838.1	11,839.7	1,204
Ohio	Lake Road	2908	6		0	0	1967	na	na	na		0.0	0.0	0.0	0
Ohio	Lake Shore	2838	18		1962	0	1962	T	C	U		749.8	360.6	704.8	45
Ohio	Miami Fort	2832	7		1975	1975	1975	CB	C	U[b]		10,622.1	4,604.5	9,984.7	637
Ohio	Miami Fort	2832	8		1978	1977	1978	DB	C	LNB[b]	35	10,460.5	4,236.1	9,494.9	966
Ohio	Muskingum River	2872	5		1968	1968	1968	CB	C	U		11,764.4	4,083.9	11,058.5	706
Ohio	W H Sammis	2866	4	CS0002	1962	1962	1962	DB	C	U		6,015.9	1,587.1	5,655.0	361
Ohio	W H Sammis	2866	5		1967	1967	1967	DB	C	LNB	35	4,764.4	1,998.8	4,324.6	440
Ohio	W H Sammis	2866	6		1969	1969	1969	DB	C	LNBO	35	11,796.5	5,233.9	10,707.6	1,089
Ohio	W H Sammis	2866	7		1971	1971	1971	CB	C	U		20,599.5	4,307.0	19,363.5	1,236
Ohio	Walter C Beckjord	2830	5		1962	1962	1962	T	C	U		3,631.6	1,891.0	3,413.7	218
Ohio	Walter C Beckjord	2830	6		1969	1969	1969	T	C	U		5,138.0	3,375.7	4,829.7	308
Ohio Total:												**267,376.7**		**250,002.1**	**17,374.5**
Pennsylvania	Bruce Mansfield	6094	1		1976	1975	1976	DB	C	LNBO	35	7,406.0	4,596.6	6,722.4	684
Pennsylvania	Bruce Mansfield	6094	2		1977	1977	1977	DB	C	U		7,804.4	5,139.0	7,336.2	468
Pennsylvania	Brunner Island	3140	2	CS102	1965	1965	1965	T	C	LNC3	35	3,225.4	2,036.0	2,927.7	298
Pennsylvania	Brunner Island	3140	3		1969	1968	1969	T	C	LNC3	35	6,728.7	4,474.6	6,107.6	621
Pennsylvania	Cheswick	8226	1		1970	1970	1970	T	C	LNC2	35	5,244.5	3,728.1	4,760.4	484
Pennsylvania	Conemaugh	3118	1		1970	1970	1970	T	C	U		11,831.2	7,932.2	11,121.3	710
Pennsylvania	Conemaugh	3118	2		1970	1971	1971	T	C	U		8,933.3	6,382.1	8,397.3	536
Pennsylvania	Eddystone	3161	3	CS034	1974	0	1974	T	O	U		345.1	375.5	324.4	21
Pennsylvania	Eddystone	3161	4	CS034	1976	0	1976	T	O	U		404.8	440.4	380.5	24
Pennsylvania	Hatfield's Ferry	3179	1	XS123	1969	1969	1969	CB	C	LNCB	35	7,150.9	3,487.6	6,490.8	660

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [c]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Pennsylvania	Hatfield's Ferry	3179	2	XS123	1970	1970	1970	CB	C	LNCB	35	5,209.1	2,540.6	4,728.3	481
Pennsylvania	Hatfield's Ferry	3179	3	XS123	1971	1971	1971	CB	C	LNCB	35	7,706.8	3,758.8	6,995.4	711
Pennsylvania	Homer City	3122	1		1969	1969	1969	DB	C	LNBO[b]	35	9,903.8	5,251.0	8,989.6	914
Pennsylvania	Homer City	3122	2		1969	1969	1969	DB	C	LNBO[b]	35	8,786.5	4,771.3	7,975.4	811
Pennsylvania	Homer City	3122	3		1977	1977	1977	DB	C	LNBO[b]	35	7,893.4	4,475.0	7,164.8	729
Pennsylvania	Keystone	3136	1		1967	1967	1967	T	C	LNC3	35	9,574.1	6,365.8	8,690.4	884
Pennsylvania	Keystone	3136	2		1968	1968	1968	T	C	LNC3	35	10,858.3	7,346.0	9,856.0	1,002
Pennsylvania	Martins Creek	3148	3		1975	1975	1975	T	O	U		1,047.7	930.2	984.9	63
Pennsylvania	Martins Creek	3148	4		1977	1976	1977	T	O	U		1,686.9	1,176.4	1,585.7	101
Pennsylvania	Mitchell	3181	3		1963	0	1949	DVF	DSL	U		7.1	10.9	6.7	0
Pennsylvania	Mitchell	3181	33		0	1963	1963	T	C	U		2,798.6	1,759.9	2,630.6	168
Pennsylvania	Montour	3149	1		1972	1971	1972	T	C	LNC3[b]	35	7,446.1	4,289.3	6,758.8	687
Pennsylvania	Montour	3149	2		1973	1973	1973	T	C	LNC3[b]	35	8,487.4	5,048.8	7,703.9	783
Pennsylvania	New Castle	3138	5		1964	1964	1964	DB	C	U		1,469.7	707.3	1,381.5	88
Pennsylvania	Portland	3113	2		1962	1962	1962	T	C	LNC3	35	1,589.8	1,341.4	1,443.0	147
Pennsylvania	Warren	3132	3	CS3	1972	0	0	DB	C	U		262.2	106.1	246.5	16
Pennsylvania Total:												**143,801.9**		**131,710.1**	**12,091.8**
South Carolina	Canadys Steam	3280	CAN1		0	1962	1962	T	C	U		863.0	384.5	811.2	52
South Carolina	Canadys Steam	3280	CAN2		0	1964	1964	T	C	U		706.5	317.6	664.1	42
South Carolina	Canadys Steam	3280	CAN3		0	1967	1967	T	C	U		1,359.1	648.4	1,277.5	82
South Carolina	Dolphus M Grainger	3317	1		1966	1966	1966	DB	C	LNB	35	1,053.2	547.3	956.0	97
South Carolina	Dolphus M Grainger	3317	2		1966	1966	1966	DB	C	U		2,087.9	508.9	1,962.6	125
South Carolina	Jefferies	3319	3		1970	1969	1970	DB	C	LNB	35	2,526.3	1,016.0	2,293.1	233
South Carolina	Jefferies	3319	4		1970	1970	1970	DB	C	LNB	35	2,653.0	1,282.4	2,408.1	245
South Carolina	Wateree	3297	WAT1		0	1970	1970	DB	C	U[b]		5,249.5	2,437.8	4,934.5	315
South Carolina	Wateree	3297	WAT2		0	1971	1971	DB	C	U[b]		5,118.8	2,422.5	4,811.6	307
South Carolina	Williams	3298	WIL1		0	1973	1973	T	C	U[b]		11,993.1	5,402.3	11,273.5	720
South Carolina	Winyah	6249	1		1975	1974	1975	DB	C	LNBO	35	4,611.0	2,403.5	4,185.4	426
South Carolina	Winyah	6249	2		1977	1977	1977	DTF	C	LNBO	35	5,071.6	2,119.4	4,603.4	468
South Carolina Total:												**43,292.8**		**40,181.0**	**3,111.7**
Tennessee	Bull Run	3396	1		1967	1967	1967	T	C	U[b]		13,527.8	4,641.4	12,716.1	812
Tennessee	Cumberland	3399	1	1	1973	1972	1973	CB	C	U[b]		53,393.4	8,408.3	50,189.8	3,204
Tennessee	Cumberland	3399	2		1973	1973	1973	CB	C	U[b]		29,277.9	12,078.5	27,521.2	1,757
Tennessee Total:												**96,199.1**		**90,427.2**	**5,771.9**
Virginia	Chesapeake	3803	4		0	1962	1962	T	C	O[b]	35	3,857.3	2,005.1	3,501.2	356
Virginia	Chesterfield	3797	5		1964	1964	1964	T	C	LNC2[b]	35	3,981.1	2,443.0	3,613.6	367
Virginia	Chesterfield	3797	6		1969	1969	1969	T	C	LNC3[b]	35	9,324.6	3,531.2	8,463.8	861

The NOx control Technology scheduled to be added to the boiler: [a]LNB, [b]SCR, [c]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

State	Plant Name	ORISPL	Unit ID	Associated Stack	EIA99	EGU8	EIA-767	Boiler Type	Primary Fuel	NOx Controls	Assumed NOx Control Efficiency	1999 NOx (tons)	1999 Heat Input (mmBtu/hr)	Potential NOx Reductions (tons)	Estimated NOx Emissions (tons)
Virginia	Possum Point	3804	4		1962	1962	1962	T	C	LNC3	35	2,846.0	1,797.4	2,583.3	263
Virginia	Possum Point	3804	5		1975	0	1975	T	O	U		683.7	702.0	642.7	41
Virginia	Yorktown	3809	3		1974	1974	1974	T	O	U		5,614.6	2,814.6	5,277.8	337
Virginia Total:												**26,307.3**		**24,082.4**	**2,224.9**
West Virginia	Fort Martin	3943	1		1967	1967	1967	T	C	U		13,057.8	4,531.3	12,274.3	783
West Virginia	Fort Martin	3943	2		1968	1968	1968	CB	C	U		17,364.4	4,263.2	16,322.5	1,042
West Virginia	Harrison	3944	1	XS123	1972	1972	1972	DB	C	LNB[b]	35	12,236.2	5,824.5	11,106.7	1,129
West Virginia	Harrison	3944	2	XS123	1973	1973	1973	DB	C	LNB[b]	35	10,725.5	5,105.5	9,735.5	990
West Virginia	Harrison	3944	3	XS123	1974	1974	1974	DB	C	LNB[b]	35	11,746.2	5,591.3	10,661.9	1,084
West Virginia	John E Amos	3935	1	CS012	1971	1971	1971	DB	C	LNB	35	11,675.1	5,069.0	10,597.4	1,078
West Virginia	John E Amos	3935	2	CS012	1972	1972	1972	DB	C	LNB	35	13,960.3	6,061.2	12,671.6	1,289
West Virginia	John E Amos	3935	3		1973	1973	1973	CB	C	U[b]		29,971.7	8,916.1	28,173.4	1,798
West Virginia	Mitchell	3948	1	CS012	1971	1971	1971	DB	C	LNB	35	12,052.3	4,860.3	10,939.8	1,113
West Virginia	Mitchell	3948	2	CS012	1971	1971	1971	DB	C	LNB	35	12,520.5	5,049.2	11,364.7	1,156
West Virginia	Mt Storm	3954	1	CS0	1965	1965	1965	T	C	LNC1[b]	35	13,134.3	4,542.1	11,921.9	1,212
West Virginia	Mt Storm	3954	2	CS0	1966	1966	1966	T	C	LNC1[b]	35	11,893.4	4,183.3	10,795.6	1,098
West Virginia	Mt Storm	3954	3		1973	1973	1973	T	C	LNC1[b]	35	13,612.8	4,500.0	12,356.2	1,257
West Virginia Total:												**183,950.5**		**168,921.7**	**15,028.9**
Wisconsin	Blount Street	3992	11		0	0	1964	DB	G	U		6.3	6.1	5.9	0
Wisconsin*	Blount Street	3992	3		0	0	1968	O	G	U		73.1	22.7	68.7	4
Wisconsin	Columbia	8023	1		1975	1975	1975	T	C	U		7,173.8	4,376.7	6,743.4	430
Wisconsin	Edgewater	4050	4		1969	1969	1969	C	C	U		10,247.6	2,119.8	9,632.7	615
Wisconsin	Genoa	4143	1		0	1969	1969	T	C	LNC3	35	4,150.7	2,328.2	3,767.5	383
Wisconsin	Manitowoc	4125	6	CS0020	1964	0	0	S	C	U		170.8	121.6	160.6	10
Wisconsin	Nelson Dewey	4054	2	CS1	1962	1962	1962	C	C	CM	35	2,831.5	809.8	2,570.1	261
Wisconsin	Pulliam	4072	8		1964	1964	1964	DB	C	LNB	35	1,872.4	1,186.7	1,699.5	173
Wisconsin	South Oak Creek	4041	7	CS4	1965	1965	1965	T	C	LNB[b]	35	3,774.2	2,292.7	3,425.8	348
Wisconsin	South Oak Creek	4041	8	CS4	1967	1967	1967	T	C	LNB[b]	35	3,701.9	2,248.8	3,360.2	342
Wisconsin	Valley (WEPCO)	4042	1	CS1	1968	1968	1968	DB	C	LNB[b]	35	994.5	467.1	902.7	92
Wisconsin	Valley (WEPCO)	4042	2	CS1	1969	1968	1968	DB	C	LNB[b]	35	995.5	467.6	903.6	92
Wisconsin	Valley (WEPCO)	4042	3	CS2	1969	1969	1969	DB	C	LNB[b]	35	1,080.3	485.8	980.6	100
Wisconsin	Valley (WEPCO)	4042	4	CS2	0	1969	1969	DB	C	LNB[b]	35	1,101.3	495.3	999.7	102
Wisconsin Total:												**38,173.8**		**35,221.0**	**2,952.8**
Total NOx Emissions in Source Region:												**2,193,836**		**2,032,268**	**161,569**

The NOx control Technology scheduled to be added to the boiler:[a]LNB, [b]SCR, [c]SNCR, and [d]AEFLGR. This information is based on the Institute of Clean Air Companies Table, "NOx control retrofit project information."

Appendix C: Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations; Proposed Rule

Friday,
July 20, 2001

Part III

Environmental Protection Agency

40 CFR Part 51

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[FRL–6934–4]

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The purpose of this proposal is to request comment on EPA's proposed guidelines for implementation of the best available retrofit technology (BART) requirements under the regional haze rule which was published on July 1, 1999 (64 FR 35714). We propose to add the guidelines as appendix Y to 40 CFR part 51. We propose to add regulatory text requiring that these guidelines be used for addressing BART determinations under the regional haze rule. In addition, we are proposing one revision to guidelines issued in 1980 for facilities contributing to ''reasonably attributable'' visibility impairment.

DATES: We are requesting written comments by September 18, 2001. The EPA has scheduled two public hearings on this proposed rule. The first public hearing will be held on August 21 in Arlington, Virginia. The second public hearing will be held on August 27 in Chicago, Illinois. (See following section for times and addresses.)

ADDRESSES: *Docket.* Information related to the BART guidelines is available for inspection at the Air and Radiation Docket and Information Center, docket number A–2000–28. The docket is located at the U.S. Environmental Protection Agency, 401 M Street, SW, Room M–1500, Washington, DC 20460, telephone (202) 260–7548. The docket is available for public inspection and copying between 8:00 a.m. and 5:30 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

You should submit comments on today's proposal and the materials referenced herein (in duplicate if possible) to the Air and Radiation Docket and Information Center (6102), Attention: Docket No. A–2000–28, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW, Washington, DC 20460. You may also submit comments to EPA by electronic mail at the following address: A-and-R-Docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. All comments and data in electronic form must be identified by the docket number [A–2000–28]. Electronic comments on this proposed rule also may be filed online at many Federal Depository Libraries.

Public Hearings. The first public hearing on this proposed rule will be held on August 21 at 10:00 am at the Crowne Plaza Hotel, 1489 Jefferson Davis Highway, Arlington, VA 22202. The hotel is located near the Crystal City metro stop. The second public hearing will be held on August 27 at 10:00 am at the Metcalfe Federal Building, Room 331, 77 West Jackson Boulevard, Chicago, IL 60604.

If you wish to attend either public hearing or wish to present oral testimony, please send notification no later than one week prior to the date of the public hearing to Ms. Nancy Perry, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5628, e-mail *perry.nancy@epa.gov.*

Oral testimony will be limited to 5 minutes each. The hearing will be strictly limited to the subject matter of the proposal, the scope of which is discussed below. Any member of the public may file a written statement by the close of the comment period. Written statements (duplicate copies preferred) should be submitted to Docket No. A–2000–28 at the address listed above for submitting comments. The hearing schedule, including lists of speakers, will be posted on EPA's webpage at *http://www.epa.gov/air/visibility/whatsnew.html.* A verbatim transcript of the hearings and written statements will be made available for copying during normal working hours at the Air and Radiation Docket and Information Center at the address listed above.

FOR FURTHER INFORMATION CONTACT: Tim Smith (telephone 919–541–4718), Mail Drop 15, EPA, Air Quality Strategies and Standards Division, Research Triangle Park, North Carolina, 27711. Internet address: smith.tim@epa.gov.

SUPPLEMENTARY INFORMATION: We are providing the public with the opportunity to comment on EPA's Proposed BART Guidelines and the accompanying regulatory text.

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K. Guidelines for BART Determinations Under the Regional Haze Rule

I. Background on BART Guidelines

A. Commitment in the Preamble to the Regional Haze Rule

The EPA included in the final regional haze rule a requirement for BART for certain large stationary sources put in place between 1962 and 1977. We discuss these requirements in detail in the preamble to the final rule (see 64 FR 35737–35743). The regulatory requirements for BART are codified in 40 CFR 51.308(e). In the preamble, we committed to issuing further guidelines to clarify the requirements of the BART provision. The purpose of this notice is to provide the public with an opportunity to comment on the draft guidelines and the accompanying regulatory text.

B. Statutory Requirement for BART Guidelines

Section 169A(b)(1) of the Clean Air Act (CAA) requires EPA to provide guidelines to States on the implementation of the visibility program. Moreover, the last sentence of section 169A(b) states:

> In the case of a fossil-fuel fired generating powerplant having a capacity in excess of 750 megawatts, the emission limitations required under this paragraph shall be determined pursuant to guidelines, promulgated by the Administrator under paragraph (1)

We interpret this statutory requirement as clearly requiring EPA to publish BART guidelines and to require that States follow the guidelines in establishing BART emission limitations for power plants with a total capacity exceeding the 750 megawatt cutoff. The statute is less clear regarding whether the guidelines must be used for sources other than 750 megawatt power plants; however, today's proposed rule would require States to use the guidelines for all of the 26 categories. We believe it is reasonable that consistent, rigorous approaches be used for all BART source categories. In addition, we believe it is important to provide for consistent approaches to identifying the sources in the remaining categories which are BART-eligible. We request comment on whether the regional haze rule should: (1) Require use of the guidelines only for 750 megawatt utilities, with the guidelines applying as guidance for the remaining categories, or (2)require use of the guidelines for all of the affected source categories.

II. Proposed Amendments to Part 51

We propose:

(1) BART guidelines, to be added as appendix Y to 40 CFR part 51,

(2) regulatory text, to be added as sub-paragraph 51.308(e)(1)(C), requiring the use of the guidelines.

Overview of Proposed Appendix Y

We discuss the following general topics in appendix Y, which are organized into the following sections:

—*Introduction.* Section I provides an overview of the BART requirement in the regional haze rule and in the CAA, and an overview of the guidelines.

—*Identification of BART-eligible sources.* Section II is a step-by-step process for identifying BART-eligible sources.

—*Identification of sources subject to BART.* Sources ''subject to BART'' are those BART-eligible sources which ''emit a pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area.'' We discuss considerations for identifying sources subject to BART in section III of the proposed appendix Y.

—*Engineering analysis.* For each source subject to BART, the next step is to conduct an engineering analysis of emissions control alternatives. This step requires the identification of available, technically feasible, retrofit technologies, and for each technology identified, analysis of the cost of compliance, and the energy and non-air quality environmental impacts, taking into account the remaining useful life and existing control technology present at the source. For each source, a ''best system of continuous emission reduction'' is selected based upon this engineering analysis. Guidelines for the engineering analysis are described in section IV of the proposed appendix Y.

—*Cumulative air quality analysis.* The rule requires a cumulative analysis of the degree of visibility improvement that would be achieved in each Class I area as a result of the emissions reductions achievable from all sources subject to BART. The establishment of BART emission limits must take into account the cumulative impact overall from the emissions reductions from all of the source-specific ''best technologies'' identified in the engineering analysis. Considerations for this cumulative air quality analysis are discussed in section V.

—*Emission limits.* Considering the engineering analysis and the cumulative air quality analysis, States must establish enforceable limits, including a deadline for compliance, for each source subject to BART. Considerations related to these limits and deadlines are discussed in section VI.

—*Trading program alternative.* General guidance on how to develop an emissions trading program alternative to BART is contained in section VII of the guidance. (Note that more comprehensive guidance for emission trading programs generally is described in Section VII).

Regulatory Text

The proposed regulatory text would require that States follow the guidelines for all BART determinations required under the regional haze rule. We request public comment on all provisions of the guidelines and on the accompanying regulatory text.

III. Revision to 1980 BART Guidelines for ''Reasonably Attributable'' Visibility Impairment

As noted above, the primary purpose of today's proposed rule is to provide BART guidelines for the regional haze program. In addition, however, we are making limited revisions to longstanding guidelines for BART under the 1980 visibility regulations for localized visibility impairment that is ''reasonably attributable'' to one or a few sources.[1] The visibility regulations require that States must use a 1980 guidelines document when conducting BART analyses for certain power plants for reasonably attributable visibility impairment. The regulatory text for this requirement is found in 40 CFR 51.302(c)(4)(iii), as follows:

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to ''Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities'' (1980), which is incorporated by reference, exclusive of appendix E, which was published in the **Federal Register** on February 6, 1980 (45 FR 8210). It is EPA publication No. 450/3–80–009b and is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161. It is also available for inspection at the Office of the Federal Register Information Center, 800 North Capitol NW., suite 700, Washington, DC.

While the analytical process set forth in these guidelines is still generally acceptable for conducting BART analyses for ''reasonably attributable'' visibility impairment, there are statements in the 1980 BART Guidelines that could be read to indicate that the new source performance standards (NSPS) may be considered to represent the maximum achievable control for existing sources. While this may have been the case in 1980 (e.g., the NSPS for sulfur dioxide (SO_2) from boilers had been recently issued in June 1979), the maximum achievable control levels for recent plant retrofits have exceeded NSPS levels. Thus, in order to ensure that there is no confusion regarding how the 1980 guidelines should be interpreted, EPA has included the following discussion in today's action and proposes limited clarifying changes to the visibility regulations.

In various sections of the 1980 guideline, the discussion indicates that the NSPS in 1980 was considered to generally represent the most stringent option these sources could install as BART (i.e., maximum achievable level of control). See, e.g., 1980 BART Guidelines at pp. 8, 11 and 21. For example, a flowchart in the 1980 guidelines indicates that if States establish a BART emission limitation equivalent to NSPS for the source, then the State would not need to conduct a full-blown analysis of control alternatives. See, 1980 BART Guidelines at p. 8. Similarly, the visibility analysis described in the guideline assumes as a starting point the level of controls currently achieved by the NSPS. See, 1980 Guideline at p. 11. In the 20-year period since these guidelines were developed, there have been advances in SO_2 control technologies that have significantly increased the level of control that is feasible, while costs per ton of SO_2 controlled have declined.

[1] U.S. Environmental Protection Agency, *Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities,* EPA–450/3–80–009b, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., November 1980 (1980 BART Guidelines).

This is demonstrated by a number of recent retrofits or binding agreements to retrofit coal-fired power plants in the western United States. These plants include: Hayden (CO), Navajo (AZ), Centralia (WA), and Mohave (NV). These cases have shown that control options exist which can achieve a significantly greater degree of control than the 70 percent minimum required by the NSPS for power plants emitting SO_2 at less than 0.60 lb/million Btu heat input. These retrofits have achieved, or are expected to achieve, annual SO_2 reductions in the 85 to 90 percent range. Additionally, an EPA report [2] published in October 2000 shows that the SO_2 removal for flue gas desulfurization systems installed in the 1990s is commonly 90 percent or more for both wet and dry scrubbers, well above the minimum 70 percent control required by the 1979 NSPS.[3]

Given the advances in control technology that have occurred over the past 20 years, we believe that it should be made clear that the BART analyses for reasonably attributable visibility impairment should not be based on an assumption that the NSPS level of control represents the maximum achievable level of control. While it is possible that a detailed analysis of the BART factors could result in the selection of a NSPS level of control, we believe that States should only reach this conclusion based upon an analysis of the full range of control options, including those more stringent than a NSPS level of control. In sum, all ''reasonably attributable'' BART analyses should consider control levels more stringent than NSPS, including maximum achievable levels, and evaluate them in light of the statutory factors.

IV. Administrative Requirements

In preparing any proposed rule, EPA must meet the administrative requirements contained in a number of statutes and executive orders. In this section of the preamble, we discuss how today's regulatory proposal for BART guidelines addresses these administrative requirements.

[2] U.S. Environmental Protection Agency, *Controlling SO_2 Emissions: A Review of Technologies,* EPA–600/R–00–093, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, October 2000, pp 32–34.

[3] Note also that part II of the 1980 BART guidelines includes an analysis of 90 percent control for three power plants burning low-sulfur coal.

A. Regulatory Planning and Review by the Office of Management and Budget (OMB) (Executive Order 12866)

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

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

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

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

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

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' and EPA has submitted it to OMB for review. The drafts of rules submitted to OMB, the documents accompanying such drafts, written comments thereon, written responses by EPA, and identification of the changes made in response to OMB suggestions or recommendations are available for public inspection at EPA's Air and Radiation Docket and Information Center (Docket Number A–2000–28).

Because today's guidelines clarify, and do not change, the existing rule requirements of the regional haze rule, the guidelines do not have any effect on the Regulatory Impact Analysis (RIA) that was previously prepared for the regional haze rule. This RIA is available in the docket for the regional haze rule (A–95–38). As part of the analyses included in this RIA, we provided an estimate of the potential cost of control to BART sources that is an average of the costs associated with the least stringent illustrative progress goal (1.0 deciview reduction over a 15-year period) and the most stringent illustrative progress goal (10 percent deciview reduction over a 10-year period). The annual cost of control to BART sources associated with the final Regional Haze rulemaking in 2015, the year for which impacts are projected, is $72 million (1990 dollars).

This estimate of the control costs for BART sources for the year 2015 was calculated after taking into account a regulatory baseline projection for the year 2015. The baseline for these calculations included control measures estimated to be needed for partial attainment of the PM and ozone NAAQS issued in 1997. These baseline estimates were contained in an analysis prepared for the RIA for the PM and ozone NAAQS, and are summarized in the RIA for the regional haze rulemaking. As a result, in this RIA, we calculated relatively small impacts for BART, in part because the baseline for the analysis assumed a substantial degree of emissions control for BART-eligible sources in response to the national ambient air quality standards (NAAQS) for $PM_{2.5}$.

The EPA provided a benefits analysis of the emissions reductions associated with the four illustrative progress goals in the RIA for the final rulemaking. This benefits analysis is also incremental to partial attainment of the PM and ozone NAAQS issued in 1997. We did not, however, include a benefits analysis for the reductions from controls specific to the potentially affected BART sources. For more information on the benefit analysis for the final Regional Haze rulemaking, please refer to the RIA in the public docket for the regional haze rule (Docket A–95–38).

B. Regulatory Flexibility Act

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this proposed rule. The EPA has also determined that this proposed rule would not have a significant impact on a substantial number of small entities because the rule would not establish requirements applicable to small entities.

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. No.104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. See *Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1170 (D.C.

Cir. 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC,* 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

Similar to the discussion in the proposed and final regional haze rules, the proposed BART guidelines would not establish requirements applicable to small entities. The proposed rule would apply to States, not to small entities. The BART requirements in the regional haze rule require BART determinations for a select list of major stationary sources defined by section 169A(g)(7) of the CAA. However, as noted in the proposed and final regional haze rules, the State's determination of BART for regional haze involves some State discretion in considering a number of factors set forth in section 169A(g)(2), including the costs of compliance. Further, the final regional haze rule allows States to adopt alternative measures in lieu of requiring the installation and operation of BART at these major stationary sources. As a result, the potential consequences of the BART provisions of the regional haze rule (as clarified in today's proposed guidelines) at specific sources are speculative. Any requirements for BART will be established by State rulemakings. The States would accordingly exercise substantial intervening discretion in implementing the BART requirements of the regional haze rule and today's proposed guidelines. In addition, we note that most sources potentially affected by the BART requirements in section 169A of the CAA are large industrial plants. Of these, we would expect few, if any, to be considered small entities. We request comment on issues regarding small entities that States might encounter when implementing the BART provision.

For today's proposed BART guidelines, EPA certifies that the guidelines and accompanying regulatory text would not have a significant impact on a substantial number of small entities.

C. Paperwork Reduction Act—Impact on Reporting Requirements

The information collection requirements in today's proposal clarify, but do not modify, the information collection requirements for BART. Reporting requirements related to BART requirements were included in an Information Collection Request document that was prepared by EPA (ICR No. 1813.02) and a copy may be obtained from Sandy Farmer, by mail at Collection Strategies Division; U.S. EPA (2822) 1200 Pennsylvania Avenue, NW., Washington, DC 20460, by email at *farmer.sandy@epa.gov,* or by calling (202) 260–2740. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.* The information requirements are not effective until OMB approves them.

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

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

Comments are requested on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICR to the Director, Collection Strategies Division; U.S. Environmental Protection Agency (2822); 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658 (5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

By proposing to release BART guidelines and to require their use, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan.

Further, EPA carried out consultations with the governmental entities affected by this rule in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA.

The EPA also believes that because today's proposal provides States with substantial flexibility, the proposed rule meets the UMRA requirement in section 205 to select the least costly and burdensome alternative in light of the statutory mandate for BART. The proposed rule provides States with the flexibility to establish BART based on certain criteria, one of which is the costs of compliance. The proposed rule also provides States with the flexibility to adopt alternatives, such as an emissions trading program, in lieu of requiring BART. The BART guidelines therefore, inherently provides for adoption of the least costly, most cost-effective, or least-burdensome alternative that achieves the objective of the rule.

The EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. It is questionable whether a requirement to submit a State Implementation Plan (SIP) revision constitutes a Federal mandate. The obligation for a State to revise its SIP that arises out of sections 110(a), 169A and 169B of the CAA is not legally enforceable by a court of law and, at most, is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(A)(i) of UMRA (2 U.S.C. 658 (5)(A)(i)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(A)(i)(I) of UMRA (2 U.S.C. 658(5)(A)(i)(I)). As noted earlier, however, notwithstanding these issues, the discussion in section 2 and the analysis in chapter 8 of the RIA constitutes the UMRA statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

E. Environmental Justice—Executive Order 12898

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The requirements of Executive Order 12898 have been previously addressed to the extent practicable in the RIA cited above, particularly in chapters 2 and 9 of the RIA.

F. Protection of Children From Environmental Health Risks and Safety Risks—Executive Order 13045

Executive Order 13045: ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. The BART guidelines are not subject to Executive Order 13045 because they do not establish an environmental standard intended to mitigate health or safety risks.

G. Executive Order 13132: Federalism

Executive Order 13132, entitled Federalism (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' Under Section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

The EPA concludes that this rule will not have substantial federalism implications, as specified in section 6 of Executive Order 13132 (64 FR 43255, August 10, 1999), because it will not directly impose significant new requirements on State and local governments, nor substantially alter the relationship or the distribution of power and responsibilities between States and the Federal government.

Although EPA has determined that section 6 of Executive Order 13132 does not apply, EPA nonetheless consulted with a broad range of State and local officials during the course of developing this proposed rule. These included contacts with the National Governors Association, National League of Cities, National Conference of State Legislatures, U. S. Conference of Mayors, National Association of Counties, Council of State Governments, International City/County Management Association, and National Association of Towns and Townships.

H. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

On November 6, 2000, the President issued Executive Order 13175 (65 FR 67249) entitled ''Consultation and Coordination with Indian Tribal Governments.'' Executive Order 13175 took effect on January 6, 2001, and revokes Executive Order 13084 (Tribal Consultation) as of that date. The EPA developed this proposed rule, however, during the period when EO 13084 was in effect; thus, EPA addressed tribal considerations under EO 13084. The EPA will analyze and fully comply with the requirements of EO 13175 before promulgating the final rule.

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide to OMB, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's proposed rule does not significantly or uniquely affect the communities of Indian tribal governments. This proposed action does not involve or impose any requirements that directly affect Indian tribes. Under EPA's tribal authority rule, tribes are not required to implement CAA programs but, instead, have the opportunity to do so. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Pub. L. No.

104–113, § 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

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

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.'' Under Executive Order 13211, a Statement of Energy Effects is a detailed statement by the agency responsible for the significant energy action relating to: (i) any adverse effects on energy supply, distribution, or use including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use. While this rulemaking is a ''significant regulatory action'' under Executive Order 12866, EPA has determined that this rulemaking is not a significant energy action because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

As discussed above in Unit IV.A, EPA provided an estimate of the potential cost of control to BART sources in the RIA for the regional haze rule for the year 2015. As specified in the CAA, these BART sources include certain utility steam electric plants and sources in 25 additional industrial source categories. In 1999, EPA estimated that BART would impose additional costs of $72 million per year (in 1990 dollars) in 2015 on affected utility and industrial sources.[4] It is expected that these annual costs will be lower in 2015 than currently projected due to continued improvements in scrubber operation and design. Included in the total cost is an estimate that roughly 35 utility units built between the years 1962 and 1977 would be required to install additional control equipment, typically scrubbers.

Consistent with the RIA, we have looked at the potential energy impacts associated with scrubbers. About 60 percent of the overall $72 million estimate, or about $40 million, was a result of scrubber cost calculations. These scrubber cost calculations are based on cost models which determine three types of costs for scrubbers: (1) Annualized capital costs, (2) fixed operation and maintenance costs, and (3) variable operating and maintenance costs. The cost models for variable operating and maintenance costs took into account the energy needs of the scrubber, which was assumed to be 2.0% of the electricity generated by a plant (or approximately 15,000 Megawatt-hours per year (MW–h/yr) for a 100 MW scrubber).[5] Although BART requirements may also be achieved with other control strategies and techniques (such as emission trading, or switching types of fuels used to produce power), these scrubber cost calculations can be used to provide an order of magnitude estimate of possible energy costs. The EPA estimates that of the total annual cost estimate of $40 million for scrubbers, about 20 to 35 percent, or about $9 million to $15 million, would be variable operating and maintenance costs. The energy costs for the scrubbers would be some fraction of this $9 to $15 million estimate, which also includes other elements such as the costs of reagents and disposal. Applying this energy use to the roughly 35 utility units requires a total of 525 million MW–h/yr, or 0.5 billion Kilowatt-hours/year (kWh–yr) of energy, which is valued at $17 million.[6]

The EPA also believes that an annual cost of $40 million for the electric utility sector for the year 2015 and beyond would not result in significant changes in electricity or fuel prices, or in significant changes in the consumption of energy.

For non-utility sources, the costs of the BART requirements may result from installing, operating and maintaining pollution control equipment or from other control strategies and techniques. As with utilities, a fraction of these costs in some cases would be related to the energy used to operate the pollution control equipment, thus increasing the overall demand for energy and fuels; however, such impacts are usually a small fraction of the overall annualized costs of control equipment. Thus, EPA believes that the energy costs for non-utility categories would be a relatively small fraction of the $72 million cost estimate. The EPA believes that the overall effects on energy supply and use for a small fraction of $72 million would be trivial, and that this would not significantly affect the price or supply of energy.

Therefore, we conclude that based on the analysis above that the BART requirements of the Regional Haze Rule will have a minimal impact, if any, on energy prices, or on the supply, distribution, or use of energy.

K. Guidelines for BART Determinations Under the Regional Haze Rule

We are proposing to adopt guidelines for BART determinations under the regional haze rule. The guidelines and areas on which comment is requested are described below. After we receive comments on these guidelines, we will add them to 40 CFR part 51 as appendix Y.

Guidelines for BART Determinations Under the Regional Haze Rule

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[4] *Regulatory Impact Analysis for the Regional Haze Rule.* U.S. EPA, Office of Air Quality Planning and Standards. April 22, 1999. Unit 6.6.3, pp. 6–40 through 6–42.

[5] U.S. Environmental Protection Agency, *Controlling SO2 Emissions: A Review of Technologies,* EPA–600/R–00–093, Office of Research and Development, National Risk Management Research Laboratory, Research Triangle Park, NC, October 2000, pp 32–34.

[6] Based on wholesale energy prices for the year 2000.

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I. Introduction and Overview

A. What Is the Purpose of the Guidelines?

The Clean Air Act (CAA), in sections 169A and 169B, contains requirements for the protection of visibility in 156 scenic areas across the United States. To meet the CAA's requirements, EPA recently published regulations to protect against a particular type of visibility impairment known as "regional haze." The regional haze rule is found in this part (40 CFR part 51), in §§ 51.300 through 51.309. These regulations require, in § 51.308(e), that certain types of existing stationary sources of air pollutants install best available retrofit technology (BART). The guidelines are designed to help States and others (1) identify those sources that must comply with the BART requirement, and (2) determine the level of control technology that represents BART for each source.

B. What Does the CAA Require Generally for Improving Visibility?

Section 169A of the CAA, added to the CAA by the 1977 amendments, requires States to protect and improve visibility in certain scenic areas of national importance. The scenic areas protected by section 169A are called "mandatory Class I Federal Areas." In these guidelines, we refer to these as "Class I areas." There are 156 Class I areas, including 47 national parks (under the jurisdiction of the Department of Interior—National Park Service), 108 wilderness areas (under the jurisdiction of the Department of Interior–Fish and Wildlife Service or the Department of Agriculture—US Forest Service), and one International Park (under the jurisdiction of the Roosevelt-Campobello International Commission). The Federal Agency with jurisdiction over a particular Class I area is referred to in the CAA as the Federal Land Manager. A complete list of the Class I areas is contained in 40 CFR part 81, §§ 81.401 through 81.437, and you can find a map of the Class I areas at the following internet site: *http://www.epa.gov/ttn/oarpg/t1/fr—notices/classimp.gif*

The CAA establishes a national goal of eliminating man-made visibility impairment from the Class I areas where visibility is an important value. As part of the plan for achieving this goal, the visibility protection provisions in the CAA mandate that EPA issue regulations requiring that States adopt measures in their State Implementation Plans (SIPs), including long-term strategies, to provide for reasonable progress towards this national goal. The CAA also requires States to coordinate with the Federal Land Managers as they develop their strategies for addressing visibility.

C. What Is the BART Requirement in the CAA?

Under section 169A(b)(2)(A) of the CAA, States must require certain existing stationary sources to install BART. The BART requirement applies to "major stationary sources" from one of 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires only sources which were put in place during a specific 15-year time interval to install BART. The BART requirement applies to sources that existed as of the date of the 1977 CAA amendments (that is, August 7, 1977) but which had not been in operation for more than 15 years (that is, not in operation as of August 7, 1962).

The CAA requires BART when any source meeting the above description ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility'' in any Class I area. In identifying a level of control as BART, States are required by section 169A(g) of the CAA to consider:

—The costs of compliance,
—The energy and non-air quality environmental impacts of compliance,
—Any existing pollution control technology in use at the source,
—The remaining useful life of the source, and
—The degree of visibility improvement which may reasonably be anticipated from the use of BART.

The CAA further requires States to make BART emission limitations part of their SIPs. As with any SIP revision, this will be a public process that provides an opportunity for public comment and judicial review of any decision by EPA to approve or disapprove the revision.

D. What Types of Visibility Problems Does EPA Address in Its Regulations?

The EPA addressed the problem of visibility in two phases. In 1980, EPA published regulations addressing what we termed ''reasonably attributable'' visibility impairment. Reasonably attributable visibility impairment is the result of emissions from one or a few sources that are generally located in close proximity to a specific Class I area. The regulations addressing reasonably attributable visibility impairment are published in §§ 51.300 through 51.307.

On July 1, 1999, EPA amended these regulations to address the second, more common, type of visibility impairment known as ''regional haze.'' Regional haze is the result of the collective contribution of many sources over a broad region. The regional haze rule regulations slightly modified 40 CFR 51.300 through 51.307, including the addition of a few definitions in § 51.301, and added new §§ 51.308 and 51.309.

E. What Are the BART Requirements in EPA's Regional Haze Regulations?

In the July 1, 1999 rulemaking, EPA added a BART requirement for regional haze. You will find the BART requirements in 40 CFR 51.308(e)(1). Definitions of terms used in 40 CFR 51.308(e)(1) are found in § 51.301.

As we discuss in detail in these guidelines, the regional haze rule codifies and clarifies the BART provisions in the CAA. The rule requires that States identify and list ''BART-eligible sources,'' that is, that States identify and list those sources that fall within one of 26 source categories, that were put in place during the 15-year window of time from 1962 to 1977, and that have potential emissions greater than 250 tons per year. Once the State has identified the BART-eligible sources, the next step is to identify those BART eligible sources that may ''emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility.'' Under the rule, a source which fits this description is ''subject to BART.'' For each source subject to BART, States must identify the level of control representing BART based upon the following analyses:

— First, paragraph 308(e)(1)(ii)(A) provides that States must identify the best system of continuous emission control technology for each source subject to BART taking into account the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source.
— Second, paragraph 308(e)(1)(ii)(B), provides that States must conduct an analysis of the degree of visibility improvement that would be achieved from all sources subject to BART that are within a geographic area that contributes to visibility impairment in any protected Class I area.

Once a State has identified the level of control representing BART (if any), it must establish an emission limit representing BART and must ensure compliance with that requirement no later than 5 years after EPA approves the SIP. States are allowed to establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

F. Do States Have an Alternative to Imposing Controls on Specific Facilities?

States are given the option under 40 CFR 51.308(e)(2) to adopt an alternative approach to imposing controls on a case-by-case basis for each source subject to BART. However, while States may instead adopt alternative measures, such as an emissions trading program, 40 CFR 51.308(e)(2)(i) requires States to provide a demonstration that any such alternative will achieve greater ''reasonable progress'' than would have resulted from installation of BART from all sources subject to BART. Such a demonstration must include:

— a list of all BART-eligible sources;
— an analysis of the best system of continuous emission control technology available for all sources subject to BART, taking into account the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source. Unlike the analysis for BART under 40 CFR 51.308(e)(1), which requires that these factors be considered on a case-by-case basis, States may consider these factors on a category-wide basis, as appropriate, in evaluating alternatives to BART;
— an analysis of the degree of visibility improvement that would result from the alternative program in each protected Class I area.

States must make sure that a trading program or other such measure includes all BART-eligible sources, unless a source has installed BART, or plans to install BART consistent with 51.308(e)(1).[1] A trading program also may include additional sources. 40 CFR 51.308(e)(2) also requires that States include in their SIPs details on how they would implement the emission trading program or other alternative measure. States must provide a detailed description of the program including schedules for compliance, the emissions reductions that they will require, the administrative and technical procedures for implementing the program, rules for accounting and monitoring emissions, and procedures for enforcement.

G. What Is Included in the Guidelines?

In the guidelines, we provide procedures States must use in implementing the regional haze BART requirements on a source-by-source basis, as provided in 40 CFR 51.308(e)(1). We address general topics related to development of a trading program or other alternative allowed by 40 CFR 51.308(e)(2), but we will address most of the details of guidance for trading programs in separate guidelines.

The BART analysis process, and the contents of this guidance, are as follows:

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[1] As noted in the preamble to the regional haze rule, States need not include a BART-eligible source in the trading program if the source already has installed BART-level pollution control technology and the emission limit is a federally enforceable requirement (64 FR 35742). We clarify in these guidelines that States may also elect to allow a source the option of installing BART-level controls within the 5-year period for compliance with the BART requirement [see section VI of these guidelines] rather than participating in a trading program.

–*Identification of all BART-eligible sources.* Section II of this guidance outlines a step-by-step process for identifying BART-eligible sources.
–*Identification of sources subject to BART.* As noted above, sources ''subject to BART'' are those BART-eligible sources which ''emit a pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area.'' We discuss considerations for identifying sources subject to BART in section III of the guidance.
–*Engineering analysis.* For each source subject to BART, the next step is to conduct an engineering analysis of emissions control alternatives. This step requires the identification of available, technically feasible, retrofit technologies, and for each technology identified, analysis of the cost of compliance, and the energy and non-air quality environmental impacts, taking into account the remaining useful life and existing control technology present at the source. For each source, a ''best system of continuous emission reduction'' will be selected based upon this engineering analysis. Guidelines for the engineering analysis are described in section IV of this guidance.
—*Cumulative air quality analysis.* The rule requires a cumulative analysis of the degree of visibility improvement that would be achieved in each Class I area as a result of the emissions reductions achievable from *all* sources subject to BART. The establishment of BART emission limits must take into account the cumulative impact overall from the emissions reductions from all of the source-specific ''best technologies'' identified in the engineering analysis. Considerations for this cumulative air quality analysis are discussed in section V of this guidance.
—*Emissions limits.* Considering the engineering analysis and the cumulative air quality analysis, States must establish enforceable limits, including a deadline for compliance, for each source subject to BART. Considerations related to these limits and deadlines are discussed in section VI of the guidance.
—*Considerations in establishing a trading program alternative.* General guidance on how to develop an emissions trading program alternative is contained in section VII of the guidance.

H. Who Is the Target Audience for the Guidelines?

The guidelines are written primarily for the benefit of State, local and tribal agencies to satisfy the requirements for including the BART determinations and emission limitations in their SIPs or tribal implementation plans (TIPs). Throughout the guidelines, which are written in a question and answer format, we ask questions ''How do I * * *?'' and answer with phrases ''you should * * *, you must* * *'' The ''you'' means a State, local or tribal agency conducting the analysis.[2] We recognize, however, that agencies may prefer to require source owners to assume part of the analytical burden, and that there will be differences in how the supporting information is collected and documented.

II. How To Identify BART-Eligible Sources

This section provides guidelines on how you identify BART-eligible sources. A BART-eligible source is an existing stationary source in 26 listed categories which meets criteria for startup dates and potential emissions.

A. What Are the Steps In Identifying BART-Eligible Sources?

Figure 1 shows the steps for identifying whether the source is a ''BART eligible source:''

Step 1: Identify the emission units in BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

[2] In order to account for the possibility that BART-eligible sources could go unrecognized, we recommend that you adopt requirements placing a responsibility on source owners to self-identify if they meet the criteria for BART-eligible sources.

Figure 1. How to determine whether a source is BART-eligible:

Step 1: Identify emission units in the BART categories

Does the plant contain emissions units in one or more of the 26 source categories? → No → Stop
→ Yes → Proceed to Step 2

Step 2: Identify the start-up dates of these emission units

Do any of these emissions units meet the following two tests?

In existence on August 7, 1977
AND
Began operation after August 7, 1962

→ No → Stop
→ Yes → Proceed to Step 3

Step 3: Compare the potential emissions from these emission units to the 250 ton/yr cutoff

Identify the "stationary source" that includes the emission units you identified in Step 2.

Add the current potential emissions from all the emission units identified in Steps 1 and 2 that are included within the "stationary source" boundary.

Are the potential emissions from these units 250 tons per year or more for any visibility-impairing pollutant?

→ No → Stop

→ Yes → These emissions units comprise the "BART-eligible source."

1. Step 1: Identify Emission Units in the BART Categories

The BART requirement only applies to sources in specific categories listed in the CAA. The BART requirement does not apply to sources in other source categories, regardless of their emissions. The listed categories are:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input,
(2) Coal cleaning plants (thermal dryers),
(3) Kraft pulp mills,
(4) Portland cement plants,
(5) Primary zinc smelters,
(6) Iron and steel mill plants,
(7) Primary aluminum ore reduction plants,
(8) Primary copper smelters,
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,
(10) Hydrofluoric, sulfuric, and nitric acid plants,
(11) Petroleum refineries,
(12) Lime plants,
(13) Phosphate rock processing plants,
(14) Coke oven batteries,
(15) Sulfur recovery plants,
(16) Carbon black plants (furnace process),
(17) Primary lead smelters,
(18) Fuel conversion plants,
(19) Sintering plants,

(20) Secondary metal production facilities,
(21) Chemical process plants,
(22) Fossil-fuel boilers of more than 250 million BTUs per hour heat input,
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
(24) Taconite ore processing facilities,
(25) Glass fiber processing plants, and
(26) Charcoal production facilities.

Some plant locations may have emission units from more than one category, and some emitting equipment may fit into more than one category. Examples of this situation are sulfur recovery plants at petroleum refineries, coke oven batteries and sintering plants at steel mills, and chemical process plants at refineries. For Step 1, you identify *all* of the emissions units at the plant that fit into one or more of the listed categories. You do not identify emission units in other categories.

Example: A mine is collocated with a electric steam generating unit and a coal cleaning plant. You would identify emission units associated with the electric steam generating unit and the coal cleaning plant, because they are listed categories but not the mine, because coal mining is not a listed category.

The category titles are generally clear in describing the types of equipment to be listed. Most of the category titles are very broad descriptions that encompass all emission units associated with a plant site (for example, ''petroleum refining'' and ''kraft pulp mills''). In addition, this same list of categories appears in the PSD regulations, for example in 40 CFR 52.21. States and source owners need not revisit any interpretations of the list made previously for purposes of the PSD program. We provide the following clarifications for a few of the category titles and we request comment on whether there are any additional source category titles for which EPA should provide clarification in the final guidelines:

—*''Steam electric plants of more than 250 million BTU/hr heat input.''* Because the category refers to ''plants,'' boiler capacities must be aggregated to determine whether the 250 million BTU/hr threshold is reached.

Example: Stationary source includes a steam electric plant with three 100 million BTU/hr boilers. Because the aggregate capacity exceeds 250 million BTU/hr for the ''plant,'' these boilers would be identified in Step 2.

''Steam electric plants'' includes combined cycle turbines because of their incorporation of heat recovery steam generators. Simple cycle turbines should not be considered ''steam electric plants'' because they typically do not make steam.

—*''Fossil-fuel boilers of more than 250 million BTU/hr heat input.''* The EPA proposes two options for interpreting this source category title. The first option is the approach used in the regulations for prevention of significant deterioration (PSD). In the PSD regulations, this same statutory language has been interpreted in regulatory language to mean ''fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input.'' The EPA proposes that this same interpretation be used for BART as well. Thus, as in the example above, you would aggregate boiler capacities to determine whether the 250 million BTU/hr threshold is reached.

Under the second option, this category would be interpreted to cover only those boilers that are individually greater than 250 million BTU/hr. This approach would result in differing language from the PSD program. It is possible, however, that different approaches may be justified. The PSD program ensures that new source projects do not circumvent the program by constructing several boilers with capacities lower than 250 million BTU/hr. Because the BART program affects only sources already in existence as of the date of the 1977 CAA amendments, there may be a lesser need to aggregate boilers that are individually less than 250 million BTU/hr. The EPA requests comment on both options proposed above.

—*Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels.* The 300,000 barrel cutoff refers to total facility-wide tank capacity for tanks that were put in place within the 1962–1977 time period, and includes gasoline and other petroleum-derived liquids.

—''*Phosphate rock processing plants.''* This category descriptor is broad, and includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants.

—''*Charcoal production facilities.''* In a letter sent to EPA on October 11, 2000, the National Association of Manufacturers (NAM) noted that there is some limited legislative history on this source category list. Specifically, there is discussion in the Congressional Record from July 29, 1976 (Cong. Record S. 12781–12784) which identifies a study in the 1970s by the Research Corporation of New England (the TRC report). The Congressional Record contains a table extracted from the TRC report that identifies 190 source categories considered in developing a list of 28 categories that led to the 26 categories eventually listed in the CAA. In its October 11, 2000 letter, NAM suggests that the Congressional Record and the TRC report are relevant to the interpretation of the source category ''charcoal production facilities.'' While EPA does not believe that the TRC report or table contain any information that would suggest subdividing this category, EPA has included the NAM letter and the cited passage from the Congressional Record in the docket for this proposed rule. The EPA requests comment on whether and how the information cited by NAM is relevant to the interpretation of this or other categories.

2. Step 2: Identify the Start-Up Dates of the Emission Units

Emissions units listed under Step 1 are BART-eligible only if they were ''in existence'' on August 7, 1977 but were not ''in operation'' before August 7, 1962.

What does ''in existence on August 7, 1977'' mean?

The regulation defines ''in existence'' to mean that:

> The owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. See 40 CFR 51.301.

Thus, the term ''in existence'' means the same thing as the term ''commence construction'' as that term is used in the PSD regulations. See 40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21(b)(9). Thus, an emissions unit could be ''in existence'' according to this test even if it did not begin operating until several years later.

Example: The owner or operator obtained necessary permits in early 1977 and entered into binding construction agreements in June 1977. Actual on-site construction began in late 1978, and construction was completed in mid-1979. The source began operating in September 1979. The emissions unit *was* ''in existence'' as of August 7, 1977.

We note that emissions units of this size for which construction commenced

AFTER August 7, 1977 (i.e., were not "in existence" on August 7, 1977) were subject to major new source review (NSR) under the PSD program. Thus, the August 7, 1977 "in existence" test is essentially the same thing as the identification of emissions units that were grandfathered from the NSR review requirements of the 1977 CAA amendments.

Finally, we note that sources are not BART eligible if the only change at the plant was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not by themselves trigger a BART review.

What does "in operation before August 7, 1962" mean?

An emissions unit that meets the August 7, 1977 "in existence" test is not BART-eligible if it was in operation before August 7, 1962. "In operation" is defined as "engaged in activity related to the primary design function of the source." This means that a source must have begun actual operations by August 7, 1962 to satisfy this test.

Example: The owner or operator entered into binding agreements in 1960. Actual on-site construction began in 1961, and construction was complete in mid-1962. The source began operating in September 1962. The emissions unit *was not* "in operation" before August 7, 1962 and is therefore subject to BART.

What is a "reconstructed source?"

Under a number of CAA programs, an existing source which is completely or substantially rebuilt is treated as a new source. Such "reconstructed" sources are treated as new sources as of the time of the reconstruction. Consistent with this overall approach to reconstructions, the definition of BART-eligible facility (reflected in detail in the definition of "existing stationary facility") includes consideration of sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period.

Under the regulation, a reconstruction has taken place if "the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source." The rule also states that "Any final decision as to whether reconstruction has occurred must be made in accordance with the provisions of §§ 60.15 (f)(1) through (3) of this title." [40 CFR 51.301]. "§§ 60.15(f)(1) through (3)" refers to the general provisions for New Source Performance Standards (NSPS). Thus, the same policies and procedures for identifying reconstructed "affected facilities" under the NSPS program must also be used to identify reconstructed "stationary sources" for purposes of the BART requirement.

You should identify reconstructions on an emissions unit basis, rather than on a plantwide basis. That is, you need to identify only the reconstructed emission units meeting the 50 percent cost criterion. You should include reconstructed emission units in the list of emission units you identified in Step 1.

The "in operation" and "in existence" tests apply to reconstructed sources. If an emissions unit was reconstructed and began actual operation before August 7, 1962, it is not BART-eligible. Similarly, any emissions unit for which a reconstruction "commenced" after August 7, 1977, is not BART-eligible.

How are modifications treated under the BART provision?

The NSPS program and the major source NSR program both contain the concept of modifications. In general, the term "modification" refers to any physical change or change in the method of operation of an emissions unit that leads to an increase in emissions.

The BART provision in the regional haze rule contains no explicit treatment of modifications. Accordingly, guidelines are needed on how modified emissions units, previously subject to best available control technology (BACT), lowest achievable emission rate (LAER) and/or NSPS, are treated under the rule. The EPA believes that the best interpretation for purposes of the visibility provisions is that modified emissions units are still "existing." The BART requirements in the CAA do not appear to provide any exemption for sources which were modified since 1977. Accordingly, if an emissions unit began operation before 1962, it is not BART-eligible if it is modified at a later date, so long as the modification is not also a "reconstruction." Similarly, an emissions unit which began operation within the 1962–1977 time window, but was modified after August 7, 1977, is BART-eligible. We note, however, that if such a modification was a major modification subject to the BACT, LAER, or NSPS levels of control, the review process will take into account that this level of control is already in place and may find that the level of controls are already consistent with BART. The EPA requests comment on this interpretation for "modifications." [3]

3. Step 3: Compare the potential emissions to the 250 ton/yr cutoff

The result of Steps 1 and 2 will be a list of emissions units at a given plant site, including reconstructed emissions units, that are within one or more of the BART categories and that were placed into operation within the 1962–1977 time window. The third step is to determine whether the total emissions represent a current potential to emit that is greater than 250 tons per year of any single visibility impairing pollutant. In most cases, you will add the potential emissions from all emission units on the list resulting from Steps 1 and 2. In a few cases, you may need to determine whether the plant contains more than one "stationary source" as the regional haze rule defines that term, and as we explain further below.

What pollutants should I address?

Visibility-impairing pollutants include the following:

—Sulfur dioxide (SO_2),
—Nitrogen oxides (NO_X),
—Particulate matter. (You may use PM_{10} as the indicator for particulate matter. We do not recommend use of total suspended particulates (TSP). PM_{10} emissions include the components of $PM_{2.5}$ as a subset. There is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$, because 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5}$, and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc).
—Volatile organic compounds (VOC), and
—Ammonia.

What does the term "potential" emissions mean?

The regional haze rule defines potential to emit as follows:

"Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

[3] Another possible interpretation would be to consider sources built before 1962 but modified during the 1962–1977 time window as a "new" source at the time of the modification. Under this approach, such sources would be considered to have commenced operation during the 1962–1977 time period, and thus would be BART eligible. Similarly, consistent with this interpretation, a source modified after the 1977 date would be treated as "new" as of the date of the modification and therefore would not be BART-eligible. The EPA believes that this approach may be much more difficult to implement, given that programs to identify "modifications" were not in place for much of the 1962–1977 time period.

This definition is identical to that in the PSD program (40 CFR 51.166 and 51.18). This means that a source which actually emits less than 250 tons per year of a visibility-impairing pollutant is BART-eligible if its emissions would exceed 250 tons per year when operating at its maximum physical and operational design.

Example: A source, while operating at one-fourth of its capacity, emits 75 tons per year of SO_2. If it were operating at 100 percent of its maximum capacity, the source would emit 300 tons per year. Because under the above definition such a source would have ''potential'' emissions that exceed 250 tons per year, the source (if in a listed category and built during the 1962–1977 time window) would be BART-eligible.

A source's ''potential to emit'' may take into account federally enforceable emission limits.

Example: The same source has a federally enforceable restriction limiting it to operating no more than ½ of the year. Because you can credit this under the definition of potential to emit, the source would have a potential of 150 tons per year, which is less than the 250 tons/year cutoff.

The definition of potential to emit allows only federally enforceable emission limits to be taken into account for this purpose, and does not credit emission limitations which are enforceable only by State and local agencies, but not by EPA and citizens in Federal court. As a result of some court cases in other CAA programs, EPA is undertaking a rulemaking to determine whether only federally enforceable limits should be taken into account. This rulemaking will address the Federal enforceability restriction in the regional haze definition as well as other program definitions. We expect that this rulemaking will be complete well before the time period for determining whether BART applies.

How do I identify whether a plant has more than one ''stationary source?''

The regional haze rule, in 40 CFR 51.301, defines a stationary source as a ''building, structure, facility or installation which emits or may emit any air pollutant.'' [4] The rule further defines ''building, structure or facility'' as:

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

In applying this definition, it is first necessary to draw the plant boundary, that is the boundary for the ''contiguous or adjacent properties.'' Next, within this plant boundary it is necessary to group those emission units that are under ''common control.'' The EPA notes that these plant boundary issues and ''common control'' issues are very similar to those already addressed in implementation of the title V operating permits program and in NSR.

For emission units within the ''contiguous or adjacent'' boundary and under common control, you then group emission units that are within the same industrial grouping (that is, associated with the same 2-digit Standard Industrial Classification (SIC) code).[5] For most plants on the BART source category list, there will only be one 2-digit SIC that applies to the entire plant. For example, all emission units associated with kraft pulp mills are within SIC code 26, and chemical process plants will generally include emission units that are all within SIC code 28. You should apply this ''2-digit SIC test'' the same way you are now applying this test in the major source NSR programs.[6]

For purposes of the regional haze rule, you group emissions from all emission units put in place within the 1962–1977 time period that are within the 2-digit SIC code, even if those emission units are in different categories on the BART category list.

Examples: A chemical plant which started operations within the 1962 to 1977 time period manufactures hydrochloric acid (within the category title ''Hydrochloric, sulfuric, and nitric acid plants'') and various organic chemicals (within the category title ''chemical process plants''), and has onsite an industrial boiler greater than 250 million BTU/hour. All of the emission units are within SIC 28 and, therefore, all the emission units are considered in determining BART eligibility of the plant. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

A steel mill which started operations within the 1962 to 1977 time period includes a sintering plant, a coke oven battery, and various other emission units. All of the emission units are within SIC 33. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

4. Final Step: Identify the Emissions Units and Pollutants That Constitute the BART-Eligible Source

If the emissions from the list of emissions units at a stationary source exceed a potential to emit of 250 tons per year for any visibility-impairing pollutant, then that collection of emissions units is a BART-eligible source. A BART analysis is required for each visibility-impairing pollutant emitted.

Example: A stationary source comprises the following two emissions units, with the following potential emissions:

Emissions unit A
500 tons/yr SO_2
150 tons/yr NO_X
25 tons/yr PM
Emissions unit B
100 tons/yr SO_2
75 tons/yr NO_X
10 tons/yr PM

For this example, potential emissions of SO_2 are 600 tons per year, which exceeds the 250 tons/yr threshold. Accordingly, the entire ''stationary source'' that is emissions units A and B are subject to a BART review for SO_2, NO_X, and PM, even though the potential emissions of PM and NO_X each are less than 250 tons/yr.

Example: The total potential emissions, obtained by adding the potential emissions of all emission units in listed categories at a plant site, are as follows:

200 tons/yr SO_2
150 tons/yr NO_X
25 tons/yr PM

Even though total emissions exceed 250 tons per year, no individual regulated pollutant exceeds 250 tons per year and this source is not BART-eligible.

III. How To Identify Sources ''Subject To BART''

After you have identified the BART-eligible sources, the next step is determining whether these sources are subject to a further BART analysis because they emit ''an air pollutant which may reasonably be anticipated to cause or contribute'' to any visibility

[4] **Note:** Most of these terms and definitions are the same for regional haze and the 1980 visibility regulations. For the regional haze rule we use the term ''BART-eligible source'' rather than ''existing stationary facility'' to clarify that only a limited subset of existing stationary sources are subject to BART.

[5] The EPA recognizes that we are in transition period from the use of the SIC system to a new system called the North American industry Classification System (NAICS). Our initial thinking is that BART determinations, as a one-time activity, are perhaps best handled under the SIC classifications. We request comment on whether a switch to the new system for the regional haze rule is warranted—we expect that few if any BART eligibility determinations would hinge on this distinction.

[6] **Note:** The concept of support facility used for the PSD program applies here as well. As discussed in the draft *New Source Review Workbook Manual,* October 1990, pages A.3–A.5, support facilities, that is facilities that convey, store or otherwise assist in the production of the principal product, must be grouped with primary facilities even when more than one 2-digit SIC is present.

impairment in a Federal Class I area. As we discuss in the preamble to the regional haze rule at 64 FR 35739–35740, the statutory language represents a very low triggering threshold. In implementing the regional haze rule, you should find that a BART-eligible source is ''reasonably anticipated to cause or contribute'' to regional haze if the source emits pollutants within a geographic region from which pollutants can be emitted and transported downwind to a Class I area. Where emissions from a given geographic region contribute to regional haze in a Class I area, you should consider any emissions from BART-eligible sources in that region to contribute to the regional haze problem, thereby warranting a further BART analysis for those sources.

A. How Can I Identify ''the Geographic Area'' or ''Region'' That Contributes to a Given Class I Area?

As noted in the preamble to the regional haze rule, geographic ''regions'' that can contribute to regional haze generally extend for hundreds or thousands of kilometers (64 FR 35722). Accordingly, most BART-eligible sources are located within such a geographic region. For example, we believe it would be difficult to demonstrate that a State or territory's emissions do not contribute to regional haze impairment in a Class I area within that State or territory.

The regional haze rule recognizes that there may be geographic areas (individual States or multi-State areas) within the United States, (in virtually all cases involving States that do not have Class I areas) for which the total emissions make only a trivial contribution to visibility impairment in any Class I area. In identifying any such State or area, you or a regional planning organization must conduct an air quality modeling analysis to demonstrate that the total emissions from the State or area makes only a trivial contribution to visibility impairment in Class I areas.

One approach that can be used is to determine whether a State or area contributes in a non-trivial way would be to do an analysis where you compare the visibility impairment in a Class I area with the emissions from a State or area to the visibility impairment in the Class I area in the absence of the emissions from the State or area. This approach can be referred to as a ''zero-out'' approach where you zero out the emissions from the State or area that is suspected to make a trivial contribution to visibility impairment in a Class I area. Under this approach, you would compare:

(1) the visibility impairment in each affected Class I area (for the average of the 20 percent most impaired days and the 20 percent least impaired days) when the emissions from the State or area suspected to have a trivial contribution are included in the modeling analysis, and

(2) the visibility impairment in each affected Class I area (for the average of the 20 percent most impaired days and the 20 percent least impaired days), excluding from the modeling analysis the emissions from the geographic area suspected to have a trivial impact.

The difference in visibility between these two model runs provides an indication of the impact on visibility of emissions from the State(s) in question. In addition, it may be possible in the future to conduct analyses of the geographic area that contributes to visibility impairment in a Class I area through use of a source apportionment model for PM. Source apportionment models for PM are currently under development by private consultants. Guidance for regional modeling for visibility and PM is found in a document entitled ''Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze.'' [**Note:** this document is currently in draft form, but we expect a final document before final publication of the BART guidelines]

IV. Engineering Analysis of BART Options

This section describes the process for the engineering analysis of control options for sources subject to BART.

A. What Factors Must I Address in the Engineering Analysis?

The visibility regulations define BART as follows:

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by * * * [a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

In the regional haze rule, we divide the BART analysis into two parts: an engineering analysis requirement in 40 CFR 51.308(e)(1)(ii)(A), and a visibility impacts analysis requirement in 40 CFR 51.308(e)(1)(ii)(B). This section of the guidelines address the requirements for the engineering analysis. Your engineering analysis identifies the best system of continuous emission reduction taking into account:

—The available retrofit control options,
—Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
—The costs of compliance with control options,
—The remaining useful life of the facility (which as we will discuss below, is an integral part of the cost analysis), and
—The energy and non-air quality environmental impacts of control options.

We discuss the requirement for a visibility impacts analysis below in section V.

B. How Does a BART Engineering Analysis Compare to a BACT Review Under the PSD Program?

In this proposal, we are seeking comment on two alternative approaches for conducting a BART engineering analysis. EPA prefers the first approach. Under this first alternative, the BART analysis would be very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis would be a process which provides that all available control technologies be ranked in descending order of control effectiveness. Under this option, you must first examine the most stringent alternative. That alternative is selected as the ''best'' unless you demonstrate and document that the alternative cannot be justified based upon technical considerations, costs, energy impacts, and non-air quality environmental impacts. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.

The EPA also requests comment on an alternative decision-making approach that would not necessarily begin with an evaluation of the most stringent control option. Under this approach, you would have more choices in the way you structure your BART analysis. For example, you could choose to begin the BART determination process by evaluating the least stringent technically feasible control option or an intermediate control option drawn from the range of technically feasible control alternatives. Under this approach, you would then consider the additional emission reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, you would still be required to (1) display and rank all of the options in order of control effectiveness, including the most stringent control option, and to identify the average and incremental costs of each option; (2) consider the energy and non-air quality environmental impacts of each option; and (3) provide a justification for adopting the control technology that you select as the ''best'' level of control, including an explanation as to why you rejected other more stringent control technologies. While both approaches require essentially the same parameters and analyses, the EPA prefers the first approach described above, because we believe it may be more straightforward to implement than the alternative and would tend to give more thorough consideration to stringent control alternatives.

Although very similar in process, BART reviews differ in several respects from the BACT review process described in the NSR Draft Manual. First, because all BART reviews apply to existing sources, the available controls and the impacts of those controls may differ. Second, the CAA requires you to take slightly different factors into account in determining BART and BACT. In a BACT analysis, the permitting authority must consider the ''energy, environmental and economic impacts and other costs'' associated with a control technology in making its determination. In a BART analysis, on the other hand, the State must take into account the ''cost of compliance, the remaining useful life of the source, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility from the use of such technology'' in making its BART determination. Because of the differences in terminology, the BACT review process tends to encompass a broader range of factors. For example, the term ''environmental impacts'' in the BACT definition is more broad than the term ''nonair quality environmental impacts'' used in the BART definition. Accordingly, there is no requirement in the BART engineering analysis to evaluate adverse air quality impacts of control alternatives such as the relative impacts on hazardous air pollutants, although you may wish to do so. Finally, for the BART analysis, there is no minimum level of control required, while any BACT emission limitation must be at least as stringent as any NSPS that applies to the source.

C. Which Pollutants Must I Address in the Engineering Review?

Once you determine that a source is subject to BART, then a BART review is required for each visibility-impairing pollutant emitted. In a BART review, for each affected emission unit, you must establish BART for each pollutant that can impair visibility. Consequently, the BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review.

Example: Plantwide emissions from emission units within the listed categories that began operation within the ''time window'' for BART [7] are 300 tons per year of NO_X, 200 tons per year of SO_2, and 150 tons of primary particulate. Emissions unit A emits 200 tons per year of NO_X, 100 tons per year of SO_2, and 100 tons per year of primary particulate. Other emission units, units B through H, which began operating in 1966, contribute lesser amounts of each pollutant. For this example, a BART review is required for NO_X, SO_2, and primary particulate, and control options must be analyzed for units B through H as well as unit A.

D. What Are the Five Basic Steps of a Case-by-Case BART Engineering Analysis?

The five steps are:

Step 1—Identify all [8] available retrofit control technologies,
Step 2—Eliminate Technically Infeasible Options,
Step 3—Rank Remaining Control Technologies By Control Effectiveness,
Step 4—Evaluate Impacts and Document the Results, and
Step 5—Select ''Best System of Continuous Emission Reduction.''

1. Step 1: How Do I Identify All Available Retrofit Emission Control Techniques?

Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant. Available air pollution control technologies can include technologies employed outside of the United States that have been successfully demonstrated in practice on full scale operations, particularly those that have been demonstrated as retrofits to existing sources. Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives. The control alternatives should include not only existing controls for the source category in question, but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice.

Where a NSPS exists for a source category (which is the case for most of the categories affected by BART), you should include a level of control equivalent to the NSPS as one of the control options.[9] The NSPS standards are codified in 40 CFR part 60. We note that there are situations where NSPS standards do not require the most stringent level of available control for all sources within a category. For example, post-combustion NO_X controls (the most stringent controls for stationary gas turbines) are not required under subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BART selection process.

Potentially applicable retrofit control alternatives can be categorized in three ways.

- Pollution prevention: use of inherently lower-emitting processes/practices, including the use of materials and production processes and work practices that prevent emissions and result in lower ''production-specific'' emissions,
- Use of, (and where already in place, improvement in the performance of) add-on controls, such as scrubbers,

[7] That is, emission uunits that were in existence on August 7, 1977 and which began actual operation on or after August 7, 1962.

[8] In identifying ''all'' options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.

[9] In EPA's 1980 BART guidelines for reasonably attributable visibility impairment, we concluded that NSPS standards generally, at that time, represented the best level sources could install as BART, and we required no further demonstration if a NSPS level was selected. In the 20 year period since this guidance was developed, there have been advances in SO_2 control technologies, confirmed by a number of recent retrofits at Western power plants. Accordingly, EPA no longer concludes that the NSPS level of controls automatically represents ''the best these sources can install.'' While it is possible that a detailed analysis of the BART factors could result in the selection of a NSPS level of control, we believe that you should only reach this conclusion based upon an analysis of the full range of control options.

fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced, and

- Combinations of inherently lower-emitting processes and add-on controls. Example: for a gas-fired turbine, a combination of combustion controls (an inherently lower-emitting process) and post-combustion controls such as selective catalytic reduction (add-on) may be available to reduce NO_X emissions.

For the engineering analysis, you should consider potentially applicable control techniques from all three categories. You should consider lower-polluting processes based on demonstrations from facilities manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BART review.

In the course of the BART engineering analysis, one or more of the available control options may be eliminated from consideration because they are demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, you should initially identify all control options with potential application to the emissions unit under review.

We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis.

In some cases, retrofit design changes may be available for making a given production process or emissions unit inherently less polluting.[10] (Example: To allow for use of natural gas rather than oil for startup). In such cases, the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls could possibly yield more effective means of emissions control than either approach alone. Therefore, the option to use an inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need to be included in the BART analysis. These combinations should be identified in Step 1 for evaluation in subsequent steps.

For emission units subject to a BART engineering review, there will often be control measures or devices already in place. For such emission units, it is important to include control options that involve improvements to existing controls, and not to limit the control options only to those measures that involve a complete replacement of control devices.

Example: For a power plant with an existing wet scrubber, the current control efficiency is 66 percent. Part of the reason for the relatively low control efficiency is that 22 percent of the gas stream bypasses the scrubber. An engineering review identifies options for improving the performance of the wet scrubber by redesigning the internal components of the scrubber and by eliminating or reducing the percentage of the gas stream that bypasses the scrubber. Four control options are identified: (1) 78 percent control based upon improved scrubber performance while maintaining the 22 percent bypass, (2) 83 percent control based upon improved scrubber performance while reducing the bypass to 15 percent, (3) 93 percent control based upon improving the scrubber performance while eliminating the bypass entirely, (this option results in a ''wet stack'' operation in which the gas leaving the stack is saturated with water) and (4) 93 percent as in option 3, with the addition of an indirect reheat system to reheat the stack gas above the saturation temperature. You must consider each of these four options in a BART analysis for this source.

You are expected to identify all demonstrated and potentially applicable retrofit control technology alternatives. Examples of general information sources to consider include:

- The EPA's Clean Air Technology Center, which includes the RACT/BACT/LAER Clearinghouse (RBLC);
- State and Local Best Available Control Technology Guidelines—many agencies have online information—for example South Coast Air Quality Management District, Bay Area Air Quality Management District, and Texas Natural Resources Conservation Commission;
- Control technology vendors;
- Federal/State/Local NSR permits and associated inspection/performance test reports;
- Environmental consultants;
- Technical journals, reports and newsletters, air pollution control seminars; and
- EPA's NSR bulletin board—http://www.epa.gov/ttn/nsr;
- Department of Energy's Clean Coal Program—technical reports;
- NO_X Control Technology ''Cost Tool''—Clean Air Markets Division web page—http://www.epa.gov/acidrain/nox/noxtech.htm;
- Performance of selective catalytic reduction on coal-fired steam generating units—final report. OAR/ARD, June 1997 (also available at http:www.epa.gov/acidrain/nox/noxtech.htm);
- Cost estimates for selected applications of NO_X control technologies on stationary combustion boilers. OAR/ARD June 1997. (Docket for NO_X SIP call, A–96–56, II–A–03);
- Investigation of performance and cost of NO_X controls as applied to group 2 boilers. OAR/ARD, August 1996. (Docket for Phase II NO_X rule, A–95–28, IV–A–4);
- Controlling SO_2 Emissions: A Review of Technologies. EPA–600/R–00–093, USEPA/ORD/NRMRL, October 2000.
- OAQPS Control Cost Manual.

You should compile appropriate information from all available information sources, and you should ensure that the resulting list of control alternatives is complete and comprehensive.

2. Step 2: How Do I Determine Whether the Options Identified in Step 1 Are Technically Feasible?

In Step two, you evaluate the technical feasibility of the control options you identified in Step one. You should clearly document a demonstration of technical infeasibility and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. You may then eliminate such technically infeasible control options from further consideration in the BART analysis.

In general, what do we mean by technical feasibility?

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: ''availability'' and ''applicability.'' As explained in more detail below, a technology is considered ''available'' if

[10] Because BART applies to existing sources, we recognize that there will probably be far fewer opportunities to consider inherently lower-emitting processes than for NSR.

the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

What do we mean by ''available'' technology?

The typical stages for bringing a control technology concept to reality as a commercial product are:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as ''available'' for purposes of BART review.

Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or ''applicable'' to the source type under consideration.

Because a new technology may become available at various points in time during the BART analysis process, we believe that guidelines are needed on when a technology must be considered. For example, a technology may become available during the public comment period on the State's rule development process. Likewise, it is possible that new technologies may become available after the close of the State's public comment period and before submittal of the SIP to EPA, or during EPA's review process on the SIP submittal. In order to provide certainty in the process, we propose that all technologies be considered if available before the close of the State's public comment period. You need not consider technologies that become available after this date. As part of your analysis, you should consider any technologies brought to your attention in public comments. If you disagree with public comments asserting that the technology is available, you should provide an explanation for the public record as to the basis for your conclusion.

What do we mean by ''applicable'' technology?

You need to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on a new or existing source with similar gas stream characteristics is generally a sufficient basis for concluding the technology is technically feasible barring a demonstration to the contrary as described below.

What type of demonstration is required if I conclude that an option is not technically feasible?

Where you assert that a control option identified in Step 1 is technically infeasible, you should make a factual demonstration that the option is commercially unavailable, or that unusual circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, or operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, you should consider the technology to be technically feasible. The cost of a control alternative is considered later in the process.

The determination of technical feasibility is sometimes influenced by recent air quality permits. In some cases, an air quality permit may require a certain level of control, but the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit). Where this is the case, you should provide supporting documentation showing why such limits are not technically feasible, and, therefore, why the level of control (but not necessarily the technology) may be eliminated from further consideration. However, if there is a permit requiring the application of a certain technology or emission limit to be achieved for such technology (especially as a retrofit for an existing emission unit), this usually is sufficient justification for you to assume the technical feasibility of that technology or emission limit.

Physical modifications needed to resolve technical obstacles do not, in and of themselves, provide a justification for eliminating the control technique on the basis of technical infeasibility. However, you may consider the cost of such modifications in estimating costs. This, in turn, may form the basis for eliminating a control technology (see later discussion).

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, you should make decisions about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees.

A possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, you should use judgment in deciding on those alternatives for which you will conduct the detailed impacts analysis (Step 4 below). For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, you may evaluate only the less costly of these options. You should narrow the scope of the BART analysis in this way, only if there is a negligible difference in emissions and energy and non-air quality environmental impacts between control alternatives.

3. Step 3: How Do I Develop a Ranking of the Technically Feasible Alternatives?

Step 3 involves ranking all the technically feasible control alternatives identified in Step 2. For the pollutant and emissions unit under review, you rank the control alternatives from the most to the least effective in terms of emission reduction potential.

Two key issues that must be addressed in this process include:

(1) Making sure that you express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and

(2) Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

In some instances, a control technology may reduce more than one visibility impairing pollutant. We request comment on whether and how the BART guidelines should address the process for ranking such control technologies against control technologies which reduce emissions of only one pollutant.

What are the appropriate metrics for comparison?

This issue is especially important when you compare inherently lower-polluting processes to one another or to add-on controls. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed.

Examples of common metrics:

• Pounds of SO_2 emissions per million Btu heat input, and

• Pounds of NO_X emissions per ton of cement produced.

How do I evaluate control techniques with a wide range of emission performance levels?

Many control techniques, including both add-on controls and inherently lower polluting processes, can perform at a wide range of levels. Scrubbers and high and low efficiency electrostatic precipitators (ESPs) are two of the many examples of such control techniques that can perform at a wide range of levels. It is not our intent to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should use the most recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) to identify an emissions performance level or levels to evaluate.

In assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you must document the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.

You may encounter cases where you may wish to evaluate other levels of control in addition to the most stringent level for a given device. While you must consider the most stringent level as one of the control options, you may consider less stringent levels of control as additional options. This would be useful, particularly in cases where the selection of additional options would have widely varying costs and other impacts.

Finally, we note that for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devices, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device.

How do I rank the control options?

After determining the emissions performance levels (using appropriate metrics of comparison) for each control technology option identified in Step 2, you establish a list that identifies the most stringent control technology option. Each other control option is then placed after this alternative in a ranking according to its respective emissions performance level, ranked from lowest emissions to highest emissions (most effective to least stringent effective emissions control alternative). You should do this for each pollutant and for each emissions unit (or grouping of similar units) subject to a BART analysis.

4. Step 4: For a BART Engineering Analysis, What Impacts Must I Calculate and Report? What Methods Does EPA Recommend for the Impacts Analysis?

After you identify and rank the available and technically feasible control technology options, you must then conduct three types of impacts analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance, (taking into account the remaining useful life of the facility)

Impact analysis part 2: Energy impacts, and

Impact analysis part 3: Non-air quality environmental impacts.

In this section, we describe how to conduct each of these three analyses. You are responsible for presenting an evaluation of each impact along with appropriate supporting information. You should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternative.

a. *Impact analysis part 1: How do I estimate the costs of control?* To conduct a cost analysis, you:

—Identify the emissions units being controlled,

—Identify design parameters for emission controls, and

—Develop cost estimates based upon those design parameters.

It is important to identify clearly the emission units being controlled, that is, to specify a well-defined area or process segment within the plant. In some cases, multiple emission units can be controlled jointly. However, in other cases it may be appropriate in the cost analysis to consider whether multiple units will be required to install separate and/or different control devices. The engineering analysis should provide a clear summary list of equipment and the associated control costs. Inadequate documentation of the equipment whose emissions are being controlled is a potential cause for confusion in comparison of costs of the same controls applied to similar sources.

You then specify the control system design parameters. Potential sources of these design parameters include equipment vendors, background information documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, control data in trade publications, and engineering and performance test data. The following are a few examples of design parameters for two example control measures:

Control device	Examples of design parameters
Wet Scrubbers	Type of sorbent used (lime, limestone, etc.) Gas pressure drop Liquid/gas ratio.

Control device	Examples of design parameters
Selective Catalytic Reduction.	Ammonia to NO_X molar ratio Pressure drop Catalyst life.

The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated. You should include in your analysis, documentation of your assumptions regarding design parameters. Examples of supporting references would include the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (see below) and background information documents used for NSPS and hazardous pollutant emission standards. If the design parameters you specified differ from typical designs, you should document the difference by supplying performance test data for the control technology in question applied to the same source or a similar source.

Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the *OAQPS Control Cost Manual,* Fifth Edition, February 1996, EPA 453/B–96–001).[11] In order to maintain and improve consistency, we recommend that you estimate control equipment costs based on the EPA/OAQPS *Control Cost Manual,* where possible.[12] The *Control Cost Manual* addresses most control technologies in sufficient detail for a BART analysis. While the types of site-specific analyses contained in the *Control Cost Manual* are less precise than those based upon a detailed engineering design, normally the estimates provide results that are plus or minus 30 percent, which is generally sufficient for the BART review. The cost analysis should take into account site-specific conditions that are out of the ordinary (e.g., use of a more expensive fuel or additional waste disposal costs) that may affect the cost of a particular BART technology option.

b. *How do I take into account a project's ''remaining useful life'' in calculating control costs?* You treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

For purposes of these guidelines, the remaining useful life is the difference between:

(1) January 1 of the year you are conducting the BART analysis (but not later than January 1, 2008); [13] and

(2) The date the facility stops operations. This date must be assured by a federally-enforceable restriction preventing further operation. A projected closure date, without such a federally-enforceable restriction, is not sufficient. (The EPA recognizes that there may be situations where a source operator intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event, for example, that market conditions change.) We request comment on how such flexibility could be provided in this regard while maintaining consistency with the statutory requirement to install BART within 5 years. For example, one option that we request comment on is allowing a source to choose between:

(1) Accepting a federally enforceable condition requiring the source to shut down by a given date, or

(2) Installing the level of controls that would have been considered BART if the BART analysis had not assumed a reduced remaining useful life if the source is in operation 5 years after the date EPA approves the relevant SIP. The source would not be allowed to operate after the 5-year mark without such controls.

c. *What do we mean by cost effectiveness?* Cost effectiveness, in general, is a criterion used to assess the potential for achieving an objective at least cost. For purposes of air pollutant analysis, ''effectiveness'' is measured in terms of tons of pollutant emissions removed, and ''cost'' is measured in terms of annualized control costs. We recommend two types of cost-effectiveness calculations—average cost effectiveness, and incremental cost-effectiveness.

In the cost analysis, you should take care to not focus on incomplete results or partial calculations. For example, large capital costs for a control option alone would not preclude selection of a control measure if large emissions reductions are projected. In such a case, low or reasonable cost effectiveness numbers may validate the option as an appropriate BART alternative irrespective of the large capital costs. Similarly, projects with relatively low capital costs may not be cost effective if there are few emissions reduced.

d. *How do I calculate average cost effectiveness?* Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:

$$\begin{array}{c}\text{Average cost effectiveness}\\ \text{(dollars per ton removed)}\end{array} = \frac{\text{Control option annualized cost}^{14}}{\text{Baseline annual emissions} - \text{Annual emissions with Control option}}$$

[11] The *Control Cost Manual* is updated periodically. While this citation refers to the latest version at the time this guidance was written, you should use the version that is current as of when you conduct your impact analysis. This document is available at the following Web site: *http://www.epa.gov/ttn/catc/dir1/chpt2acr.pdf.*

[12] You should include documentation for any additional information you used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual.*

[13] The reason for the year 2008 is that the year 2008 is the latest year for which SIPs are due to address the BART requirement.

[14] Whenever you calculate or report annual costs, you should indicate the year for which the costs are estimated. For example, if you use the year 2000 as the basis for cost comparisons, you would report that an annualized cost of $20 million would be: $20 million (year 2000 dollars).

Because you calculate costs in (annualized) dollars per year ($/yr) and because you calculate emissions rates in tons per year (tons/yr), the result is an average cost-effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

e. *How do I calculate baseline emissions?* The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. For purposes of estimating actual emissions, these guidelines take a similar approach to the current definition of actual emissions in NSR programs. That is, the baseline emissions are the average annual emissions from the two most recent years, unless you demonstrate that another period is more representative of normal source operations.[15]

When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Examples: The baseline emissions calculation for an emergency standby generator may consider the fact that the source owner would not operate more than past practice of 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine should be based on its past practice which would indicate a large number of hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost-effective controls. As a consequence of the dissimilar baseline emissions, BART for the two cases could be very different.

[15] This is the approach in the current NSR regulations. It is possible that this definition of baseline period may change based upon a current effort to amend the NSR regulations. We propose that these guidelines should be amended to be consistent with the approach taken in that separate rulemaking.

f. *How do I calculate incremental cost effectiveness?* In addition to the average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) =
(Total annualized costs of control option) − (Total annualized costs of next control option) ÷
(Next control option annual emissions) − (Control option annual emissions)

Example 1: Assume that Option F on Figure 2 has total annualized costs of $1 million to reduce 2000 tons of a pollutant, and that Option D on Figure 2 has total annualized costs of $500,000 to reduce 1000 tons of the same pollutant. The incremental cost effectiveness of Option F relative to Option D is ($1 million − $500,000) divided by (2000 tons − 1000 tons), or $500,000 divided by 1000 tons, which is $500/ton.

Example 2: Assume that two control options exist: Option 1 and Option 2. Option 1 achieves a 100,000 ton/yr reduction at an annual cost of $19 million. Option 2 achieves a 98,000 tons/yr reduction at an annual cost of $15 million. The incremental cost effectiveness of Option 1 relative to Option 2 is ($19 million − $15 million) divided by (100,000 tons − 98,000 tons). The adoption of Option 1 instead of Option 2 results in an incremental emission reduction of 2,000 tons per year at an additional cost of $4,000,000 per year. The incremental cost of Option 1, then, is $2000 per ton − 10 times the average cost of $190 per ton. While $2000 per ton may still be deemed reasonable, it is useful to consider both the average and incremental cost in making an overall cost-effectiveness finding. Of course, there may be other differences between these options, such as, energy or water use, or non-air environmental effects, which also deserve consideration in selecting a BART technology.

You should exercise care in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between ‘‘dominant’’ alternatives. To identify dominant alternatives, you generate a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BART analysis, and by identifying a ‘‘least-cost envelope’’ as shown in Figure 2.

Example: Eight technically feasible control options for analysis are listed in the BART ranking. These are represented as A through H in Figure 2. The dominant set of control options, B, D, F, G, and H, represent the least-cost envelope, as we depict by the cost curve connecting them. Points A, C and E are inferior options, and you should not use them in calculating incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reductions for less money than A; and similarly, D and F will buy more reductions for less money than C and E, respectively.

In calculating incremental costs, you:

(1) Rank the control options in ascending order of annualized total costs,

(2) Develop a graph of the most reasonable smooth curve of the control options, as shown in Figure 2, and

(3) Calculate the incremental cost effectiveness for each dominant option, which is the difference in total annual costs between that option and the next most stringent option, divided by the difference in emissions reductions between those two options. For example, using Figure 2, you would calculate incremental cost effectiveness for the difference between options B and D, options D and F, options F and G, and options G and H.

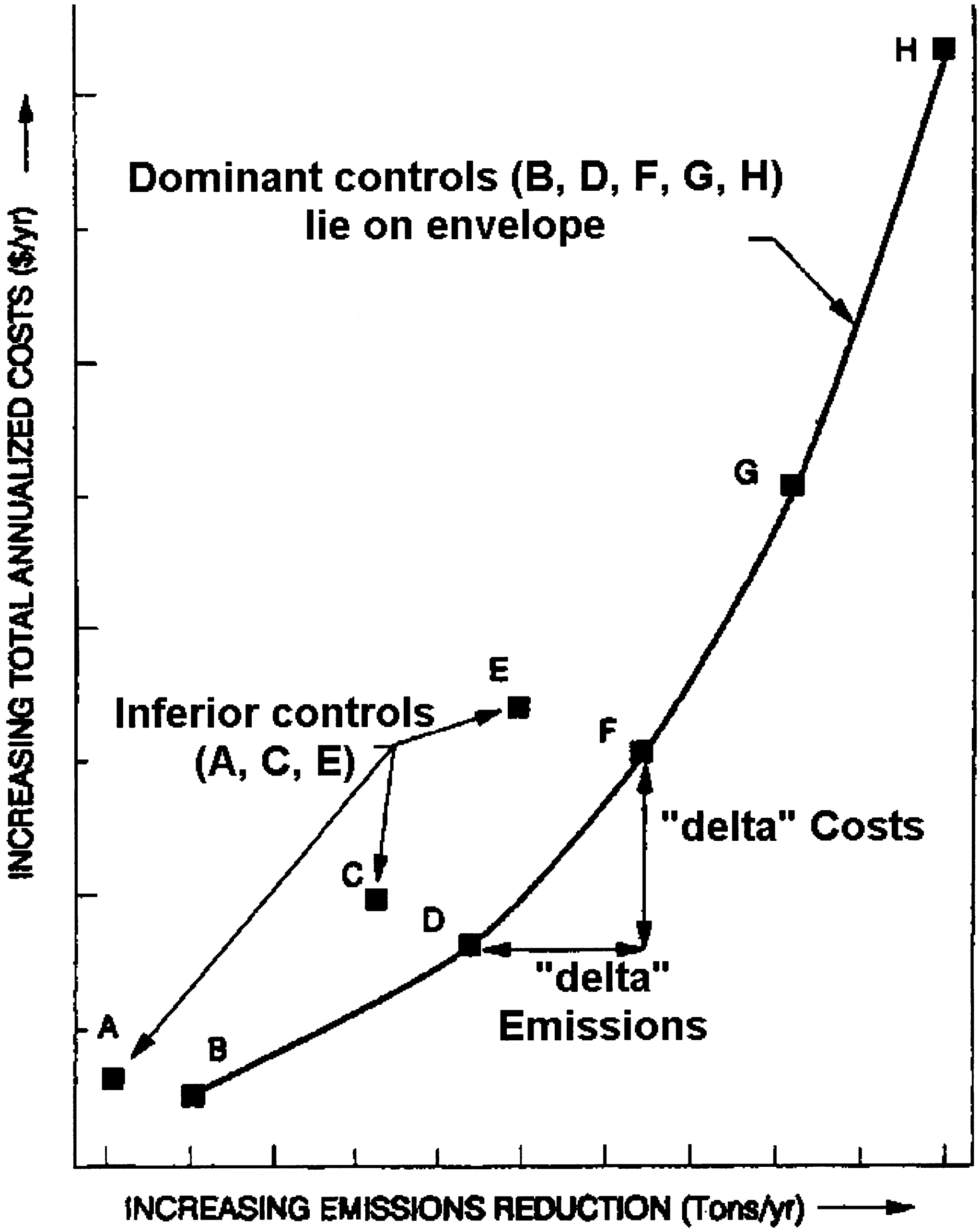

Figure 2. Least-cost Envelope.

A comparison of incremental costs can also be useful in evaluating the viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operational range of a control device.

In addition, when you evaluate the average or incremental cost effectiveness of a control alternative, you should make reasonable and supportable assumptions regarding control efficiencies. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost-effectiveness figures.

g. *What other information should I provide in the cost impacts analysis?* You should provide documentation of any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits. This is especially important in cases where recent retrofits have cost-effectiveness values that are within a reasonable range, but your analysis concludes that costs for the source being analyzed are not reasonable.

Example: In an arid region, large amounts of water are needed for a scrubbing system. Acquiring water from a distant location could greatly increase the cost effectiveness of wet scrubbing as a control option.

h. *Impact analysis part 2: How should I analyze and report energy impacts?* You should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source owner may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified and included in the cost analysis. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the cost impacts analysis. However, certain types of control technologies have inherent energy penalties associated with their use. While you should quantify these penalties, so long as they are within the normal range for the technology in question, you should not, in general, consider such penalties to be an adequate justification for eliminating that technology from consideration.

Your energy impact analysis should consider only direct energy consumption and not indirect energy impacts. For example, you could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., BTU, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. You can then convert these units into dollar costs and, where appropriate, factor these costs into the control cost analysis.

You generally do not consider indirect energy impacts (such as energy to produce raw materials for construction of control equipment). However, if you determine, either independently or based on a showing by the source owner, that the indirect energy impact is unusual or significant and that the impact can be well quantified, you may consider the indirect impact.

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region. However, in general, a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

Finally, the energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment. For example, where two options are equally cost effective and achieve equivalent or similar emissions reductions, one option may be preferred if the other alternative results in significant disruption or unemployment.

i. *Impact analysis part 3: How do I analyze "non-air quality environmental impacts?"* In the non-air quality related environmental impacts portion of the BART analysis, you address environmental impacts other than air quality due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device.

You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reductions potential of the most stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

The procedure for conducting an analysis of non-air quality environmental impacts should be made based on a consideration of site-specific circumstances. It is not necessary to perform this analysis of environmental impacts for the entire list of technologies you ranked in Step 3, if you propose to adopt the most stringent alternative. In that case, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative. Thus, any important relative environmental impacts (both positive and negative) of alternatives can be compared with each other.

In general, the analysis of impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. Initially, you should perform a qualitative or semi-quantitative screening to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, you should assess the mass and composition of any such discharges and quantify them to the extent possible, based on readily-available information. You should also assemble pertinent information about the public or environmental consequences of releasing these materials.

j. *What are examples of non-air quality environmental impacts?* The following are examples of how to conduct non-air quality environmental impacts:

- *Water Impact*

You should identify the relative quantities of water used and water pollutants produced and discharged as a result of the use of each alternative emission control system relative to the most stringent alternative. Where possible, you should assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis should consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

- *Solid Waste Disposal Impact*

You should compare the quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system with the quality and quantity of wastes created with the most stringent emission control system. You should consider the composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers.

• *Irreversible or Irretrievable Commitment of Resources*

You may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

• *Other Adverse Environmental Impacts*

You may consider significant differences in noise levels, radiant heat, or dissipated static electrical energy. Other examples of non-air quality environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when the plant is located in an area that is sensitive to environmental degradation and when the incremental emissions reductions potential of the most stringent control option is only marginally greater than the next most-effective option.

• *Benefits to the Environment*

It is important to consider relative differences between options regarding their *beneficial impacts* to non-air quality-related environmental media. For example, you may consider whether a given control option results in less deposition of pollutants to nearby sensitive water bodies.

5. Step 5: How Do I Select the ''Best'' Alternative, Using the Results of Steps 1 Through 4?

a. *Summary of the Impacts Analysis.* From the alternatives you ranked in Step 3, you should develop a chart (or charts) displaying for each of the ranked alternatives:

• Expected emission rate (tons per year, pounds per hour);

• Emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);

• Expected emissions reductions (tons per year);

• Costs of compliance—total annualized costs ($), cost effectiveness ($/ton), and incremental cost effectiveness ($/ton);

• Energy impacts (indicate any significant energy benefits or disadvantages);

• Non-air quality environmental impacts (includes any significant or unusual other media impacts, e.g., water or solid waste), both positive and negative.

b. *Selecting a ''best'' alternative.* As discussed above, we are seeking comment on two alternative approaches for evaluating control options for BART. The first involves a sequential process for conducting the impacts analysis that begins with a complete evaluation of the most stringent control option. Under this approach, you determine that the most stringent alternative in the ranking does not impose unreasonable costs of compliance, taking into account both average and incremental costs, then the analysis begins with a presumption that this level is selected. You then proceed to considering whether energy and non-air quality environmental impacts would justify selection of an alternative control option. If there are no outstanding issues regarding energy and non-air quality environmental impacts, the analysis is ended and the most stringent alternative is identified as the ''best system of continuous emission reduction.''

If you determine that the most stringent alternative is unacceptable due to such impacts, you need to document the rationale for this finding for the public record. Then, the next most-effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until you identify a technology which does not pose unacceptable costs of compliance, energy and/or non-air quality environmental impacts.

The EPA also requests comment on an alternative decision-making approach that would not begin with an evaluation of the most stringent control option. For example, you could choose to begin the BART determination process by evaluating the least stringent, technically feasible control option or by evaluating an intermediate control option drawn from the range of technically feasible control alternatives. Under this approach, you would then consider the additional emissions reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, you would still be required to (1) display and rank all of the options in order of control effectiveness and to identify the average and incremental costs of each option; (2) consider the energy and non-air quality environmental impacts of each option; and (3) provide a justification for adopting the technology that you select as the ''best'' level of control, including an explanation as to why you rejected other more stringent control technologies.

Because of EPA's experience in evaluating SO_2 control options for utility boilers, the Agency is proposing to establish a presumption regarding the level of SO_2 control that is generally achievable for such sources. Based on the cost models in the *Controlling SO_2 Emissions* report,[16] it appears that, where there is no existing control technology in place, 90–95 percent control can generally be achieved at cost-effectiveness values that are in the hundreds of dollars per ton range or less.[17] We are thus proposing a presumption that, for uncontrolled utility boilers, an SO_2-control level in the 90–95 range is generally achievable. If you wish to demonstrate a BART level of control that is less than any presumption established the final guidelines, you would need to demonstrate the source-specific circumstances with respect to costs, remaining useful life, non-air quality environmental impacts, or energy impacts that would justify less stringent controls than for a typical utility boiler. We believe that the ''consideration of cost'' factor for source-by-source BART, which is a technology-based approach, generally requires selection of control measures that are within this level of cost effectiveness. We recognize, however, that the population of utility boilers subject to BART may have case-by-case variations (for example, type of fuel used, severe space limitations, and presence of existing control equipment) that could affect the costs of applying retrofit controls. We invite comments on whether the 90–95 percent presumption is appropriate, or whether another presumption should be established instead. If commenters want to offer a different presumption they should provide documentation supporting the basis for their proposal.

For evaluating the significance of the costs of compliance, EPA requests

[16] Documentation of the presumption that 90–95 percent control is achievable is contained in a recent report entitled *Controlling SO_2 Emissions: A Review of Technologies,* EPA–600/R–00–093, available on the internet at *http://www.epa.gov/ORD/WebPubs/so2*. This report summarizes percentage controls for flue gas desulfurization (FGD) systems worldwide, provides detailed methods for evaluating costs, and explains the reasons why costs have been decreasing with time.

[17] The EPA has used the cost models in the *Controlling SO_2 Emissions* report to calculate cost-effectiveness ($/ton) estimates for FGD technologies for a number of example cases. (See note to docket A–2000–28 from Tim Smith, EPA/OAQPS, December 29, 2000).

comment on whether the final rule should contain specific criteria, and on whether such criteria would improve implementation of the BART requirement. For example, in the work of the Western Regional Air Partnership (WRAP),[18] a system is described which views as ''low cost'' those controls with an average cost effectiveness below $500/ton, as ''moderate'' those controls with an average cost effectiveness between $500 to 3000 per ton, and as ''high'' those controls with an average cost effectiveness greater than $3000 per ton.

c. *In selecting a ''best'' alternative, should I consider the affordability of controls?* Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations.

As a general matter, for plants that are essentially uncontrolled at present, and emit at much greater levels per unit of production than other plants in the category, we are unlikely to accept as BART any analysis that preserves a source's uncontrolled status. While this result may predict the shutdown of some facilities, we believe that the flexibility provided in the regional haze rule for an alternative reduction approach, such as an emissions trading program, will minimize the likelihood of shutdowns.

Nonetheless, we recognize there may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. We do not intend, for example, that the most stringent alternative must always be selected, if that level would cause a plant to shut down, while a slightly lesser degree of control would not have this effect. Where there are such unusual circumstances that are judged to have a severe effect on plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, so long as you provide an economic analysis that demonstrates, in sufficient detail for a meaningful public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis should consider whether other competing plants in the same industry may also be required to install BART controls.

V. Cumulative Air Quality Analysis

A. What Air Quality Analysis Do We Require in the Regional Haze Rule for Purposes of BART Determinations?

In the regional haze rule, we require the following in 40 CFR 51.308(e)(1)(ii)(B):

> An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the * * * [results of the engineering analysis required by 40 CFR 51.308(e)(1)(ii)(A)] * * *

This means that the regional haze rule requires you to conduct a regional modeling analysis which addresses the total cumulative regional visibility improvement if all sources subject to BART were to install the ''best'' controls selected according to the engineering analysis described above in section IV of these guidelines. We are developing guidelines for regional air quality modeling.[19]

B. How Do I Consider the Results of This Analysis in My Selection of BART for Individual Sources?

You use a regional modeling analysis to assess the *cumulative* impact on visibility of the controls selected in the engineering analysis for the time period for the first regional haze SIP, that is, the time period between the baseline period and the year 2018. You use this cumulative impact assessment to make a determination of whether the controls you identified, in their entirety, provide a sufficient visibility improvement to justify their installation. We believe that there is a sufficient basis for the controls if you can demonstrate for any Class I area that any of the following criteria are met:

(1) The cumulative visibility improvement is a substantial fraction of the achievable visibility improvement from all measures included in the SIP, or is a substantial fraction of the visibility goal selected for any Class I area (EPA believes that for such situations, the controls would be essential to ensure progress towards a long-term improvement in visibility); OR

(2) The cumulative visibility improvement is necessary to prevent any degradation from current conditions on the best visibility days.

Note that under 40 CFR 51.308(e)(1)(ii)(B), the passage cited above, the rule does not provide for modeling of subgroupings of the BART population within a region, nor for determinations that some, but not all, of the controls selected in the engineering analysis may be included in the SIP. Thus, to comply with 40 CFR 51.308(e)(1), the visibility SIP must provide for BART emission limitations for *all* sources subject to BART (or demonstrate that BART-level controls are already in place and required by the SIP), unless you provide a demonstration that *no* BART controls are justifiable based upon the cumulative visibility analysis.

VI. Enforceable Limits/Compliance Date

To complete the BART process, you must establish enforceable emission limits and require compliance within a given period of time. In particular, you must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. In addition, you must require compliance with the BART emission limitations no later than 5 years after EPA approves your SIP. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, you may prescribe a design, equipment, work practice, operation standard, or combination of these types of standards. You should ensure that any BART requirements are written in a way that clearly specifies the individual emission unit(s) subject to BART review. Because the BART requirements are ''applicable'' requirements of the CAA, they must be included as title V permit conditions according to the procedures established in 40 CFR part 70 or 40 CFR part 71.

Section 302(k) of the CAA requires emissions limits such as BART to be met on a continuous basis. Although this provision does not necessarily require the use of continuous emissions monitoring (CEMs), it is important that sources employ techniques that ensure compliance on a continuous basis. Monitoring requirements generally applicable to sources, including those that are subject to BART, are governed by other regulations. See, e.g., 40 CFR

[18] *Technical Support Documentation. Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program. An Annex to the Report of the Grand Canyon Visibility Transport Commission.* Section 6A.

[19] (The current draft of this document is entitled *Guidance for Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze.* We expect this document will be released in final form before the publication of the final rule for the BART guidelines.)

part 64 (compliance assurance monitoring); 40 CFR 70.6(a)(3) (periodic monitoring); 40 CFR 70.6(c)(1) (sufficiency monitoring). Note also that while we do not believe that CEMs would necessarily be required for all BART sources, the vast majority of electric generating units already employ CEM technology for other programs, such as the acid rain program. In addition, emissions limits must be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). In light of the above, the permit must:

- Be sufficient to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- Specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that air quality agency personnel can determine the compliance status of the source.

VII. Emission Trading Program Overview

40 CFR 51.308(e)(2) allows States the option of implementing an emissions trading program or other alternative measure instead of requiring BART. This option provides the opportunity for achieving better environmental results at a lower cost than under a source-by-source BART requirement. A trading program must include participation by BART sources, but may also include sources that are not subject to BART. The program would allow for implementation during the first implementation period of the regional haze rule (that is, by the year 2018) instead of the 5-year compliance period noted above. In this section of the guidance, we provide an overview of the steps in developing a trading program [20] consistent with 40 CFR 51.308(e)(2).

A. What Are the General Steps in Developing an Emission Trading Program?

The basic steps are to:

(1) Develop emission budgets;

(2) Allocate emission allowances to individual sources; and

(3) Develop a system for tracking individual source emissions and allowances. (For example, procedures for transactions, monitoring, compliance and other means of ensuring program accountability).

B. What Are Emission Budgets and Allowances?

An emissions budget is a limit, for a given source population, on the total emissions amount [21] that may be emitted by those sources over a State or region. An emission budget is also referred to as an ‘‘emission cap.’’

In general, the emission budget is subdivided into source-specific amounts that we refer to as ‘‘allowances.’’ Generally, each allowance equals one ton of emissions. Sources must hold allowances for all emissions of the pollutant covered by the program that they emit. Once you allocate the allowances, source owners have flexibility in determining how they will meet their emissions limit. Source owners have the options of:

—Emitting at the level of allowances they are allocated (for example, by controlling emissions or curtailing operations),
—Emitting at amounts less than the allowance level, thus freeing up allowances that may be used by other sources owned by the same owner, or sold to another source owner, or
—Emitting at amounts greater than the allowance level, and purchasing allowances from other sources or using excess allowances from another plant under the same ownership.

A good example of an emissions trading program is the acid rain program under title IV of the CAA. The acid rain program is a national program—it establishes a national emissions cap, allocates allowances to individual sources, and allows trading of allowances between all covered sources in the United States. The Ozone Transport Commission's NO_X Memorandum of Understanding, and the NO_X SIP call both provide for regional trading programs. Other trading programs generally have applied only to sources within a single State. A regional multi-State program provides greater opportunities for emission trading, and should be considered by regional planning organizations that are evaluating alternatives to source-specific BART. The WRAP has recommended a regional market trading program as a backstop to its overall emission reduction program for SO_2. Although regional trading programs require more interstate coordination, EPA has expertise that it can offer to States wishing to pursue such a program.

C. What Criteria Must Be Met in Developing an Emission Trading Program as an Alternative to BART?

Under the regional haze rule, an emission trading program must achieve ‘‘greater reasonable progress’’ (that is, greater visibility improvement) than would be achieved through the installation and operation of source-specific BART. The ‘‘greater reasonable progress’’ demonstration involves the following steps, which are discussed in more detail below:

—Identify the sources that are subject to BART,
—Calculate the emissions reductions that would be achieved if BART were installed and operated on sources subject to BART,
—Demonstrate whether your emission budget achieves emission levels that are equivalent to or less than the emissions levels that would result if BART were installed and operated,
—Analyze whether implementing a trading program in lieu of BART would likely lead to differences in the geographic distribution of emissions within a region, and
—Demonstrate that the emission levels will achieve greater progress in visibility than would be achieved if BART were installed and operated on sources subject to BART.

1. How Do I Identify Sources Subject to BART?

For a trading program, you would identify sources subject to BART in the same way as we described in sections II and III of these guidelines.

2. How Do I Calculate the Emissions Reductions That Would Be Achieved If BART Were Installed and Operated on These Sources?

For a trading program under 51.308(e)(2), you may identify these emission reductions by:

—Conducting a case-by-case analysis for each of the sources, using the procedures described above in these guidelines in sections II through V;
—Conducting an analysis for each source category that takes into account the available technologies, the costs of compliance, the energy impacts, the non-air quality environmental impacts, the pollution control equipment in use, and the remaining useful life, on a category-wide basis; or

[20] We focus in this section on emission cap and trade programs which we believe will be the most common type of economic incentive program developed as an alternative to BART.

[21] An emission budget generally represents a total emission amount for a single pollutant such as SO_2. As noted in the preamble to the regional haze rule (64 FR 35743, July 1, 1999) we believe that unresolved technical difficulties preclude inter-pollutant trading at this time.

—Conducting an analysis that combines considerations on both source-specific and category-wide information.

For a category-wide analysis of available control options, you develop cost estimates and estimates of energy and non-air quality environmental impacts that you judge representative of the sources subject to BART for a source category as a whole, rather than analyze each source that is subject to BART. The basic steps of a category-wide analysis are the same as for a source-specific analysis. You identify technically feasible control options and rank them according to control stringency. Next, you calculate the costs and cost effectiveness for each control option, beginning with the most stringent option. Likely, the category-wide estimate will represent a range of cost and cost-effectiveness values rather than a single number.[22] Next, you evaluate the expected energy and non-air quality impacts (both positive and negative impacts) to determine whether these impacts preclude selection of a given alternative.

The EPA requests comment on an approach to the category-wide analysis of BART that would allow the States to evaluate different levels of BART control options (*e.g.,* all measures less than $1000/ton vs. all measures less than $2000/ton vs. all measures less than $3000/ton) through an iterative process of assessing relative changes in cumulative visibility impairment. For example, States or regional planning organizations could use $1000 or $2000/ton as an initial cutoff for selecting reasonable control options. The States or regional planning organizations could then compare the across-the-board regional emissions and visibility changes resulting from the implementation of the initial control option and that resulting from the implementation of control options with a $3000/ton cutoff (or $1500/ton, etc). This approach would allow States and other stakeholders to understand the visibility differences among BART control options achieving less cost-effective or more cost-effective levels of overall control.

3. For a Cap and Trade Program, How Do I Demonstrate That My Emission Budget Results in Emission Levels That Are Equivalent To or Less Than the Emissions Levels That Would Result If BART Were Installed and Operated?

Emissions budgets must address two criteria. First, you must develop an emissions budget for a future year[23] which ensures reductions in actual emissions that achieve greater reasonable visibility progress than BART. This will generally necessitate development of a ''baseline forecast'' of emissions for the population of sources included within the budget. A baseline forecast is a prediction of the future emissions for that source population in absence of either BART or the alternative trading program. Second, you must take into consideration the timing of the emission budget relative to the timetable for BART. If the implementation timetable for the emission trading program is a significantly longer period than the 5-year time period for BART implementation, you should establish budgets for interim years that ensure steady and continuing progress in emissions reductions.

In evaluating whether the program milestone for the year 2018 provides for a BART-equivalent or better emission inventory total, you conduct the following steps:

—Identify the source population included within the budget, which must include all BART sources and may include other sources,
—For sources included within the budget, develop a base year[24] emissions inventory for stationary sources included within the budget, using the most current available emission inventory,
—Develop a future emissions inventory for the milestone year (in most cases, the year 2018), that is, an inventory of projected emissions for the milestone year in the absence of BART or a trading program,
—Calculate the reductions from the forecasted emissions if BART were installed on all sources subject to BART,
—Subtract this amount from the forecasted total, and
—Compare the budget you have selected and confirm that it does not exceed this level of emissions.

Example: For a given region for which a budget is being developed for SO_2, the most recent inventory is for the year 2002. The budget you propose for the trading program is 1.2 million tons. The projected emissions inventory total for the year 2018, using the year 2002 inventory and growth projections, is 4 million tons per year. Application of BART controls on the population of sources subject to BART would achieve 2.5 million tons per year of reductions. Subtracting this amount from the project inventory yields a value of 1.5 million tons. Because your selected budget of 1.2 million tons is less than this value, it achieves a better than a BART-equivalent emission total.

4. How Do I Ensure That Trading Budgets Achieve ''Greater Reasonable Progress?''

In some cases, you may be able to demonstrate that a trading program that achieves greater emissions progress may also achieve greater visibility progress without necessarily conducting a detailed dispersion modeling analysis. This could be done, for example, if you can demonstrate, using economic models, that the likely distribution of emissions when the trading program is implemented would not be significantly different than the distribution of emissions if BART was in place. If distribution of emissions is not substantially different than under BART, and greater emissions reductions are achieved, then the trading program would presumptively achieve ''greater reasonable progress.''

If the distribution of emissions is different under the two approaches, then the possibility exists that the trading program, even though it achieves greater emissions reductions, may not achieve better visibility improvement. Where this is the case, then you must conduct dispersion modeling to determine the visibility impact of the trading alternative. The dispersion modeling should determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling should identify:

—The estimated difference in visibility conditions under the two approaches for each Class I area,
—The average difference in visibility over all Class I areas impacted by the region's emissions. [For example, if six Class I areas are in the region impacted, you would take the average of the improvement in deciviews over those six areas].

[22] We request comment on whether these guidelines should recommend a weighted average of the values instead of presenting the values as a range.

[23] As required by 40 CFR 51.308(e)(2)(iii), emissions reductions must take place during the period of the first long-term strategy for regional haze. This means the reductions must take place no later than the year 2018.

[24] The base year must reflect the year of the most current available emission inventory, in many cases the year 2002, and this base year should not be later than the 2000–2004 time period used for baseline purposes under the regional haze rule.

The modeling study would demonstrate ''greater reasonable progress'' if both of the following two criteria are met:

—Visibility does not decline in any Class I area

Example: In Class I area X, BART would result in 2.5 deciviews of improvement but the trading program would achieve 1.4 deciviews. The criterion would be met because the trading program results in improvement of 1.4 deciviews, rather than a decline in visibility.

—Overall improvement in visibility, determined by comparing the average differences over all affected Class I areas

Example: For the same scenario, assume that ten Class I areas are impacted. The average deciview improvement from BART for the ten Class I areas is 3.5 deciviews (the 2.5 deciview value noted above, and values for the remaining areas of 3.9, 4.1, 1.7, 3.3, 4.5, 3.1, 3.6, 3.8 and 4.5). The average of the ten deciview values for the trading program must be 3.5 deciviews or more.

5. How Do I Allocate Emissions to Sources?

Emission allocations must be consistent with the overall budget that you provide to us. We believe it is not appropriate for EPA to require a particular process and criteria for individual source allocations, and thus we will not dictate how to allocate allowances. We will provide information on allocation processes to State and local agencies, and to regional planning organizations.

6. What Provisions Must I Include in Developing a System for Tracking Individual Source Emissions and Allowances?

The EPA requests comment generally on what the BART guidelines should require in terms of the level of detail for the administration of a trading program and for the tracking of emissions and allowances. In general, we expect regional haze trading programs to contain the same degree of rigor as trading programs for criteria pollutants. In terms of ensuring the overall integrity and enforceability of a trading program, we expect that you will generally follow the guidance already being developed for other economic incentive programs (EIPs) in establishing a trading program for regional haze. In addition, we expect that any future trading programs developed by States and/or regional planning organizations will be developed in consultation with a broad range of stakeholders.

There are two EPA-administered emission trading programs that we believe provide good examples of the features of a well-run trading program. These two programs provide considerable information that would be useful to the development of regional haze trading programs as an alternative to BART.

The first example is EPA's acid rain program under title IV of the CAA. Phase I of the acid rain reduction program began in 1995. Under phase I, reductions in the overall SO_2 emissions were required from large coal-burning boilers in 110 power plants in 21 midwest, Appalachian, southeastern and northeastern States. Phase II of the acid rain program began in 2000, and required further reductions in the SO_2 emissions from coal-burning power plants. Phase II also extended the program to cover other lesser-emitting sources. Allowance trading is the centerpiece of EPA's acid rain program for SO_2. You will find information on this program in:

—Title IV of the CAA Amendments (1990),
—40 CFR part 73 at 58 FR 3687 (January 1993),
—EPA's acid rain website, at www.epa.gov/acidrain/trading.html.

The second example is the rule for reducing regional transport of ground-level ozone (NO_X SIP call). The NO_X SIP call rule requires a number of eastern, midwestern, and southeastern States and the District of Columbia to submit SIPs that address the regional transport of ground-level ozone through reductions in NO_X. States may meet the requirements of the rule by participating in an EPA-administered trading program. To participate in the program, the States must submit rules sufficiently similar to a model trading rule promulgated by the Agency (40 CFR part 96). More information on this program is available in:

—The preamble and rule in the **Federal Register** at 63 FR 57356 (October 1998),
—The NO_X compliance guide, available at www.epa.gov/acidrain/modlrule/main.html#126,
—Fact sheets for the rule, available at www.epa.gov/ttn/rto/sip/related.html#prop,
—Additional information available on EPA's web site, at www.epa.gov/acidrain/modlrule/main.html.

A third program that provides a good example of trading programs is the the Ozone Transport Commission (OTC) NO_X budget program. The OTC NO_X budget program was created to reduce summertime NO_X emissions in the northeast United States. The program caps NO_X emissions for the affected States at less than half of the 1990 baseline emission level of 490,000 tons, and uses trading to achieve cost-effective compliance. For more information on the trading provisions of the program, see:

—Memorandum of Understanding (MOU), available at www.sso.org/otc/att2.HTM,
—Fact sheets available at www.sso.org/otc/Publications/327facts.htm,
—Additional information, available at *www.epa.gov/acidrain/otc/otcmain.html.*

The EPA is including in the docket for this rulemaking a detailed presentation that has been used by EPA's Clean Air Markets Division to explain the provisions of NO_X trading programs with State and local officials. This presentation provides considerable information on EPA's views on sound trading programs.

The EPA recognizes that it is desirable to minimize administrative burdens for sources that may be subject to the provisions of several different emission trading programs. We believe that it is desirable for any emission trading program for BART to use existing tracking systems to the extent possible. At the same time, we request comment on whether States and/or regional planning organizations should conduct additional technical analyses (and, if so, to what extent) to determine whether the time periods for tracking of allowances under existing programs (i.e., annual allowances for SO_2 for the acid rain program, and allowances for the ozone season for NO_X) are appropriate for purposes of demonstrating greater reasonable regional progress vis a vis BART. The EPA expects that if such analyses are conducted, they would be conducted in conjunction with the timelines for development of SIPs for regional haze.

7. How Would a Regional Haze Trading Program Interface With the Requirements for ''Reasonably Attributable'' BART Under 40 CFR 51.302 of the Regional Haze Rule?

If a State elects to impose case-by-case BART emission limitations according to 40 CFR 51.308(e)(1) of the regional haze rule, then there should be no difficulties arising from the implementation of requirement for ''reasonably attributable'' BART under 40 CFR 51.302. However, if a State chooses an alternative measure, such as an emissions trading program, in lieu of requiring BART emissions limitation on specific sources, then the requirement for BART is not satisfied until alternative measures reduce emissions sufficient to make ''more reasonable progress than BART.'' Thus, in that period between implementation of an emissions trading program and the satisfaction of the overall BART requirement, an individual source could be required to install BART for reasonably attributable impairment under 40 CFR 51.302. Because such an overlay of the requirements under 40 CFR 51.302 on a trading program under 40 CFR 51.308 might affect the economic and other considerations that were used in developing the emissions trading program, the regional haze rule allows for a ''geographic enhancement'' under 40 CFR 51.308. This provision addresses the interface between a regional trading program and the requirement under 40 CFR 51.302 regarding BART for reasonably attributable visibility impairment. (See 40 CFR 51.308(e)(2)(v)).

The EPA recognizes the desirability of addressing any such issues at the outset of developing an emissions trading program to address regional haze. We note that the WRAP, the planning organization for the nine western States considering a trading program under 40 CFR 51.309 (which contains a similar geographic enhancement provision), has adopted policies which target use of the 51.302 provisions by the Federal Land Managers (FLMs). In this case for the nine WRAP States, the FLMs have agreed that they will certify reasonable attributable impairment only under certain specific conditions. Under this approach, the FLMs would certify under 40 CFR 51.302 only if the regional trading program is not decreasing sulfate concentrations in a Class I area within the region. Moreover, the FLMs will certify impairment under 40 CFR 51.302 only where: (1) BART-eligible sources are located ''near'' that class I area and (2) those sources have not implemented BART controls. In addition, the WRAP is investigating other procedures for States to follow in responding to a certification of ''reasonably attributable'' impairment if an emissions trading approach is adopted to address the BART requirement based on the sources' impact on regional haze.

The specific pollutants and the magnitude of impacts under the regional haze rule and at specific Class I areas may vary in different regions of the country. We expect that each State through its associated regional planning organization will evaluate the need for geographic enhancement procedures within any adopted regional emissions trading program.

List of Subjects in 40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Carbon monoxide, Nitrogen dioxide, Particulate matter, Sulfur oxides, Volatile organic compounds.

Dated: June 22, 2001.

Christine T. Whitman,

Administrator.

In addition to the guidelines described above, part 51 of chapter I of title 40 of the Code of Federal Regulations is proposed to be amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

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

Authority: 23 U.S.C. 101; 42 U.S.C. 7410–7671q.

2. Section 51.302 is amended by revising paragraph (c)(4)(iii) to read as follows:

§ 51.302 Implementation control strategies for reasonably attributable visibility impairment.

* * * * *

(c) * * *

(4) * * *

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to ''Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities' (1980), which is incorporated by reference, exclusive of appendix E, which was published in the **Federal Register** on February 6, 1980 (45 FR 8210), except that options more stringent than NSPS must be considered. Establishing a BART emission limitation equivalent to the NSPS level of control is not a sufficient basis to avoid the detailed analysis of control options required by the guidelines. It is EPA publication No. 450/3–80–009b and is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

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3. Section 51.308 is amended by adding paragraph(e)(1)(ii)(C) as follows:

§ 51.308 Regional haze program requirements.

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(e) * * *

(1) * * *

(ii) * * *

(C) Appendix Y of this part provides guidelines for conducting the analyses under paragraphs (e)(1)(ii)(A) and (e)(1)(ii)(B) of this section. All BART determinations that are required in paragraph (e)(1) of this section must be made pursuant to the guidelines in appendix Y of this part.

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