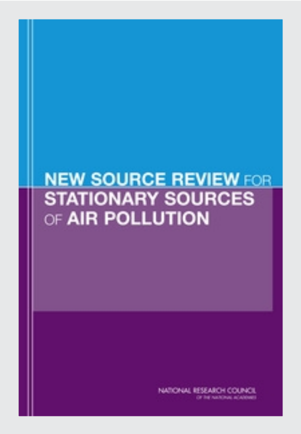

New Source Review for Stationary Sources of Air Pollution

DETAILS

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NEW SOURCE REVIEW FOR STATIONARY SOURCES OF AIR POLLUTION

Committee on Changes in New Source Review
Programs for Stationary Sources of Air Pollutants

Board on Environmental Studies and Toxicology

Division on Earth and Life Studies

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Preface

The United States Congress asked the U.S. Environmental Protection Agency (EPA) to arrange for an independent study by the National Research Council (NRC) to evaluate air quality, public health, and other impacts of EPA's final rules of December 31, 2002, and October 27, 2003, relating to the New Source Review (NSR) programs that are part of the Clean Air Act. In response, the National Research Council established the Committee on Changes in New Source Review Programs for Stationary Sources of Air Pollutants. Biographical information on the committee members is presented in Appendix A. In response to Congress, the committee produced an interim report in January 2005 and is providing its final report at this time.

In the course of preparing this report, the committee met six times. At three of the meetings, which were held in Washington, DC, officials from local, state, and federal agencies and representatives from the private sector and nongovernmental organizations, including regulated industries and advocacy groups, were invited to meet with the committee and present their views on changes to the NSR programs. Interested members of the public at large were also given an opportunity to speak on these occasions.

The committee received oral and written presentations from the following individuals: William Becker, State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO); Robert Bessette, Council of Industrial Boiler Owners; F. William Brownell, Hunton and Williams; Norbert Dee, National Petrochemical & Refiners Association; John Dege, DuPont Company; Peggy Duxbury, Calpine; Jerry Golden, while at the Tennessee Valley Authority (now a private consultant); John Bachmann, Kevin Culligan, William Harnett, Michael Ling, Philip Lorang, Margaret Victor, all of the U.S. Environmental Protection Agency; Jeffrey Holmstead, while at the U.S. Environmental Protection Agency; David McIntosh, while at the Natural Resources Defense Counsel, currently staff for Senator Joe Lieberman; Christopher Miller, while staff of the U.S. Senate Committee on Environment and Public Works, currently staff for Senator Harry Reid; William Miller, General Motors; G. William Pedersen, William F. Pedersen PLLC; Eric Schaeffer, Environmental Integrity Project; Scott H. Segal, Electric Reliability Coordinating Council; John Shanahan, staff of the U.S. Senate Committee on Environment and Public Works; Robert Slaughter, National Petrochemical and Refiners Association; Joseph Stanko, Hunton and Williams; Margaret Taylor, University of California, Berkeley; Michael Vince, Louisiana Department of Environmental Quality; Steve Wilson, Southern Company; James Witkowski, International Paper and the American Forest and Paper Association; Samuel Wolfe, New Jersey Department of Environmental Protection; and Tammy R. Wyles, Georgia-Pacific Corporation and the American Forest and Paper Association.

Mary Stewart Douglas of STAPPA/ ALAPCO provided the committee with information from the states on the status of their NSR permitting programs. Representatives of the states of Illinois, Kentucky, Michigan, New Jersey, New Hampshire, Ohio, and Washington provided additional information to a few of the committee members over the telephone.

As part of its analysis, the committee designed modeling scenarios for the Integrated Planning Model (IPM), which is owned by ICF Consulting. Arrangements for the IPM runs were funded by and coordinated through EPA because the NRC did not have a contractual relationship with ICF Consulting. The committee provided scenario input information to EPA and, in turn, EPA provided these scenarios to ICF and oversaw the implementation of the model. The IPM runs were undertaken by Boddu Venkatesh of ICF Consulting. The results of the model runs were then checked for errors by EPA employees within the Clean Air Markets Division of the Office of Air and Radiation, and then provided to the committee. The committee independently analyzed the results. Margaret Victor of EPA was instrumental in responding to requests for information from committee members. Research assistance was provided to the committee by David Evans of Resources for the Future (RFF) and Nathan Wilson, a Presidential Management Fellow who visited RFF in the summer of 2005.

We wish to thank William Happer for his valuable service as chair of the committee during the early stages of this study. He resigned appropriately from the committee to serve on the Science and Technology Advisory Committee for the U.S. Department of Homeland Security. We also would like to thank Edwin H. Clark, II, Michael Greenstone, and Brian Mannix, whose constructive service benefited the committee greatly. Dr. Clark and

Dr. Greenstone resigned from the committee for personal reasons. Mr. Mannix resigned from the committee to serve as the U.S. Environmental Protection Agency's Associate Administrator for Policy, Economics, and Innovation. The committee's work for this report was assisted by staff of the NRC's Board on Environmental Studies and Toxicology (BEST). We wish to thank Raymond Wassel, project director, and James Reisa, director of BEST. Scientific and technical information was provided by Eileen Abt, Leah Probst, Ruth Crossgrove, Mirsada Karalic-Loncarevic, Alexandra Stupple, Bryan Shipley, and Radiah Rose. Invaluable logistical support was provided by John Brown and Kemi Yai. The report was ably edited by Norman Grossblatt.

Charles Stevens, *Chair*
Committee on Changes in New Source Review
Programs for Stationary Sources of Air Pollutants

Acknowledgment of Review Participants

This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the NRC's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making its published report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their review of this report:

Andrew Bodnarik, New Hamsphire Department of Environmental Services; Linda Bui, Brandeis University; Wayne Davis, University of Tennessee, Knoxville; Daniel Farber, University of California, Berkeley; Arlene Fiore, Princeton University; Jerry Golden, private consultant; Jay Hofmann, Trinity Consultants, Inc.; Nino Kuenzli, University of Southern California; Jana Milford, Environmental Defense and University of Colorado, Boulder; Frederic Murphy, Temple University; James Schauer, University of Wisconsin, Madison; Paul Sotkiewicz, University of Florida; Sarah Wade, AJW, Inc.; Tammy Wyles, Georgia-Pacific Corporation; and Stephan Zervas, Michigan Department of Environmental Quality.

Although the reviewers listed above have provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations, nor did they see the final draft of the report before its release. The review of this report was overseen by Richard Conway, Union Carbide Corporation (retired), and Spyros Pandis, Carnegie Mellon University. Appointed by the NRC, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with the authoring committee and the institution.

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NEW SOURCE REVIEW FOR STATIONARY SOURCES OF AIR POLLUTION

Summary

The Clean Air Act (CAA) establishes a pair of programs—together known as New Source Review (NSR)—that regulate the construction and modification of large stationary sources of air pollution, such as factories and electricity-generating facilities. Under the NSR programs, a permit is required before construction may begin on a stationary source that has the potential to emit more than a specified level of emissions. A permit is also required before an existing major stationary source may be modified—that is, physically changed, or changed in operation, in a way that increases emissions.[1] The permit applicant must show that the construction or modification will include advanced emission controls. The applicant must also show that the project will not disrupt progress toward attaining the nation's ambient air quality standards nor violate limits, known as increments, that restrict growth in air pollution in clean air areas.

NSR's treatment of modifications has been particularly controversial. This is partly because of the complexities involved in determining precisely which changes qualify as modifications. In addition, the U.S. Environmental Protection Agency (EPA) in the late 1990s brought lawsuits against some electricity-generating plants based on an aggressive interpretation of its rules and a correspondingly narrow view of which projects are exempt from NSR as being "routine maintenance, repair, and replacement." A number of these suits are currently pending. In the early 2000s, EPA sought to revise its rules.

[1]EPA has long exempted routine maintenance, repair, and replacement from coverage by NSR. The scope of this exemption is in dispute, as Chapter 2 of this report discusses, as is the definition of what constitutes an emission increase.

The agency made a number of regulatory revisions to the NSR programs in December 2002 (the 2002 NSR rules). These included revisions in methods for determining what particular physical or operational changes in a facility might result in significant emission increases and thus invoke NSR requirements. In support of these revisions, EPA concluded that the 2002 changes would be likely to result either in some degree of emission reduction or in no significant changes in emissions. However, EPA indicated that it did not have sufficient data to quantify the emission changes that might result and also said it could not reliably determine the locations of any potential emission changes. Thus the agency could not estimate the rule's impacts on public health.

In October 2003, EPA made additional NSR revisions, referred to as the equipment replacement provision, that allow facilities to make certain equipment replacements without an NSR permit even if pollutant emissions increase significantly, as long as the facility does not exceed its maximum level of allowable emissions.[2] This expanded the scope of the exemption from NSR for "routine" maintenance. After conducting a computer model analysis of the electric power industry and six case studies of other industrial sectors, EPA concluded that the equipment replacement provision would have little impact on future emissions.

The rule changes have provoked much dispute. EPA and other supporters of the revisions say the NSR changes will provide industry with greater flexibility in operating its facilities, increase energy efficiency, and help to modernize plants—all without causing substantial emission increases. Opponents say that the NSR revisions will slow progress in cleaning the nation's air, and thus damage human health, and that the changes are not necessary to provide operating flexibility in industry.

Congress directed EPA to arrange for an independent study by the National Research Council (NRC) to estimate the effects of the 2002 NSR rule changes and the 2003 equipment replacement provision. Congress called for an assessment of changes in emissions of pollutants regulated under the NSR programs, the effects on human health, and changes in operating efficiency (including energy efficiency), pollution prevention, and pollution-control activities at facilities subject to the revised NSR programs. The study task statement specified that the study should consider the data and methods necessary to assess specific effects of the NSR rules expected to occur in the coming years.

Several factors made it difficult to assess the effects of the NSR rule changes. As of mid-2006, the 2002 NSR rules have gone into effect in only a few states, and few permits have been issued under the 2002 rules. In ad-

[2]Sources often emit less than their allowable maximum. Therefore, it is often possible for a source to increase emissions without exceeding its allowable maximum.

dition, portions of the 2002 rules have been struck down by the D.C. Circuit Court of Appeals as beyond EPA's authority under the Clean Air Act. The equipment replacement provision has not gone into effect in any state. A panel of the D.C. Circuit Court of Appeals stayed the rule change before its effective date and concluded in March 2006 that the rule was beyond EPA's authority under the Clean Air Act. In addition, in March 2005, while this report was being prepared, EPA promulgated another rule, the Clean Air Interstate Rule (CAIR)—a "cap-and-trade" program aimed at lowering emissions from electric power plants in eastern and midwestern states. In those states, CAIR may have a substantial effect on the consequences of the NSR reforms. However, CAIR is subject to judicial review.

The shifts in the regulatory and legal landscape since the committee began its evaluations do not negate the core value of this report. The fundamental issue raised by the 2002 and 2003 rules—the question of which alterations at existing major sources ought to be subject to NSR—remains important because those sources emit a large portion of the total air-pollution burden in some areas. In addition, EPA is considering a number of other rule changes, described in Chapter 2, that would narrow the possible applicability of NSR in various ways.

Any significant change in NSR should be accompanied by careful prospective and retrospective analyses. This report can serve as a case study on how such analyses should be conducted. Although the report focuses on the 2002 and 2003 rules, its analytic framework applies as well to other possible changes in NSR and to other regulatory contexts. Our methodology and recommendations about necessary data and information, and the need for development of better research methods, are as important as the evaluations in this report regarding the 2002 and 2003 rules.

The committee's analyses of existing data and computer simulations provided several insights into the potential effects of the NSR changes, as indicated in this report. However, the committee concluded overall that, because of a lack of data and the limitations of current models, it is not possible at this time to quantify with a reasonable degree of certainty the potential effects of the NSR rule changes on emissions, human health, energy efficiency, or on other relevant activities at facilities subject to the revised NSR program. Use of anecdotal information, by itself, is insufficient to evaluate changes in performance expected from the broad range of facilities affected by the NSR rule changes and to evaluate what effects might occur as a result of those changes. Additional data and a combination of empirical analysis and modeling will be necessary to quantify the effects of the NSR rule changes and associated uncertainties. In the interest of demonstrating how such an analysis might be undertaken in the future, the committee provides the following in this report:

- Several model scenarios of how NSR changes might affect national emissions in the electricity-generating sector based on different assumptions about future regulations and decision making in the industry.
- A limited analysis of permit activity and emission records for a variety of industries.
- Recommendations for specific analytical approaches that will improve the likelihood of finding quantitative answers to the study questions, and for data collection and modeling improvements that could be used to carry out these approaches.

THE COMMITTEE'S ANALYSIS OF POTENTIAL EFFECTS OF RULE CHANGES ON EMISSIONS FROM ELECTRICITY-GENERATING FACILITIES

The committee focused primarily on the electricity-generating sector, especially coal-fired power plants, because that sector dominates national emissions of sulfur dioxide (SO_2) and is the major stationary source contributor of nitrogen oxides (NO_x). Those two pollutants are important contributors to concentrations of airborne particulate matter, and NO_x is an important precursor to ozone. Particulate matter and ozone are of considerable concern because of the risk they pose to public health.

Older power plants have higher emission rates than newer facilities and contribute proportionately more to total emissions than to electricity generation. More than 60% of all coal-fired electricity-generation capacity in the United States currently lacks the kinds of controls for SO_2 and NO_x emissions that have been required under NSR. Also, the older facilities are more likely than newer facilities to undergo maintenance, repair, and replacement of key components, so a substantial portion of emissions from the electricity-generating sector is potentially affected by the NSR rule changes. The committee focused on the impact of the 2003 equipment replacement provision because that rule was expected to influence the electricity-generating sector more than the 2002 NSR rules. Because the equipment replacement provision has not been implemented and there are no actual data, modeling was necessary to estimate its potential effects on emissions of SO_2 and NO_x. The committee used an expanded version of the approach used by EPA in its prospective regulatory impact analysis of the 2003 equipment replacement provision.

In assessing the potential effects of the equipment replacement provision compared to the prerevision NSR rules,[3] EPA assumed that, under

[3]In this report, the term *prerevision NSR rules* refers to the NSR rules prior to the 2002 and 2003 changes.

the prerevision rules, owners of electricity-generating facilities would have chosen to avoid NSR requirements by deferring maintenance, thus resulting in deterioration of facility performance. The committee asked EPA to run the model using different assumptions about decisions by owners of electricity-generating facilities under the prerevision NSR rules that, for various percentages of electricity-generating facilities, owners would add emission controls, upgrade their electricity-generating processes so as to create less pollution, or retire their facilities. Three sets of model scenarios were run assuming that those choices would be made for a minimum of 2%, 5%, and 7.5% of facilities each year, respectively. Those scenarios allowed the committee to consider the possibility that aggressive implementation of the prerevision NSR rules would have compelled changes to be made at coal-fired facilities to a much greater extent than would the equipment replacement provision. That possibility could occur if aggressive NSR enforcement of the prerevision rules would have resulted in substantial replacement of old equipment. In examining this range of assumptions for a bounding analysis, the committee is not judging that these scenarios are more likely than the NSR-avoidance assumptions of the EPA analysis.

Like the EPA analysis, the committee considered the impacts of the equipment replacement provision under the regulations for SO_2 and NO_x that existed when the rule was promulgated.[4] In addition, the committee's analyses went beyond EPA's regulatory impact analysis by considering applicable regulations that have not yet been implemented, such as CAIR. The committee also considered alternative scenarios about economic and technological conditions.

The Model

In EPA's analysis, an industry-sector model called the Integrated Planning Model (IPM)[5] was used. IPM estimates future emissions based on different assumptions regarding (1) decision making in the industry, (2) values of important parameters such as the percentage of plants that might have complied with the prerevision rules or retired, and (3) other relevant environmental policies and enforcement actions. IPM does not explicitly model NSR-relevant decisions about equipment repair and replacement, so

[4]Model scenarios included emission limits of the acid-rain program enacted under Title IV of the 1990 Clean Air Act amendments. They also included emission limits of a program (commonly referred to as the "NO_x SIP Call") to mitigate NO_x emissions that contribute to ozone formation.

[5]IPM is a deterministic model of the electricity sector that uses linear programming techniques to find a lowest-cost approach to determine how electricity generators might meet projected demand and the amounts and types of generating-capacity investment and retirement sufficient to meet peak demand and regional reserve requirements.

incorporating the NSR rule changes in IPM requires subjective judgments by those running the model.

The committee concludes that current versions of IPM, or similar industry-sector models, cannot be used as the sole basis for estimating the effects of the NSR rule changes on electricity-generating-facility emissions. Like all current power-sector models, there is substantial uncertainty in the estimates from IPM even for assessing broad patterns. For example, the model assumes essentially perfect foresight on the part of facility decision makers, an unrealistic premise. At best, IPM is a tool for estimating national, or perhaps regional, patterns of emissions, which are important to public health but can overlook significant local variations in effects on a smaller geographic scale. Because uncertainties are greater at smaller scales than on the national level, conclusions that can be drawn from current modeling are limited.

Results

The committee considered both an NSR-avoidance assumption regarding prerevision NSR compliance (the basis of the previous EPA analysis), as well as assumptions that the prerevision NSR rules would lead to retrofits of pollution-control equipment that would have otherwise not taken place. Based on the committee's IPM analysis, the potential effects of the equipment replacement provision on national emissions from electricity-generating facilities depend on whether CAIR is assumed to be in place or not. The IPM results suggest the following conclusions if indeed the prerevision NSR rules would have compelled significantly more retrofits:

- For SO_2, without implementation of CAIR, the equipment replacement provision would be expected to result in a moderate decrease in emissions in the first 6 years or so (compared with prerevision NSR), followed by a period of relatively little change in the next 6 years or so.[6] However, after the first 12 years, if it is assumed that prerevision NSR rules would have caused all coal-fired electricity-generating facilities to add emission controls, the equipment replacement provision would be expected to cause a relative increase in emissions, perhaps substantial, from the electricity-generating sector compared with the prerevision NSR case (see Chapter 6).
- If CAIR is assumed to be implemented, the model estimates minimal differences in total SO_2 emissions between the prerevision rules and the

[6]The decrease is expected, under these assumptions, because the equipment replacement provision would significantly increase the value of Title IV SO_2 emission allowances to facilities, making overcompliance and banking of allowances in early years more attractive (see Chapter 6).

equipment replacement provision, even if all electricity-generating facilities would have added emission controls under the prerevision rules.

- For NO_x, without implementation of CAIR, the equipment replacement provision rule changes would be expected to cause an increase in emissions after the first few years; this increase is larger when the prerevision NSR is assumed to compel greater amounts of emission controls.
- If CAIR is implemented, the model estimates a minimal change in NO_x emissions; although, after the first 12 years or so, the equipment replacement provision would be expected to cause a moderate increase in emissions if all facilities would otherwise have added emission controls under prerevision NSR rules.

The model estimates have substantial uncertainty, because facility-level decision making in response to NSR rule changes is difficult to predict, and many assumptions about such decisions that are embedded in the model may not be realistic depictions. Also, the net effects of the equipment replacement provision would depend heavily on how electricity producers respond to the rule changes. Under the revised NSR rules, fewer investment projects would require NSR permits, thus reducing the costs of such projects, both in terms of avoiding NSR-permit-related emission controls and potential delays and uncertainties caused by the NSR permitting process. The newer production equipment might be cleaner than the older equipment it replaces—even if not as clean as the equipment that NSR might require—and might result in some reduction in emissions. Therefore, if the revised NSR rules encouraged additional investment in new equipment, the result could be a reduction in emissions at some facilities, if those facilities would have avoided triggering prerevision NSR by delaying investment in process upgrades. Key questions are whether many investment projects that were discouraged by the prerevision rules would proceed under the revised rules, and how much those projects would reduce emissions. Available empirical data are not sufficient to formally evaluate this effect.

It is reasonable to conclude that the implementation of the ERP could lead to SO_2 and NO_x emission increases in some locations and decreases in others. However, the magnitude of the changes and the number of geographic areas affected could not be assessed. Although IPM can provide some reasonable insights about national emission patterns under different scenarios, such insights are on a scale too large for assessment of health effects and should not be used for such purposes.

COMPARISON OF EMISSION CONTROL COSTS FOR ELECTRICITY-GENERATING FACILITIES

The committee's analyses allowed for a comparison of the cost of achieving SO_2 and NO_x emissions reductions through aggressive implementation of the prerevision NSR rules versus lowering the caps on allowable national emissions with a market-based trading program. (NSR has local objectives as well, as mentioned in Chapter 2, so this comparison, which is limited to national emission reduction, should not be taken as attempting an overall assessment of NSR.) The IPM analysis suggests that a national market-based trading program with emission caps below those specified by CAIR could produce emission reductions at approximately one third or less of the cost of aggressive implementation of the prerevision NSR rules. This is primarily because a more-traditional regulatory approach, such as the NSR rules, tends to be less cost efficient at achieving emission reductions across multiple facilities than market-based approaches. When the IPM simulation allowed facilities to trade emissions in the lower-emission-cap scenario, the model predicted greater use of low-sulfur coal and natural gas and fewer retrofits of emission controls by the affected facilities. IPM results suggest that if lower national emissions of pollutants are desired, setting emissions caps below those set for CAIR would be a more cost-effective means of attaining national emission goals than the type of regulatory approach used for the NSR rules. However, because of the limitations in IPM, emissions could not be assessed at the facility level, and any effective strategy must be designed and implemented to guard against potential pitfalls, such as worsening air quality in a particular local area. Whether such a strategy should be undertaken is a matter of policy and outside of this committee's scope of work.

THE COMMITTEE'S ANALYSIS OF POTENTIAL EFFECTS OF RULE CHANGES ON EMISSIONS FROM SECTORS OTHER THAN ELECTRICITY GENERATION

Other industry sectors besides the electricity-generating sector would have been affected by the equipment replacement provision. In addition, the other sectors are affected by the 2002 NSR rule changes, which have gone into effect in some locations. To gain some insight about the industry sectors other than the electricity-generating sector that are expected to contribute most to emission and air-quality changes as a result of the NSR rule changes, the committee evaluated some permit data and emissions inventories from the recent past. A substantial number of NSR permits have been issued for facility modifications within industry sectors, such as stone, clay, and glass products; paper and allied products; chemicals and allied products; and food and kindred products. Those modifications have led to increased emissions clustered within certain locations. For example, permits for facilities within the cement industry and pulp and paper industry have resulted in a substantial contribution to permitted NO_x emissions for facility modifications. The geographic clustering of NO_x emissions from those industry sectors in Texas, Pennsylvania, Georgia, and Michigan, near areas that are in nonattainment of ambient air quality standards for particulate matter and ozone, indicates that further research into the influence of the NSR rule changes on the sectors would be warranted. Similar conclusions can be reached for other pollutants, on the basis of information on permits issued for modifications in the chemical, cement, and pulp and paper industries for SO_2; chemical and allied products, metal industries, and pulp and paper for particulate matter; and pulp and paper, soybean oil mills, and lumber and wood products for volatile organic compounds. Although the 2002 rules have been implemented in few states, and available data are not sufficient to quantify the effects of the NSR rule changes, the existing data provide some insight about areas on which to focus for future analyses.

In addition to permit data, more information is needed on facilities that make changes not requiring an NSR permit, so as to assess the extent to which projects that lower emissions or improve efficiency are undertaken in response to the revised rules. Also, suitable industry simulation models are not available for industrial sectors other than the electricity-generating sector. The only basis at this time for determining the effects of the NSR rule changes on those other sectors are anecdotal evidence and a few case studies, which in the committee's judgment, do not provide an adequate basis for the evaluations needed.

FUTURE ANALYTICAL APPROACHES FOR DETERMINING EFFECTS OF RULE CHANGES

Modeling efforts to date have provided some insights into the potential effects of the NSR rule changes on national emissions from the electric power industry. However, such models cannot be used to quantify how much emissions may change at individual facilities and thus cannot be used to assess potential health effects as is usually done for other air regulations. In order to further evaluate the effects that the committee was asked to consider, an investigator would need to analyze a set of actual data on what individual facilities are doing or have done in response to the NSR rule changes.

The committee considered a number of potential analytic approaches that could be used to evaluate the effects of the NSR rule changes, including econometric and statistical models, process engineering models for particular facilities, and simulation models for the electric power sector. Each of the approaches has its strengths and weaknesses. Rigorous assessments of the impacts of the NSR rule changes should include both empirical analysis of information such as permit data or investment activities, and modeling approaches for industry-sector responses to regulatory changes or air-quality effects of emission changes.

Future Analysis of Permit Data

Analysis of NSR permit data could be used to determine how NSR permitting activity has changed as a result of the rule changes. However, current databases are inadequate for such an analysis. In addition, permit data would capture only projects that are actually implemented, omitting investments that may have been forgone to avoid NSR requirements. If the databases included minor-construction-permit information at the state level for investment projects that no longer needed NSR permits, such analyses might plausibly capture the major effects of the rule changes on the overall level of investment activity.

Future Analysis of Investment Activities

The NSR rule changes have been implemented in some states and not in others, which provides an opportunity in the future to observe differences in outcomes that may be attributable to implementation of the rule changes. Data on investment activity, such as those collected by the U.S. Census Bureau, could be used to evaluate the rule changes (see Chapters 4 and 5). The evaluation depends on comparing investment activity at facilities in states where the revised NSR rules have been implemented with investment activity at facilities in states that have not implemented the changes. Facility-level data on emissions could also be analyzed to see how NSR rule changes affected emissions. Analysis of investment activities would also disclose improvements to facilities that do not involve NSR permits. However, such analyses will not be possible for several years for a variety of reasons—the data become available only after a 3-year lag, many states have not yet implemented the rule changes, and investment decisions can take years to be carried out. A complete econometric analysis may therefore not be feasible until 2009 or 2010. Even at that point, the impact of the NSR rule changes on investment activity will not be very precisely estimated; if the NSR rule changes cause less than approximately an 11% change in investment, the analysis may not show a statistically significant result (see Chapter 5).

Future Assessment of Human Health Effects

After assessing the effects of NSR rule changes on facility investment behavior and related emissions, atmospheric transport and fate models will need to link emissions changes with incremental changes in ambient concentrations of pollutants of interest. In order to make health-effects assessments, modeling will also be needed to capture detailed meteorologic factors with appropriate geographic specificity (for example, on a local scale) and on a relevant time scale to assess the influence of population exposures to changes in ambient pollutant concentrations. Given the variability in meteorologic factors, stack characteristics, and downwind population density, the population health benefits per unit emissions can vary by more than a factor of 10 across sites even if relationships between air-pollution concentrations and health responses are assumed to be linear. The variability could be even greater if the relationships are not linear. This reinforces the importance of understanding detailed geographic patterns of emission increases and decreases as a result of NSR rule changes.

CARRYING OUT THE APPROACHES: MODELING NEEDS AND DATA COLLECTION

To improve the likelihood that the effects of the NSR rule changes can be better estimated, additional data collection and improved modeling methods are needed for each of the recommended approaches. These improvements might also be valuable for measuring the effects of other regulatory changes regarding air-pollutant emissions. Prospective data collection in key areas could lead to more informed policy decisions in the future.

Modeling Improvements

Industry-Sector Models

Industry-sector models represent the primary analytical approach now available. In principle, those models are most relevant to the committee's task because they can theoretically capture the geographic location of emission changes necessary for air-quality and human-health impact assessment. The committee recommends several steps that could potentially improve the reliability of regional (if not local) emission estimates and could allow for quantification of effects on air quality and health.

Recommendation: Electricity-sector models, such as IPM, should be refined to account better for the influence of NSR and related regulations on plant-level decision making. Although this is clearly a daunting task, sequential refinements could capture the factors that influence decisions to retrofit a facility or perform maintenance activities.

Recommendation: Electricity-sector models should be refined to facilitate analyses of the sensitivity of model results to changes of input parameters and to conduct more formal uncertainty analysis. In particular, periodic expert review of key inputs and components

of a model are important for a more-informed updating of the model.

Recommendation: Steps should be taken to compile the necessary input data to support development of industry-sector models of industries other than electricity generation to allow for more-informed future analyses. Development of those models should strive to achieve qualities recommended for electricity-sector models.

Econometric Models

Reduced-form econometric analyses of investment and emission data from sets of facilities in various states that differ in the effective date of the NSR rule changes could be a useful complement to industry-sector simulation models. Such analysis could be accomplished through the use of an econometric analysis model that focuses on total investment spending or emissions from an entire facility (see Chapter 5).

Recommendation: Econometric analysis of facility-level investment and emission data should be carried out when the necessary data become available, recognizing that substantial research time and resources will be needed to carry out the analysis.

Data Collection Improvements

There is no central database on issued NSR permits. This constitutes an important data gap. State data on NSR permits and minor-construction permits are generally limited and are often kept in paper form. There appears to be no attempt by states to develop permit databases that are compatible with each other. Development of a standardized database program adopted by all states could make analyses of these permit data more plausible.

Recommendation: Information on issued permits should be collected in a systematic format (same data fields, field layouts, variable definitions, and so on) in a database maintained by EPA. This database should include the full range of state and federal permits, including both NSR and minor permits. Resources should be made available so that EPA and other agencies can collect the information consistently in the future. The information could inform future assessments of NSR rule changes and, perhaps more important, could provide the foundation for prospective assessments of other future regulatory actions.

Recommendation: Data should be compiled when the NSR rule changes became applicable for facilities in different states as well as on perceptions at regulated firms and among regulators regarding the timing of the rule changes. Such information will help to identify when investment decisions are likely to be affected by the NSR rule changes. The data should be collected both in areas that have attained air-quality standards as well as in those that have not. The information can be gathered at the state level in a systematic format and compiled by EPA. Because the number and types of facilities that may be subject to NSR varies across states, existing data can be used to target data-collection efforts (see Chapter 7).

CONCLUSION

This report serves as a case study on the types of information and methods needed to analyze the effects of significant changes to the NSR programs. Overall, because of a lack of data and the limitations of current models, available information is insufficient to quantify the effects of the NSR rule changes with reasonable certainty. A combination of empirical analysis and modeling will be necessary to determine the effects of the implemented NSR rule changes and associated uncertainties for affected industry sectors. Although current modeling approaches can provide some reasonable insight about national emission patterns under different scenarios, such insights are on too large a scale for assessment of health effects and should not be used for such purposes. If industry-sector modeling were improved, it could in principle capture the geographic location of emission changes necessary for air-quality and human-health assessment. The committee recommends that EPA and other government agencies undertake and sustain the data-collection efforts outlined in this report and that future efforts to assess NSR effects take account of the methods presented here. Our methodology and recommendations about necessary data and information and the development of better research methods are as important as the evaluations of this report regarding the 2002 and 2003 rules.

1

Introduction

The Clean Air Act (CAA) includes New Source Review (NSR) permit programs that apply to major stationary sources of air pollution, such as factories and electric generating facilities. Under NSR, each new major stationary source must have a permit before construction begins, and an existing major stationary source must have a permit before a physical or operational change is made that would result in a significant increase in pollutant emissions. NSR programs allow construction or modification of an emission source only if the operator first shows that emissions will be reduced as much as practicable.[1] In addition, construction or modification cannot result in significant deterioration of air quality in areas that meet the National Ambient Air Quality Standards (NAAQS)[2] or interfere with progress toward attainment in areas where air quality violates NAAQS.

On December 31, 2002 (67 Fed. Reg. 80186 [2002]), and October 27, 2003 (68 Fed. Reg. 61248 [2003]), the U.S. Environmental Protection Agency (EPA) promulgated changes in the NSR programs were published. The changes have resulted in controversy. EPA and other supporters of the changes say that they will provide greater flexibility for industry, increase the energy efficiency of industrial facilities, and contribute to the modernization

[1]The extent of emission reductions that can be accomplished for a proposed new or modified source is based on a case-by-case evaluation.

[2]The NAAQS specify the maximal allowable concentrations of six pollutants in ambient air that are protective of public health and welfare: carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide. These pollutants are known as criteria pollutants because the Environmental Protection Agency prepares "criteria documents" for them that describe their sources and effects.

of American industry—all without damaging the environment. Opponents say that the changes will slow progress in cleaning the nation's air and thus damage human health and that they are not necessary to provide flexibility (GAO 2004). (Chapter 2 describes the NSR changes in the context of the CAA.)

As detailed below, Congress asked the National Research Council (NRC) to study the 2002 and 2003 regulations. There have been extensive developments during the course of this examination—for instance, EPA's promulgation in 2005 of the Clean Air Interstate Rule (CAIR). The most important changes have come from decisions of the D.C. Circuit Court of Appeals, the court that has jurisdiction over challenges to EPA regulations. (These decisions are described in Chapter 2.) In July 2005, the D.C. Circuit invalidated portions of the 2002 rule as contrary to the CAA or as insufficiently explained (New York v. EPA, 413 F.3d 3 [D.C. Cir. 2005]). Then, in March 2006—while this report was in the final stages of preparation—the D.C. Circuit vacated the 2003 rule, finding that it conflicts with the Act's language (New York v. EPA, 443 F.3d 880 [D.C. Cir. 2006]).

The shifts in the regulatory landscape since the committee began its evaluations do not negate the core value of this report. The fundamental issue raised by the 2002 and 2003 rules—the question of which alterations at existing major sources ought to be subject to NSR—remains important. As is detailed in Chapter 7, existing major sources emit a large portion of the total air-pollution burden in some areas. In addition, the topic continues to be one of current concern. EPA is considering a number of rule changes, described in Chapter 2, that would narrow the possible applicability of NSR in various ways. The most important example is EPA's proposal that a physical or operational change at an electric generating facility be subject to NSR only if the maximum hourly emissions from the unit would increase (70 Fed. Reg. 70565 [2005]).

Any significant change in NSR should be accompanied by careful prospective and retrospective analyses. This report serves as a case study on how such analyses could be conducted. Although the report focuses on the 2002 and 2003 rules, its analytic framework applies as well to other possible changes in NSR and to other regulatory contexts. Our methodology and recommendations about necessary data and information, and development of better research methods are as important, as are the evaluations of this report regarding the 2002 and 2003 rules.

CHARGE TO THE COMMITTEE

Because of the controversy over the NSR changes, Congress mandated that EPA arrange for the NRC to assess potential effects of EPA's final rules of December 2002 and October 2003. The NRC was asked to assess changes in emissions of pollutants regulated under the NSR programs, effects on human health, and changes in operating efficiency, pollution prevention, and pollution control at facilities subject to NSR. (The congressional mandate for the study is in Appendix B.)

In response to the request, the NRC established the Committee on Changes in New Source Review Programs for Stationary Sources of Air Pollutants (see Appendix A). The committee was also asked to estimate and evaluate the amount of uncertainty associated with the effects being considered. In addition, the committee was asked to consider the data and methods necessary to assess specific effects of the NSR rules expected to occur in the coming years, taking into account the relatively short time that will have elapsed since the promulgation of the NSR rules and the economic conditions that have prevailed in the interim. (The committee's full statement of task is in Appendix C.)

Congress asked that an interim report of the committee's study be provided and that it include all conclusions and recommendations the committee determined to be feasible and appropriate at that stage in its study. In January 2005, the committee provided an interim report (NRC 2005) that synthesized relevant background information to serve as a basis of the final report. It also described the committee's general approach for assessing the effects it was asked to address. Because information gathering and analysis had not been completed when the interim report was written, the committee had not reached its final conclusions or recommendations in response to its charge. Much of the committee's discussion presented in the interim report has been carried forward in this final report. However, the reader is referred to the interim report itself in some cases.

Effective decisions to manage air quality are made by elected and appointed leaders in the context of diverse social, economic, and political considerations. This report is intended to provide input to those leaders that is focused only on scientific and technical aspects. Congress did not ask the NRC to determine the desirability of the new NSR rules or to decide whether they should be revised or repealed. Such conclusions involve considerations that go beyond science and involve value judgments, such as how to weigh environmental protection against other societal goals. Congress also did not ask for an appraisal of whether EPA acted within the scope of its authority and, if it did, whether its decisions were reasonable. Finally, Congress did not ask the NRC to investigate any effects of the NSR changes other than effects on emissions, human health, and industry actions concerning efficiency, pollution control, and pollution prevention. The committee was directed to focus on those specific effects, so it did not consider other possible effects of the NSR changes, such as effects on nonhuman biota (for example, agricultural crops and forests), atmospheric visibility, and materials (for example, monuments and buildings). The committee was not asked to and did not include emissions of greenhouse gases, such as carbon dioxide and methane, in its assessment; EPA does not consider these gases to be regulated under the CAA. Emissions of hazardous air pollutants (HAPs) may be affected by NSR because many HAPs are subsets of volatile organic compounds or particulate matter, both of which are regulated by NSR. However, since 1990, a separate program has regulated the construction and modification of sources that emit HAPs (CAA § 112(d)(3), 42 USC § 7412(d)(3)),[3] and Congress did not ask the committee to analyze the effects of any changes in emissions of HAPs.

In carrying out its charge, the committee considered relevant scientific and technical documents prepared by EPA, other federal agencies, states, industry, and environmental and other nongovernment organizations. The committee sought to gather information on how the revised NSR rules may affect emissions, air quality, public health, and industry actions concerning pollution control, pollution prevention, and operating efficiency. It also gathered background information on the types of facilities that may be subject to NSR rules, including numbers and ages of facilities, emission trends, locations relative to NAAQS nonattainment areas, and population sizes downwind of facilities. The committee sought information from states on the status of their NSR permitting programs and efforts to collect and maintain relevant databases. Because of the various types of industries potentially affected by NSR, the committee could not consider the effects of the rule changes for each type in detail; instead, it focused on a few representative industries. Of the various types of pollutants affected by NSR programs, much of the committee's assessment focused on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), not because of their own health effects, but because of their contribution to the formation of airborne particulate matter, and NO_x is an important precursor to ozone in the lower atmosphere. The electric-power sector was a primary focus of many of the committee's assessments. The sector, especially coal-fired power plants, dominates national emissions of SO_2 and NO_x, compared with other large stationary sources that may be affected by NSR.

Because many of the outcomes that the committee has been asked to consider can be affected by factors outside the realm of NSR, the committee considered other factors, such as economic conditions and government investment in research and development. Those factors can play an important role in the decisions firms make on whether to proceed with a given investment project that may be subject to NSR requirements. For example, in the case of the electric power industry, conditions such as growth in the demand for electricity, fuel prices, and investment costs for different electricity-

[3]In the CAA amendments of 1990, Congress provided a list of 189 compounds, such as benzene, formaldehyde, and mercury compounds, to be controlled by EPA as HAPs.

production and pollution-control technologies are important considerations. The committee also recognizes that future developments in other pollution laws and regulations could have a substantial influence on the effects of NSR changes. Thus, the committee strove to consider the plausibility, significance, and interactions of those other relevant requirements.

To establish a background and context for the committee's technical and scientific analysis, Chapter 2 provides a regulatory overview of the NSR programs in the context of the CAA. It also describes and discusses the NSR changes that are the subject of the committee's evaluation. Chapter 3 considers emission sources subject to NSR and technology options available for their control. Chapter 4 continues discussions begun in the committee's interim report on an analytic framework for assessing effects of NSR changes. Chapter 5 discusses econometrics as a way to measure effects of the NSR changes. Chapter 6 assesses the potential efficiency, technology, and emission implications of the NSR changes on electricity-generating facilities. Chapter 7 examines contributions that emission sources subject to NSR may make to ambient air quality and relationships between specific air pollutants and health effects. Chapter 8 presents the committee's overall conclusions and suggests the kinds of analyses that are needed to address the information needs identified in this report. Terms and abbreviations used in this report are defined in a section after the references.

2

Regulatory Overview

INTRODUCTION

The Clean Air Act (CAA) requires the U.S. Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) at levels that protect public health and welfare (see Table 2-1). These pollutants are known as criteria air pollutants because the NAAQS are based on "criteria documents" that describe the sources and effects of each pollutant.

The CAA seeks to control emissions of air pollutants to ensure that the NAAQS are attained and maintained and that air quality that is better than the NAAQS is protected. The statute's mechanisms include a pair of programs that together are known as New Source Review (NSR). These programs establish requirements that must be met before a large stationary source of pollution (a source with a fixed location, such as a factory or an electricity-generating facility) may be constructed or modified. NSR thus covers modifications of existing large sources as well as construction of new ones.

One NSR program, Prevention of Significant Deterioration (PSD), applies to the construction or modification of any "major emitting facility" locating in an "attainment area"—an area whose air quality meets the NAAQS or is unclassifiable (CAA § 165(a), 42 USC § 7465(a)). The other, commonly called Part D NSR, applies to the construction or modification of "major stationary sources" (slightly different from "major emitting facilities") in "nonattainment areas"—those classified as not meeting the NAAQS (CAA § 172(b)(5), 42 USC § 7502 (b)(5)). We provide an overview of both NSR programs later in this chapter.

TABLE 2-1 National Ambient Air Quality Standards

Pollutant or Indicator	Averaging Times	Primary Standard	Secondary Standard
Carbon monoxide (CO)	8 hr[a] 1 hr[a]	9 ppm (10 mg/m^3) 35 ppm (40 mg/m^3)	None None
Lead (Pb)	Quarter (average)	1.5 µg/m^3	Same as primary
Nitrogen dioxide (NO_2)	Year (average)	0.053 ppm (100 µg/m^3)	Same as primary
Particulate matter < 10 µm in aerodynamic diameter (PM_{10})[f]	Year (average)[b] 24 hr[a]	50 µg/m^3 150 µg/m^3	Same as primary Same as primary
Particulate matter < 2.5 µm in aerodynamic diameter ($PM_{2.5}$)[f]	Year (average)[c] 24 hr[d]	15 µg/m^3 65 µg/m^3	Same as primary Same as primary
Ozone (O_3)	8 hr[e]	0.08 ppm	Same as primary
Sulfur oxides (SO_x)	Year (average) 24 hr[a] 3 hr[a]	0.03 ppm 0.14 ppm —	— — 0.5 ppm (1,300 µg/m^3)

[a]Not to be exceeded more than once per calendar year.
[b]To attain this standard, the expected annual average PM_{10} concentration at each monitor in an area must not exceed 50 µg/m^3.
[c]To attain this standard, the 3-year average of the annual average $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed 15 µg/m^3.
[d]To attain this standard, the 3-year average of the 98th percentile of 24-hr concentrations at each population-oriented monitor in an area must not exceed 65 µg/m^3.
[e]To attain this standard, the 3-year average of the fourth-highest daily maximal 8-hr average O_3 concentrations measured at each monitor in an area over each year must not exceed 0.08 ppm.
[f]EPA has recently proposed to revise these standards (see 71 Fed. Reg. 2620 [2006]).

SOURCE: EPA 2004a.

The CAA defines a modification as "any physical change, or change in the method of operation of a stationary source" that significantly "increases" its emissions of air pollution (CAA §111(a)(4), 42 USC § 7411(a)(4)).[1] That definition applies to both the PSD (CAA §169(2)(C), 42 USC § 7479(2)(C)) and Part D NSR (CAA § 171(4), 42 USC § 7501(4)) programs. The definition covers not only the addition of new emission points to existing sources

[1]The CAA does not expressly exempt even very small increases in emissions. But EPA, with court approval, has exempted nonsignificant increases from NSR. Significance levels are set out in Box 2-1. Use of the term "physical change" in the rest of this report also includes a change in the method of operation of a stationary source.

but also to at least some changes at existing emission points. (As discussed later, EPA has exempted changes that are "routine maintenance, repair, and replacement," a term whose scope is in considerable dispute.)

EPA regulations governing NSR (40 CFR 51.165-166 and 40 CFR 52.21) elaborate on the statutory definition of a modification.[2] In 2002 and 2003, EPA amended those regulations. The alterations affect only existing sources whose operations are being altered; the treatment of new sources is unchanged. The first of the revisions, published December 31, 2002 (67 Fed. Reg. 80186 [2002]), changed the rules in five ways. These changes are mainly concerned with determining whether a proposed project would "increase" emissions and with exempting from NSR some kinds of projects that were subject to NSR prior to the rule change. Portions of the 2002 rule were vacated by the D.C. Circuit Court of Appeals in New York v. EPA, 413 F.3d 3 (D.C. Cir. 2005).

EPA amended the rules again on October 27, 2003 (68 Fed. Reg. 61248 [2003]). This revision established what became known as the equipment replacement provision (ERP); it provided that some kind of replacements of equipment at existing major stationary sources would be considered routine maintenance, repair, and replacement and hence exempt from NSR. This rule never went into effect, due to a judicial stay, and was vacated by the D.C. Circuit Court of Appeals in New York v. EPA, 443 F.3d. 880 (D.C. Cir. 2006). (EPA's petition for rehearing by the entire active membership of the circuit court is currently pending.)

NEW SOURCE REVIEW PROGRAMS

The two NSR programs—the PSD program and the Part D NSR program—have two special characteristics. First, each program requires that the allowable emission level of a proposed new or modified source be based on a case-by-case evaluation of how much emission reduction can be accomplished. Second, each program gives special attention to proposed new or modified sources in or near sensitive areas; the Part D NSR program emphasizes areas that violate air-quality standards, and PSD seeks to give special protection to national parklands, such as large national parks and wilderness areas, as well as areas that have experienced substantial growth in concentrations of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM).

[2]EPA's regulations refer to a covered modification as a "major modification." In this report, we use the statutory term "modification" interchangeably with the regulatory term "major modification."

Prevention of Significant Deterioration: Evolution and Summary

The PSD program was born in the early 1970s after enactment of the CAA amendments of 1970 (Pub. L. 91-604). The amendments established the basics of today's CAA. EPA was required to establish NAAQS, and the states were commanded to write state implementation plans (SIPs) to ensure that the NAAQS were attained and maintained. EPA was also obligated to develop New Source Performance Standards (NSPS), based on levels of emissions that can be achieved using the best demonstrated technology, for categories of new and modified stationary sources whose emissions might endanger public health or welfare. A source within a category for which there are NSPS must comply when the source is constructed or physically or operationally changed in a way that increases emissions.

The 1970 amendments did not expressly stipulate whether states were required to establish measures to prevent the deterioration of air quality that is superior to the NAAQS. EPA administrator William Ruckelshaus ruled that states had no obligation to do so. However, the U.S. District Court for the District of Columbia overturned that interpretation of the Act (Sierra Club v. Ruckelshaus, 344 F. Supp. 253 [1972]). An equally divided U.S. Supreme Court eventually affirmed that decision without opinion (Fri v. Sierra Club, 412 U.S. 541 [1973]). As a result, EPA created the PSD program in 1974 to impose requirements on the construction or modification of major sources in clean air areas (39 Fed. Reg. 42510 [1974]). Congress altered and codified the program in the CAA amendments of 1977 (Pub. L. 95-95, § 127). Later, by technical amendment, Congress made clear that the PSD program, as in EPA's 1974 rules, covers modifications (Pub. L. 95-190, § 14(a)(54) [adding CAA § 169(2)(C), 42 USC § 7479(2)(C) defining the term construction to include modifications]).

In Section 160 of the CAA (42 USC § 7460), Congress articulated several goals for the PSD program, such as protection of national parks and the prevention of health and welfare effects that can occur at ambient concentrations allowed by the NAAQS (see Box 2-1). Some of these goals (e.g., to prevent transboundary air pollution) seem primarily focused on decreasing national or regional emissions loadings. Others, such as the prevention of health effects, are concerned also with local growth in emissions that may have little effect on broad regional or national emissions but which threaten the health of nearby individuals and the welfare of adjacent national parks or other national treasures.

The PSD program requires a permit for the construction or modification of a "major emitting facility" in an area to which the program applies (CAA § 165(a), 42 USC § 7475(a)) (see Box 2-2).

The program applies in every area that attains at least one of the NAAQS (Alabama Power v. Costle, 636 F.2d 323, 364-368 [D.C. Cir. 1980] [CAA

BOX 2-1
Section 160 of the Clean Air Act

The purposes of this part are as follows:

(1) to protect public health and welfare from any actual or potential adverse effect which in the Administrator's judgment may reasonably be anticipate[d] to occur from air pollution or from exposures to pollutants in other media, which pollutants originate as emissions to the ambient air[,] notwithstanding attainment and maintenance of all national ambient air quality standards;

(2) to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;

(3) to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources;

(4) to assure that emissions from any source in any State will not interfere with any portion of the applicable implementation plan to prevent significant deterioration of air quality for any other State; and

(5) to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision-making process.

§ 165(a), 42 USC § 7475(a)]). Because no area violates all the NAAQS, PSD applies nationwide. (It does not apply, however, to emissions of pollutants for which the source's locale does not attain the NAAQS; the Part D NSR program applies to those.) If a source is in one of 28 named categories, it is a major emitting facility if its "potential to emit" any regulated air pollutant is 100 tons/year or more. Otherwise, the source is covered if its potential to emit is 250 tons/year or more (CAA § 169(1), 42 USC § 7479(1)). Potential to emit generally represents the source's emissions if it is operated at maximum design capacity. A source may reduce its potential to emit by agreeing to a legally binding limit on its emissions (e.g., 40 CFR § 51.166(b)(4)). If the source agrees to a limit that reduces its potential to emit below the coverage thresholds, it is no longer a major emitting facility and is exempt from the program. Such a source is often called a synthetic minor.

BOX 2-2
Major Requirements for Obtaining a PSD Permit

A public hearing has been held on the application.

The owner or operator has shown that the proposed project would not contribute to a violation of the NAAQS or the PSD increments.

The proposed project is subject to the best available control technology for each pollutant emitted in more than de minimis amounts.

Effects of the proposed project on the air-quality-related values of Class I areas have been analyzed.

The applicant agrees to monitor the source's effects.

SOURCE: Adapted from CAA § 165(a), 42 USC § 7475(a).

A modification of a major emitting facility requires a PSD permit if it would increase the net emissions of a pollutant by a "significant amount" (see Box 2-3). Significance levels are based on the levels at which, in EPA's view, the benefits of regulation would be de minimis or where administrative necessity dictates an exemption. An applicant for a PSD permit must show

BOX 2-3
EPA Significance Levels of Emission of Criteria Pollutants

Carbon monoxide: 100 tons/year

Nitrogen oxides: 40 tons/year

Sulfur dioxide: 40 tons/year

Ozone: 40 tons of volatile organic compounds per year

Lead: 0.6 tons/year

PM_{10}: 25 tons/year

$PM_{2.5}$: 15 tons/year

SOURCE: 40 CFR § 51.166(b)(23)(i).

that the new or modified facility will, for each regulated pollutant emitted in significant amounts, limit emissions to the level achievable through use of the best available control technology (BACT). The BACT determination is made on a case-by-case basis and must be at least as stringent as whatever NSPS exist for the source's category (CAA § 169(3), 42 USC § 7479(3)). Since 1987, EPA has stated that BACT must be set with a top-down approach; that is, BACT should be set at the most stringent level achieved by a source in the same category unless the applicant can show that level to be unachievable (61 Fed. Reg. 38250, 38272-38273 [1996], which proposes to incorporate this approach formally into EPA's rules).

The applicant also must show that the new or modified source, in combination with emission increases from other sources, will comply with a system of increments that limit permissible growth in air pollution above the baseline concentrations—the concentrations that existed in an area when the first application was filed for a PSD permit there (CAA § 169(4), 42 USC § 7479(4)). Increments exist for NO_2, SO_2, and PM (see Box 2-4).[3] The size of the increments varies with an area's classification as Class I, II, or III. The largest increments, and hence the least stringent restrictions on growth, apply in Class III areas. The tightest increments apply in Class I areas. This tends to encourage new sources to stay away from these areas or to install strict control technology if they wish to locate near Class I areas.

Congress designated 158 large national parks and wilderness areas existing in 1977 as mandatory Class I areas. Most Class I areas are west of the Mississippi River; nearly one-fourth of them are in Utah, Arizona, New Mexico, or Colorado (Oren 1989). The remainder of the nation initially was classified as Class II. States and Indian tribes are allowed to redesignate areas as Class I or (except for some parklands) as Class III. The states have not redesignated any areas. To date, several Indian tribes have designated their reservations as Class I. No areas have been designated as Class III, and the many national parks and wilderness areas created since 1977 (e.g., those created by Congress in 1980 in Alaska) have remained Class II areas.

About 39 states have incorporated the PSD program into their SIPs. In some of the remainder (such as New York), EPA runs the program itself but delegates its responsibility to the state for most day-by-day decisions; in the rest, EPA runs the program directly.

In 2001, EPA estimated that PSD control-technology determinations from 1997 to 2001 eliminated a potential increase of 1.4 million tons of air

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[3]The SO_2 increments are stated in the CAA. The statute also established increments for total suspended particulates (TSP). EPA, pursuant to Congressional direction, has since replaced those increments with equivalently strict increments. The statute imposes an obligation on EPA to establish increments or equivalent measures for other criteria pollutants (CAA § 166, 42 USC § 7476). This mandate has been used to force EPA to set increments for NO_x, but there has been no effort to compel the agency to meet section 166 for other pollutants.

BOX 2-4
PSD Increments

Class I	*Increment (µg/m3)*
SO_2	
Annual arithmetic mean	2
24-hr maximum	5
3-hr maximum	25
NO_2	
Annual arithmetic mean	2.5
PM_{10}	
Annual arithmetic mean	4
24-hr maximum	8
Class II	
SO_2	
Annual arithmetic mean	20
24-hr maximum	91
3-hr maximum	512
NO_2	
Annual arithmetic mean	25
PM_{10}	
Annual arithmetic mean	17
24-hr maximum	30
Class III PSD increments	
SO_2	
Annual arithmetic mean	40
24-hr maximum	182
3-hr maximum	700
NO_2	
Annual arithmetic mean	50
PM_{10}	
Annual arithmetic mean	34
24-hr maximum	60

SOURCE: 40 CFR § 51.166(c).

pollution per year. About 822,000 tons of these reductions, or about 60%, were NO_x, and about 420,000 tons, or about 30%, were SO_2. Some 90% of such benefits are believed to have occurred at new electricity-generating facilities (EPA 2001). These estimates do not take into account benefits that occur when source operators limit emissions so that the PSD permit process will not apply.

Part D New Source Review

The 1977 CAA amendments included an NSR program for nonattainment areas (those whose air quality does not meet the NAAQS). The program also applies to major stationary sources of volatile organic compounds (VOCs) in the ozone (O_3) transport region in the Northeast even if they are in attainment areas (CAA § 184(b)(2), 42 USC § 7511c(b)(2)), because emissions of VOCs contribute to violations of the O_3 ambient standards.

In 1970, Congress required attainment of the primary standards no later than 3 years after approval of a state's SIP, with a possible 2-year extension. It became clear that timetable would not be met, and in late 1976, EPA published an interpretive ruling that outlined conditions under which new and modified major sources would be allowed in areas that failed to attain the air-quality standards on schedule (41 Fed. Reg. 55524 [1976], codified as 40 C.F.R. § 51, Appendix S). The purpose of the ruling's conditions was to allow economic growth while minimizing the effect of new and modified sources on air quality in areas that had failed to meet the standards. Congress codified the program (known as Part D NSR because it is included in that part of the CAA) in 1977 as part of a renewed effort to bring about attainment of the NAAQS (Pub. L. 95-95, § 129). Part D NSR requires that an operator obtain a permit before construction or modification of a major stationary source (see Box 2-5). Generally, a major stationary source is defined as one that emits or has the potential to emit any air pollutant at more than 100 tons/year (CAA § 302(j), 42 USC § 7602(j)). (The quantity is lower for NO_x and VOCs in O_3 nonattainment areas that are classified as in "moderate," "serious," "severe," or "extreme" violation [e.g., CAA §182(c), 42 USC § 7511a (c)]). A major source is covered only to the extent that its emissions would contribute to nonattainment of a NAAQS. Thus, if a proposed source would emit two pollutants and the area violates the NAAQS for only one, the source is covered by Part D NSR for that pollutant and by PSD for the other. As under the PSD permit, a modification is covered if it would result in an increase in pollutants that is "significant"—that is, at least exceeding the levels in Box 2-1.

To obtain a permit to construct or modify, the applicant must show that the new or modified source will emit at the lowest achievable emission rate (LAER), defined in the statute as the more stringent of the tightest emission

BOX 2-5
Part D NSR Permit Requirements

- The applicant must obtain emission offsets (or, in an area in an economic development zone, fit within a margin for growth specified in the SIP).
- The applicant must show that all sources it owns or operates in the state are in compliance.
- EPA must not have found that the area is not implementing its SIP.
- The benefits of the proposed source significantly outweigh the environmental and social costs.

SOURCE: Adapted from CAA § 173, 42 USC § 7503.

limit achieved in practice or the tightest SIP limit for that category of source (unless the operator can show that level not to be achievable) (Section § 173 (a)(2), 42 USC § 7503(a)(2)). The applicant must also (except in a few cases) obtain emission offsets—reductions in emission from other sources that are enforceable and not otherwise required—so that the construction or modification will not disrupt progress toward attaining the NAAQS. In areas classified as in serious, severe, or extreme nonattainment of the O_3 standard, the offset must be greater than 1-to-1.

The Part D NSR program has been incorporated by the states into their SIPs for all nonattainment areas. Thus, in contrast with the case of PSD, there is no area where EPA runs the program.

NEW SOURCE REVIEW IN THE FRAMEWORK OF THE CLEAN AIR ACT

The role of NSR can best be appreciated by outlining the other mechanisms in the act that control emissions from stationary sources:

- Under section 110 (42 USC § 7410), each state must prepare and enforce a SIP for the NAAQS pollutants. The SIP must demonstrate that it will result in attainment and maintenance of the primary NAAQS by a given deadline and of the secondary standards as expeditiously as practicable. If an area is in attainment, its SIP must show that the standards will be maintained. SIPs are required to include "minor" NSR programs that control emissions from the construction and modification of sources that are too small to be covered by the NSR programs. SIPs may regulate new and modified major stationary sources of air pollution more strictly than NSR, although this does not happen often.

- Under Section 111 (42 USC § 7411), EPA establishes NSPS for categories of stationary sources that emit air pollution that may endanger public health or welfare. NSPS emission limits are based on the degree of emission limitation that can be achieved by a source in a category through use of the best demonstrated technology. NSPS (with an exception not relevant here) apply only to sources that commence construction or modification after the NSPS for the category are proposed (CAA § 111(a)(2), 42 USC § 7411(a)(2)). As summarized above, BACT and LAER emission limits under the NSR programs must be at least as stringent as NSPS. Thus, NSPS generally do not require control in excess of NSR.[4]
- Section 112 (42 USC § 7412) requires EPA to establish categorywide standards to limit emissions of hazardous air pollutants (HAPs). Those standards are known as National Emissions Standards for Hazardous Air Pollutants (NESHAPs). Because some HAPs are subsets of PM and VOCs (precursors to ozone formation), this requirement results in regulation of pollutants covered by the NAAQS. The requirement can potentially lead to regulation of new and modified sources that is stricter than NSR.
- Section 169A (42 USC § 7491) establishes a national goal of eliminating human-caused degradation of visibility in mandatory Class I areas (national parks and similar areas) where visibility is an air-quality-related value. (Out of the 158 mandatory Class I areas, 156 fall into this category.) The program requires EPA to establish requirements for implementing this goal and to mandate the installation of the best available retrofit technology (BART) on some categories of large sources constructed in the period of 1962 and 1977. In 1980, EPA established rules for regulating visibility degradation that can be reasonably attributed to one or a few large stationary sources (40 CFR § 51.302). The program includes regulation of major new sources that are in nonattainment areas (and are therefore exempt from PSD) but might damage visibility in Class I areas (40 CFR § 51.307). The rules in effect fill a gap in NSR as it had been interpreted by the courts. The agency has also promulgated rules for combating regional haze, which is caused by many sources. These rules set out criteria for states to use in making BART determinations. States need not make BART determinations to the extent their programs are "better than BART."[5] There are two main categories of such programs. The first consists of programs in states subject to the Clean Air Interstate Rule (CAIR) summarized below. In these states,

[4]There can be exceptions. NSPS can cover sources that are not large enough to be "major sources" covered by NSR.

[5]The "better than BART" provisions are presently being challenged in court.

BART does not apply to electricity-generating facilities. The states subject to CAIR are in the East and Midwest, so BART's application to electricity-generating facilities is likely to be largely confined to the West. The second consists of programs that adopt the cap-and-trade initiative established by the Western Regional Air Partnership (WRAP) as a result of the recommendations of the Grand Canyon Visibility Transport Commission; five states have indicated that they will adopt this initiative, which sets up a cap-and-trade program that will apply if emissions in 2018 exceed projections.[6]

Several very significant cap-and-trade programs have been established to limit emissions from electricity-generating facilities. Those programs assign a reduction target to the nation or a region. Regulated sources are granted allowances in proportion to their historical emissions and are allowed to trade allowances so that the cap can be achieved at the lowest cost. Sometimes sources make early reductions in emissions to enable them to "bank" allowances for use in future years. New sources, and existing sources that increase emissions, must generally obtain allowances from other sources covered by the overall cap.

- Electricity-generating facilities are subject to the acid rain program of Title IV, enacted as part of the 1990 CAA amendments. Generally, an electricity-generating source is issued allowances for SO_2 that equals 1.2 lb per million British thermal units multiplied by the source's annual average heat input (a measure of the source's use) for the period 1985-1987. Each allowance enables its holder to emit a ton of SO_2. This program phases in by 2010 a limit of 8.97 million annual allowances. (Because sources often made early reductions and banked the saved allowances, annual emissions will be over 8.97 million tons until several years later.) The program also includes requirements for controlling NO_x emissions from electricity-generating facilities.
- Section 110(a)(2)(D) requires each state's SIP to prevent emissions that "contribute significantly" to nonattainment of the NAAQS in other states or that interfere with another state's PSD or visibility protection program. That has led to the formation of two programs:

—In 1998, EPA found that NO_x emissions in 22 (later reduced to 19) states interfered with attainment of the O_3 NAAQS in other states. EPA ordered that the states cut back NO_x emissions by 28%, or more than 1 million tons/year, during the April-October period when O_3 concentrations are at their highest. (This order is referred to as the "NO_x SIP call.") That target represents the reduction that EPA found could be made through

[6]EPA is in the process of revising its rules to make it possible for states to adopt the program.

cost-effective measures (those costing less than $2,000/ton of emissions eliminated) (Michigan v. EPA, 213 F.3d 663 [D.C. Cir. 2000]). The states have followed EPA's suggestion to establish cap-and-trade programs to accomplish the reduction at the lowest cost. Because existing electricity-generating facilities are the most cost-effective sources to control, the brunt of the reductions falls on them.

—In March 2005, while this report was being prepared, EPA promulgated CAIR. EPA found that emissions of SO_2, NO_x, or both from 29 eastern and midwestern states interfere with attainment and maintenance of the air-quality standards for O_3 and/or PM. (For a map of the affected states under the promulgated rule, see EPA [2005a]. The rule has since been revised to include New Jersey and Delaware for PM [71 Fed. Reg. 25287 (2006)]). EPA expects that, as with the NO_x SIP call described above, the states in the CAIR region will each adopt a cap-and-trade program directed at lowering emissions from electricity-generating facilities. Emissions of SO_2 from such facilities in these states will be capped at 3.9 million tons in 2010 and at 2.7 million tons in 2015. (The banking of allowances by sources through early reductions will keep emissions above 2.7 million tons/year for some years after 2015; see Chapter 6.) EPA (2004b) estimated that these caps will result in a reduction of 3.6 million tons of SO_2 emissions in 2010 and an additional reduction of 2 million tons/year when the rules are fully implemented in 2015 (about 70% below 2002 emission levels). Emissions of NO_x from electricity-generating facilities are capped at 1.6 million tons in 2010 and 1.3 million tons in 2015. EPA estimated that NO_x emissions would be reduced by 1.5 million tons in 2010 and by 1.8 million tons when fully implemented in 2015 (about 65% below 2002 emission levels). As with the 1998 NO_x SIP call, the emission goals are based on what can be done through control technologies that are cost-effective compared to other regulatory controls. CAIR has been challenged in the courts, but the program will remain in effect during the litigation, because of the D.C. Circuit's recent refusal to order a stay of the program. EPA has considered and rejected several petitions to reconsider some aspects of CAIR. Nevertheless, the challenges to CAIR mean that its prospects are somewhat uncertain.

- EPA in 2005 also launched a program, known as the Clean Air Mercury Rule (CAMR), to reduce emissions of mercury (Hg) with a cap-and-trade approach for coal- and oil-fired electricity-generating facilities. Beginning in 2010, allowances for 38 tons/year will be distributed by EPA. Allowances will be reduced to 15 tons beginning in 2018. (Present annual emissions are 48 tons/year [EPA 2005b].) However, because of the banking of emissions, annual emissions are expected to remain over 15 tons for some time after 2018 (EPA 2005c). The caps are not expected to cause electricity-generating facilities to adopt strategies that lower national SO_2 and NO_x

emissions beyond reductions resulting from other programs (Palmer et al. 2005). (We are not expressing any judgment about whether the agency chose the caps correctly.) Although Hg, as a pollutant listed under section 112, is not regulated by NSR, we mention the Hg-control program because EPA's air-quality modeling includes CAMR in its assessment of future emissions under the CAIR program.

CAIR and CAMR both stem from the Clear Skies proposal first made by the Bush administration in 2002 and renewed in 2003 and 2005. Clear Skies (109th Cong., S. 131) would cap SO_2 emissions at 4.5 million tons in 2010—half what is allowed by the acid-rain program of Title IV—and at 3 million tons in 2018. That would mean a 73% decrease from 2000. Clear Skies would reduce NO_x emissions from 5 million tons in 2000 to 2.1 million tons in 2008 and 1.7 million tons in 2018—a two-thirds reduction. The Clear Skies legislation would also codify the trading program proposed by WRAP to prevent degradation of visibility in the Southwest.

Clear Skies has provoked opposition from the electricity-generating sector and other industrial groups, which say that the goals are too stringent, and from environmental groups, which contend that they are too lax. Environmentalists have tended to favor Senator James Jeffords's proposed Clean Power Act (109th Cong., S. 150), which calls for more extensive and quicker emissions cuts. For instance, the Clean Power Act would cap SO_2 emissions at 2.25 million tons in 2010 compared with Clear Skies' proposal of a 4.5-million-ton cap in 2010 and a 3-million-ton cap in 2018.

Neither of those proposals has been endorsed by committee or reached the floor of the Senate or the House of Representatives, and their futures are unclear. In early 2005, proponents of Clear Skies failed to persuade a majority of the Senate Committee on Environment and Public Works to report it to the Senate floor.

Cap-and-trade programs, such as CAIR, can in theory reduce emissions from individual new sources beyond what is achieved by other programs of the CAA such as NSR. That can occur because new sources must purchase allowances from existing sources. If the emission cap is very tight, the cost of allowances will be high and operators of new sources might reduce their emissions lower than what NSR would require rather than purchase allowances. EPA, however, has not projected such an effect of CAIR except to the extent that the presence of a cap encourages investment in natural gas to reduce SO_2 emissions.

For similar reasons, it is unlikely that Clear Skies would reduce emissions from individual new sources. In addition, Clear Skies would exempt new electricity-generating facilities, and under certain conditions, it would exempt some modifying electricity-generating facilities from most NSR requirements.[7] It is therefore unlikely that Clear Skies would result in emission limits at individual new or modified sources that are more stringent than those achieved when NSR is triggered at the same sources. (We are not expressing any judgment about the overall environmental effects of Clear Skies.)

Concerns About Modifications

The controversy about EPA's changes in its rules regarding modifications stems from the CAA's differentiation between new and existing stationary sources. NSR, as mentioned previously, requires new sources to meet strict technology-based standards as well as show that they will not damage air quality. In contrast, most existing sources (those that do not go through reconstruction or modification) need generally accomplish only as much emission reduction as is necessary to enable their locales to meet and maintain the NAAQS set by EPA; even those existing sources that are subject to the technology-based standard of reasonably available control technology (RACT) need not control as much as new sources.

That differentiation has attracted debate. Supporters assert that it is justified because new sources can most easily incorporate the latest pollution-control technology. In addition, supporters argue, tight regulation of new sources is the best way to ensure against future air-pollution problems and to guarantee that the turnover of capital stock results in reduced emissions. Critics argue, by contrast, that the differentiation between old and new sources encourages industry to keep older, heavily polluting sources on line longer instead of building new, cleaner sources, thus potentially hindering environmental progress. Emission-trading advocates urge that it would be preferable to allow trading between sources, whether new or existing, to achieve the needed emission reductions. Opponents of this suggested change argue that a trading approach by itself would not be sufficient to protect especially vulnerable areas from large new sources.

Alterations at existing plants pose an especially difficult question. Plants where physical or operational changes are occurring occupy a middle ground between new and existing sources. Inserting state-of-the-art technology when a source experiences a change is, at least sometimes, more problematic than including such controls in a new plant. Plants where changes are occurring may often be better targets for regulation than unaltered existing sources. For instance, changes in existing plants, if unregulated by NSR, might keep such plants on line longer and slow their replacement with new, cleaner facilities. (On the other hand, it is also possible that regulat-

[7]New electricity-generating facilities locating within 50 km of a Class I area, such as a national park, would have to conduct an analysis of the air-quality effects on the park.

ing such changes will discourage them, thus delaying clean-up.) Slowing replacement of existing plants may give them a competitive edge over new plants, therefore perpetuating high emissions. Furthermore, adding control technology at an existing source when it is undergoing modification may well be easier than installing such controls at an existing source that is not undergoing modification. (For instance, a boiler modification will take a unit off line and thus make it possible to install, for example, an electrostatic precipitator with less disruption than trying to retrofit a unit not undergoing modification.) Those arguments are reflected in the different viewpoints about how the term modification should be defined.

Environmental groups argue that a broad definition is needed because of the following:

- Health and the environment may be endangered when existing sources increase emissions.
- Narrowing the definition would interfere with enforcement actions that are permanently lowering emissions and thus bettering air quality.
- Congress intended a broad definition as a way of ensuring that older sources eventually would have to install the up-to-date pollution controls.
- A narrow definition of the term "modification" would allow renovations that permit existing sources, particularly electricity-generating facilities, to remain in operation indefinitely. A broader interpretation would discourage those renovations and instead lead to replacing the plants with new capacity that would be far cleaner than existing plants.

Industry groups counter by saying that a narrower definition is appropriate because of the following:

- Many projects that would be covered under a broad definition do not increase emissions and in fact reduce them by replacing older equipment with less-polluting equipment.
- The programs are complex, and it is difficult to determine whether an NSR permit is required for a given change.
- Preparing a permit application, obtaining needed offsets, waiting for EPA or state officials to process the application, and complying with BACT for the modification may be expensive and burdensome. The process of reviewing the application takes additional time that slows completion of the project.
- Other programs, such as caps on emissions from electricity-generating facilities, can constrain emissions at a lower cost than a stringent NSR program.

Environmental Protection Agency's 1980 New Source Review Rules and Their Interpretation

Congress's 1977 codification of PSD and Part D NSR made it necessary for EPA to revise its rules governing the programs. That was done through a rulemaking in 1978. In 1979, the D.C. Circuit Court of Appeals in the Alabama Power decision overturned several important portions of the rules. EPA then promulgated new rules in 1980 (45 Fed. Reg. 52676 [1980]), and these rules are largely still in effect.

The 1980 rules covered both the "physical or operational change" and the "any increase in emissions" aspects of the congressional definition of modification. The term physical or operational change was defined to exclude "routine maintenance, repair, and replacement," a term that the regulations do not elaborate on.[8]

An increase in emissions was defined in terms of an increase in actual annual emissions, taking into account contemporaneous increases and decreases in emissions. Emissions before the change were specified to mean the average emissions at the source over the previous 2-year period unless the source could show that a different consecutive 2-year period was more representative of normal source operation.

The 1980 regulations subjected postchange emissions to a special meaning of the term "actual emissions." For units that have not entered normal operation, the term actual emissions was defined as equal to the unit's potential to emit. Thus, for a unit that had not entered normal operations, the 1980 rules covered a physical or operational change as a modification if the source's postchange potential to emit exceeded the source's prechange actual emissions by a significant amount. That is commonly referred to as the "actual-to-potential" test. Because a source's potential to emit is often greater than its actual emissions, an actual-to-potential test tends to lead to coverage of a project by NSR. The plant owner can escape coverage only by making a binding promise never to increase actual emissions significantly over prechange emission levels.

The Puerto Rican Cement case illustrates the workings of the test. Puerto Rican Cement had been running its kilns at 60% capacity and emitting 1,100 tons of NO_x and 1,340 tons of SO_2 per year. The company planned to build a new cement kiln. If operated at the same 60% capacity as the older unit, the new kiln would emit 578 tons of NO_x and 850 tons of SO_2 per year—a decrease from previous levels. But if the unit operated at full allowable capacity, it would emit 1,250 tons of NO_x and 1,927 tons

[8]The statute does not expressly exclude routine maintenance. Presumably, as recently suggested by the D.C. Circuit Court of Appeals in *New York v. EPA*, 440 F.3d 880 (D.C. Cir. 2006), the exemption is based on the inherent power of an agency to exclude from regulation those activities that have a "de minimis" effect.

of SO_2 annually. This represented its potential to emit. EPA compared the latter numbers with the prechange annual tonnages of 1,100 and 1,340, respectively, and ruled that construction of the new kiln would increase emissions within the meaning of its 1980 regulations and that, therefore, a PSD permit was required.

The U.S. Court of Appeals for the First Circuit upheld that approach in a decision written by Judge Stephen Breyer (*Puerto Rican Cement v. EPA*, 889 F.2d 292 [1st Cir. 1989]). The court rejected the company's argument that EPA's approach was arbitrary because it would discourage modernizations that decreased emissions at the present rate of use. Instead, the court reasoned EPA had decided to focus on the possibility that the introduction of new, more-efficient equipment would lead a company to produce at higher levels and therefore increase emissions. Hence, the company needed a PSD permit for the new kiln unless it was willing to reduce the unit's potential to emit by making a binding commitment never to increase emissions by a significant amount over prechange emission levels.

The court acknowledged, however, that in some situations, EPA's actual-to-potential test might be unreasonable. For instance, the court suggested, it might be irrational to assume that a replaced peak-load generator would run at full capacity. That observation became important in the Wisconsin Electric Power (WEPCO) decision (*Wisconsin Electric Power v. Reilly*, 893 F.2d 901 [7th Cir. 1991]), which involved a so-called life-extension project at WEPCO's Port Washington plant. The plant consisted of five coal-fired steam-generating units placed in service in the period 1935-1960. Over time, each had deteriorated from its design capacity of 80 megawatts (MW), and one unit had been shut down because of the risk of catastrophic failure. The aim of the project was to keep the units operating until 2010 beyond their original 1992 retirement date. As part of the project, WEPCO planned to replace air heaters, steam drums, and other major components on four units.

EPA ruled that a PSD permit was required on the grounds that the project did not constitute routine maintenance, repair, and replacement and that it would increase emissions according to the actual-to-potential test. Hence, the dispute involved both the physical change and the emissions-increase aspect of modification. The electricity-generating facility appealed to the U.S. Court of Appeals for the Seventh Circuit, which decided for EPA on the physical-change issue, although holding that the project would not increase emissions for NSR purposes. WEPCO argued that "like-kind" changes—the replacement of existing equipment—do not constitute physical changes, because they do not alter the plant. EPA countered that the WEPCO project was unprecedented: "WEPCO did not identify, and EPA did not find, even a single instance of renovation work at any electricity-generating station that approached the Port Washington life extension project in nature, scope or extent" (*Wisconsin Electric Power v. Reilly*, 893. F.2d 901 [7th Cir. 1991], p. 911). The court agreed with EPA, saying that a contrary reading would contravene Congress's intent to stimulate the advance of pollution-control techniques by requiring controls when generating systems are extensively replaced. The court also rejected WEPCO's argument that its project qualified as routine maintenance, repair, and replacement under EPA's rules. The court noted that EPA stated that it "makes a case-by-case determination by weighing the nature, extent, purpose, frequency and cost of the work, as well as other relevant factors, to arrive at a common-sense finding." In this case, EPA had relied on the magnitude of the project, the exclusion from the project of repetitive maintenance normally performed during outages, and the lack of similar projects at other power plants. The court held that EPA could use these factors and that EPA had reasonably applied them to the facts of the case. The court noted that WEPCO had stated that its project involved a life extension and that the project would involve items that normally would occur only once or twice during a unit's expected life cycle; this, according to the court, supported EPA's finding that the project did not constitute routine maintenance, repair, and replacement.

But the court rejected EPA's argument that the project would increase emissions within the meaning of the NSR programs. The court distinguished between the NSPS program and the NSR programs. In the NSPS program, the court explained, EPA's regulations call for a comparison of prechange and postchange emission rates, as expressed in kilograms per hour, at maximum physical capacity (40 CFR § 60.14(b); 57 Fed. Reg. 32314, 32316 [1992]). Because such an increase had occurred at three of the five units, the project needed to comply with the NSPS for the source's category for those units.

The court held that, in contrast, actual annual emissions must increase for a project to be subject to NSR. The court overturned EPA's use of the actual-to-potential test to determine whether an increase would occur. The court found it unreasonable for EPA to disregard past operating conditions at the plant and to regard the units as having never entered normal operation. The Puerto Rican Cement case was distinguished as involving a new unit at an existing site, unlike a "like-kind replacement" of equipment at an existing unit. The latter, the WEPCO court ruled, resembled the peak-operating-unit example in the Puerto Rican Cement decision.

EPA responded to the decision with what is known as the WEPCO rule (57 Fed. Reg. 32314 [1992]). This rule excludes electricity-generating facilities from the actual-to-potential test as long as the proposed project neither adds a new unit nor replaces an existing one. Instead, the facility may compare prechange actual annual emissions with postchange projected annual emissions. If the electricity-generating facility concludes that there would be no significant increase in emissions, thereby exempting the project from NSR, it must submit documentation of its emissions for 5 years after the change to confirm that a significant increase in emissions did not occur as a result of the project. In addition, the calculation of postchange emissions may exclude emission increases attributable to increased market demand rather than to the physical or operational change; this exclusion can apply to increases that legally and physically would have been feasible without the change.

EPA also altered the definition of prechange emissions for electricity-generating sources. Before the alteration, prechange emissions were calculated by averaging emissions over the 2 years before the change unless the source could show that a different 2-year period was more representative. EPA changed the rule to allow electricity-generating sources to use any consecutive 2-year period in the preceding 5 years. In the preamble to the WEPCO rule, EPA promised guidance on what is "routine maintenance, repair, and replacement" (57 Fed. Reg. 32326 [1992]). Instead, as discussed later, EPA in 2003 issued a rule defining certain activities as exempt from NSR because they did not constitute physical or operational changes.

Finally, the 1992 rule excluded from the definition of physical or operational change, and hence from NSR review, pollution-control projects (PCPs) that "do not render the unit less environmentally beneficial." In that way, EPA asserted, the prospect of NSR review would not influence an electricity-generating facility's choice of how to cut emissions to comply with the acid-rain-control program that had been adopted by Congress in 1990. This exclusion for PCPs was later invalidated in *New York v. EPA*, 413 F.3d (D.C. Cir. 2005).

Those changes were confined to electricity-generating facilities because EPA believed that it did not have enough knowledge of other source categories to allow the changes to be extended to them. However, EPA later issued guidance that extended the PCP exemption to other source categories (67 Fed. Reg. 80232 [2002]).

NEW SOURCE REVIEW REFORM PROJECT

EPA also launched in 1992 an effort to simplify and streamline its NSR rules. It formed a subcommittee of its Clean Air Act Advisory Committee composed of representatives of states, environmental groups, and industries. For several years, the subcommittee members discussed possible changes in the rules. It did not achieve consensus, but in EPA's view, its existence helped to make clear which issues were important.

In 1996, EPA proposed a package of changes to the NSR rules (61 Fed. Reg. 38250 [1996]). The proposal discussed the topics later covered in the 2002 rule (for example, expanded use of the actual-to-projected-actual method), although the 2002 rule differs in important respects. The proposed changes also included elements sought by environmental groups, such as greater protection of national parks and codification of the longstanding top-down method of determining what constitutes BACT.

The 1996 proposal generated a great deal of comment. In 1998, EPA issued a "notice of availability" in which it expressed reservations about some of its proposed changes (such as the enforceability of the actual-to-projected-actual approach and of allowing sources to exclude emission increases due to demand growth in projecting future emissions) and solicited comment on possible alternatives (63 Fed. Reg. 39857 [1998]). EPA did not complete the rule-making process before the end of the Clinton administration in January 2001.

Enforcement Initiative

EPA's 1996 proposal did not discuss which changes constitute routine maintenance, repair, and replacement. That issue became increasingly important in the late 1990s. EPA, often joined by environmental groups and northeastern states, asserted that some large electricity-generating plants had been undertaking modifications without obtaining NSR permits. According to EPA, those projects allow electricity-generating facilities to run the altered plants at higher capacity and therefore to increase emissions. In addition, EPA claimed that the projects allow the plants to remain on line longer instead of being replaced by new, cleaner plants that would decrease emissions substantially from present levels. The agency contended that, under the multifactor test used in WEPCO, the electricity-generating facility projects did not qualify for the routine-maintenance exemption and instead constituted physical or operational changes that increased emissions.

Electricity-generating facilities, in contrast, argue that such projects should be considered to constitute routine maintenance, repair, and replacement and therefore exempt from NSR. The projects, according to owners of electricity-generating facilities, have always been undertaken in the industry and are necessary to ensure adequate and reliable generating capacity. A report by the National Coal Council states that coal-fired power plants more than 20 years old—a category that accounts for two-thirds of electricity generation from coal—have been derated (reduced in power-generating capacity) and that a substantial amount of generation capacity (about 20,000 MW) could be regained by addressing the causes of derating (EPA 2001).

EPA brought enforcement actions against electricity-generating facilities, alleging that the companies had undertaken major modifications without obtaining required NSR permits. Those actions and their status as of August 2005 are listed in Table 2-2. In addition, EPA brought administrative enforcement actions against the Tennessee Valley Authority (TVA) and WEPCO. The action against TVA eventually was judicially invalidated on procedural grounds (Tennessee Valley Authority v. Whitman, 336 F.3d 1236 [11th Cir. 2003]); environmental groups and North Carolina are currently pursuing their own actions against TVA. Both of the suits brought by environmental groups have been dismissed by the district courts on procedural grounds and are presently on appeal.

Several of the actions have been settled, as shown in Table 2-3.[9] As the table shows, the settlements, when fully implemented in 2010-2015, will reduce SO_2 emissions by more than 650,000 tons/year and NO_x emissions by about 250,000 tons/year. (It is possible that some of these reductions might have been required by other programs under the CAA, such as the 1998 NO_x SIP call, although in many cases, the settlements brought about the reductions sooner.) Each settlement agreement requires the source to surrender SO_2 emission allowances annually. (These surrenders would not have been required by other programs.) Surrendered allowances are retired by EPA, and thus become unavailable for use by other sources. Similarly, the required reductions in NO_x may not be used to generate NO_x credits that can be sold to other sources.

Generally, the number of allowances surrendered annually equals the number of tons by which the settlement reduces the source's allowable SO_2 emissions. There are two exceptions. First, if the source had more allowances than its presettlement emissions, it must surrender the surplus allowances in addition to the allowances represented by the emission reductions required by the settlement. If the settlement would reduce a source's allowable emissions below its annual allowances, then the company need surrender only the difference between presettlement emissions and its allowances. The principle, therefore, is that a source need not surrender allowances that are necessary to keep it in compliance with cap-and-trade programs. The Virginia Electric and Power Company (VEPCO) settlement summarized below is an example of this.

The surrender of allowances in effect reduced allowable emissions below those permitted by the Title IV acid-rain program. The number of allowances surrendered will probably be reduced under CAIR, because that program considerably decreases the amount of SO_2 that can be emitted under an allowance, so the settling sources will need to keep their allowances to be in compliance. (The settling sources, as well as those against which enforcement actions are pending, are all in the CAIR region.) The same will be true if Clear Skies is enacted.

Table 2-3 also shows estimates of the capital cost of the required reductions. These costs are stated in dollars as of the date of the settlement, and

[9]In 2000, EPA reached an agreement in principle to settle its action against Cinergy, Inc; the agreement has not been incorporated into a consent agreement, so litigation between the electricity-generating facility and EPA continues.

TABLE 2-2 Pending NSR Enforcement Actions Against Coal-Fired Power Plants (as of August 2005) by Date of Filing

Case Title (District Court) Judge	Date Filed
United States v. Cinergy Corp., et al. (S.D. Ind.) Judge McKinney	November 1999
United States and State of New York, et al. v. American Electric Power Service Corp. ("AEP"), et al. consolidated with Ohio Citizen Action, et al. v. AEP, et al. (S.D. Ohio) Judge Sargus	November 1999
United States v. Georgia Power Co. and Savannah Electric and Power Co. (N.D. Ga.) Judge Carnes	November 1999
United States v. Alabama Power Co. (N.D. Ala.) Judge Bowdre	November 1999; refiled in N.D. Ala. January 2001
United States v. East Kentucky Power Cooperative	January 2004
United States v. Duke Energy Corp. (M.D. N.C.) Judge Bullock; Environmental Defense v. Duke Energy Corp., cert. granted sub. nom., No. 05-848 (May 15, 2006)	December 2000

SOURCE: Adapted from EPA, unpublished material, 2005.

so are not discounted to reflect the value of postponing an investment for several years. Moreover, the cost figures are not annualized; therefore, they cannot be used to generate cost-effectiveness numbers. According to EPA enforcement personnel, the costs of the reductions are about $500/ton for SO_2 and $900-3,000/ton for NO_x (EPA 2004c). Those costs are comparable with those for installing BACT generally.

The settlement between EPA and VEPCO illustrates the kind of steps that an agreement to end the enforcement litigation may involve. The company has committed itself to, among other things, installing scrubbers on

Utility Defendants	Status
Cinergy Corp., Cincinnati Gas and Electric Co., PSI Energy, Inc.	Permission to appeal from preliminary district court decision granted July 2006
American Electric Power Service Corp., Appalachian Power Co., Cardinal Power Co., Central Operating Co., Columbus Southern Power Co., Indiana Michigan Power Co., Ohio Power Co.	Liability trial July 2005
Georgia Power Co., Savannah Electric and Power Co. (Southern Co. operating subsidiaries)	Judge held, awaiting final decision in *TVA v. EPA*
Alabama Power Co. (Southern Co. operating subsidiary)	Stay lifted June 2004; liability trial as to Miller plant scheduled for March 2006; remainder undergoing court-ordered mediation; court held in June 2005 that emissions increase for non-Miller plants would be measured on the basis of "maximum hourly emission rate"
East Kentucky Power Cooperative	Answer filed June 2004; in settlement negotiations
Duke Energy Corp.	Final judgment issued for defendants by stipulation April 15, 2004, affirmed by 4th Circuit, May 2005

70% of its coal-fired generation capacity. That will reduce SO_2 emissions by 176,500 tons per year by 2012. The company will also install by 2013 selective catalytic reduction technology on 67% of its coal-fired-generation capacity, thereby reducing annual NO_x emissions by 66,000 tons more than other then-existing EPA programs required. In addition, the company will surrender to EPA 45,000 allowances per year beginning in 2012 (EPA 2003a). (As mentioned above, the number of allowances surrendered will probably be reduced by CAIR for sources located in the CAIR region.) Settlements can affect emissions significantly in an area. A settlement by

TABLE 2-3 Summary of Expenditures and Emission Reductions Resulting from Settled NSR Enforcement Actions

Company	Capital (millions of dollars)	Penalty (millions of dollars)	Environmental Projects (millions of dollars)	NO_x Tons Removed Annually	SO_2 Tons Removed Annually	Date Consent Decree Lodged
VEPCO	1,200	5.3	13.9	61,651	176,545	April 2003
WEPCO	600	3.2	20.0	31,770	65,053	April 2003
TECO	1,000	3.5	11.0	53,000	70,000	February 2000
PSEG	330	1.4	6.0	18,273	35,937	January 2002
SIGECO	30	0.6	2.5	4,232	6,384	June 2003
Alcoa, Inc	330	1.5	2.5	15,482	52,899	April 2003
Santee Cooper, COOPER	400	2.0	4.5	29,735	39,351	February 2004
DMG, IL Power	350	9.0	15.0	14,706	37,201	March 2005
Ohio Edison	1,100	8.5	25.0	31,050	171,500	March 2005
Totals	5,340	35.0	100.4	259,899	654,870	

ABBREVIATIONS: DMG, Dynegy Midwest Generation; PSEG, Public Service Enterprise Group; SIGECO, Southern Indiana Gas and Electric Company; TECO, Tampa Electric Company; VEPCO, Virginia Electric and Power Company; WEPCO, Wisconsin Electric Power Company.

SOURCE: EPA 2004b; EPA, unpublished material, 2005.

EPA and New Jersey with an electricity-generating plant on the outskirts of Trenton and another in Jersey City will reduce SO_2 and NO_x emissions in the state by 19% and 5%, respectively, by 2012 (EPA 2002a).

EPA enforcement officials have asserted that the cases they are currently pursuing could reduce annual SO_2 and NO_x emissions in 10 years by 1,750,000 tons and 629,000 tons, respectively (EPA 2004c). It is not clear what the actual reductions will be. In addition, those estimates were made before CAIR was promulgated; many of the reductions may now be accomplished under CAIR, although perhaps on a longer timetable than under the enforcement initiative. That, of course, assumes that CAIR takes effect despite the current litigation. It should also be noted that CAIR applies only in the eastern and midwestern region.

We discuss later the prospects of the enforcement initiative for further surrenders in allowances.

The History of the 2002 and 2003 Rule Changes

Shortly after his inauguration in 2001, President George W. Bush directed Vice President Richard Cheney to develop a national energy policy. A report that year from a task force chaired by the vice president recommended that legislation be introduced to cap NO_x and SO_2 emissions from electricity-generating facilities; this resulted in the Clear Skies legislation that the Bush administration has submitted to Congress. The report also recommended that EPA, in conjunction with the Department of Energy and other federal agencies, examine EPA's NSR regulations, including their administrative interpretation and implementation, and report on the effect of NSR on investment in new electricity generation and refinery generation, energy efficiency, and environmental protection.

EPA undertook a 90-day review of the NSR program and in June 2001 issued a background report (EPA 2001) that became the basis of a report to President Bush in May 2002 (EPA 2002b). Those reports concluded that the overall benefits of NSR are significant and that, so far as new sources are concerned, NSR has not substantially impeded the construction of new electricity-generating facilities or refineries. In contrast, the reports found that, when it comes to change in existing sources, NSR "has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity" (EPA 2002b). In some cases involving refineries and other industries, the reports found, the impeded projects either would not have increased air pollution or would have decreased air pollution. Those conclusions were based largely on anecdotal reports that lacked specifics about the projects (GAO 2003).

The report to the president recommended that changes be made in EPA's NSR regulations. EPA followed up on the recommendation by promulgating new rules in 2002.

The 2002 Rule Changes

The 2002 rules made the following alterations in EPA's NSR rules:

- Sources that are not electricity-generating facilities are allowed to calculate annual emissions before a proposed physical or operational change by averaging annual emissions in any 24-month period within the 10 years immediately before the change. The average must be reduced to reflect any tightening of the source's emission limit since that 24-month period. The previous rules had required such source to average its annual emissions over the 2 years immediately before the change unless the operator could show that a different period was more representative of normal operations. (Electricity-generating facilities continue to be allowed under the WEPCO rule to use any 2-year period within the 5 years immediately before the change.)

• A source that is not an electricity-generating facility is allowed to calculate annual emissions after a proposed physical change by projecting its actual emissions after the change. The projected emissions are compared with emissions before the change to see whether there would be a significant increase, so this method is known as the actual-to-projected-actual approach. The source need not obtain a permit that limits it to the projected emissions. (Electricity-generating facilities were already permitted by the WEPCO rule to use this approach.) Increases in emissions that result from increased demand, rather than from the change itself, can be excluded in calculating postchange annual emissions if the emission increase would have been physically possible during the 24-month period for calculating prechange emissions. If using the new method would exempt the project from NSR and it is reasonable to believe that the project might result in a significant emission increase, the source must track its postchange emissions for 5 years (10 years in some cases).[10] The previous rules, as described earlier, had used the source's postchange potential to emit (its maximum design emissions reduced in accordance with any legal limit on its emissions) as the measure of its postchange emissions; this method is now required only for new units at existing facilities.[11]

• Sources are allowed to seek permission to establish a plantwide applicability limitation (PAL)—a limit on emissions from the plant as a whole—to determine whether an individual physical or operational change increases emissions and therefore constitutes a modification. A PAL runs for 10 years and is renewable. Physical changes at a plant do not require an NSR permit so long as the PAL is not exceeded. The PAL's size for each pollutant is calculated by adding the appropriate "significance level" (see Box 2-1) to the source's average annual emissions (calculated under the 2-years-in-10 methodology described above for calculating prechange emissions). The previous rules had no similar provisions.[12]

• Physical changes at a "clean unit"—one that meets emission limits that are equal in stringency to those required under the NSR programs—were exempted from needing an NSR permit if the changed unit continues to meet its maximum-allowable emission rate. The unit need not have passed through NSR if its operator presents analyses of its air-quality effects that

[10]The D.C. Court of Appeals, in June 2005, remanded this requirement to EPA for explanation of why the agency does not apply it to all sources using the actual-to-projected-actual test (*New York v. EPA*, 413 F.3d 3 [D.C. Cir. 2005]).

[11]Many industries believe that NSR should apply only to a change that increases a source's potential to emit. EPA in 1982 promised to propose this approach in what is known as Exhibit B to the settlement in *Chemical Manufacturers Association v. EPA*. EPA proposed and rejected this approach in the 2002 rule making, and the New York court upheld the agency.

[12]This provision was modeled after a program that has been in effect in Oregon for a number of years.

are like those required by NSR. The exemption lasts for 10 years after pollution controls are brought into operation and is renewable if the pollution controls continue to be as strict as those required by NSR. This change was vacated in *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005) as beyond EPA's authority under the CAA.

- The existing exemption from NSR for PCPs was expanded. This exemption applies when a permitting authority deems the project to be environmentally beneficial, even if it would significantly increase emission of an air pollutant other than the pollutants reduced by the project. Sources no longer must show that reducing air pollution is the primary purpose of the PCP. In addition, the rule listed a number of projects presumed to be eligible for the exemption.[13] For more detail, see pages 20-22 of our interim report (NRC 2005). This change was vacated in *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005) as beyond EPA's authority under the CAA.

To support those revisions, EPA conducted an analysis for each of the changes being made and concluded that either varying levels of emission-reduction benefits or no significant effects would result from the 2002 changes. However, EPA indicated that it did not have sufficient data to quantify with specificity the emission changes that might result from the NSR rule changes. EPA also said it could not reliably determine the anticipated locations of any emission changes to estimate the rule's effects on public heath (EPA 2002c). GAO (2003) reviewed EPA's analysis and concluded that because the information used is anecdotal, EPA's findings do not necessarily represent the NSR program's effects across the industries subject to the program.

In response to petitions for reconsideration, EPA announced in the middle of 2003 that it would take further comments on its conclusion (EPA 2002c) that the new rules would benefit air quality (68 Fed. Reg. 44620 [2003]). Later that year, EPA decided to clarify some portions of the 2002 rule change but to otherwise leave them in place (68 Fed. Reg. 63021 [2003]). EPA justified that partly on the basis of a supplemental statement arguing that the rule changes were unlikely to affect the environment adversely.

Uncertainties About the 2002 Rules

There are a number of uncertainties about the meaning and impact of the 2002 changes:

[13]For nonlisted projects, the rule established detailed requirements that go well beyond previous policy on PCPs for demonstrating project eligibility.

- *The change in calculation of prechange emissions.* EPA has argued that, since a source must use today's emission limit to calculate its prechange emissions, the change in rules will have a practical effect only when the source was experiencing a drop in market demand or a forced outage in the 2 years prior to the change. In these situations, EPA contends, it is reasonable to assume that the source would have been able to persuade the permitting authority to use a more representative period than the 2 years prior to the source's permit application. It appears, however, that there was a substantial division among states in their willingness under the prerevision rules to allow a source to substitute a more representative period for the 2 years immediately preceding the change. There does not appear to be a relevant database on use of the "more representative" provision. Hence, it is difficult to appraise the impact of the change.
- *The actual-to-projected-actual test.* EPA suggests that the change would not increase emissions. Under the previous approach of comparing prechange actual emissions to postchange potential emissions, a source could avoid NSR by making a binding promise that it would never increase emissions by more than a significant amount over its prechange emissions. Allowing the source instead to compare its actual with its projected-actual emissions is, according to EPA, a simpler method of accomplishing the same result. Environmental groups dispute this, saying that the new methodology contains enforcement loopholes that could in practice allow an altered source to increase its emissions without being detected. For instance, environmental groups point out that a source must report its emissions only when there is a reasonable possibility of a significant increase, and argue that this test is vague enough to create a substantial gap in enforcement. Projecting the magnitude of these enforcement effects is very difficult.

Moreover, EPA suggests that the actual/potential test discouraged projects that, while theoretically increasing emissions under the test, would in reality lead to decreases in emissions. The validity of this position depends on the frequency of such projects and on the extent to which NSR applicability makes a difference to businesses in considering whether to undertake a project that would decrease emissions. This is difficult to determine. Similar difficulties are posed by EPA's decision that increases in emissions due to factors other than the physical or operational change (e.g., growth in demand for the source's product) need not be included in the projection. There is little information about whether excluding these emissions has a substantial impact on whether the increase in emissions would be great enough to be significant. EPA suggested in 1998 that a demand growth exclusion would be difficult to enforce, possibly inviting abuse (63 Fed. Reg. 39857 [1998]). Nor is it clear how easy it will be for sources to convince permitting authorities that an increase in emissions is due to factors other than the change.

- Establishment of PALs. The new rules authorize sources to obtain plantwide applicability limits—that is, caps on total emissions from the plant. A source with a PAL needs an NSR permit under the new rules only if the PAL is exceeded.

It is difficult to estimate how many sources are likely to adopt PALs. EPA suggests that use of PALs will be confined to sources that need to make rapid operational changes and for which it is therefore worthwhile to go through the process of establishing a PAL. In addition, it is unknown how sources with PALs would behave. EPA has been allowing the use of PALs in pilot projects. Based on that experience, EPA believes there is considerable potential for emission reductions. This occurs in part because a PAL can tighten the limit on a source's maximum allowable emissions. Without a PAL, a source's maximum allowable emissions are based on its potential to emit, taking into account legal limits on its emissions. A source operating under a PAL, however, is limited to actual emissions plus a margin for de minimis increases. Because sources typically operate below theoretical maximum capacity, a PAL considerably limits emissions from sources. Moreover, sources with PALs have an incentive to keep their emissions below PAL levels in order to avoid NSR. Environmental groups, on the other hand, point out that EPA is allowing actual emissions to be calculated by using the highest 24 months in the last 10 years, thus eliminating some of the reduction in maximum emissions.

Status of the 2002 Rules

In proposing a predecessor version of these rules in 1996, EPA stated that it would allow states to choose between following the old and the new rules. In contrast, EPA's 2002 rule requires that all states adopt these changes or changes that are at least as stringent. The agency considers its revised rules to be environmentally more beneficial than the prerevision rules; thus, states do not have the option of continuing to follow the prerevision rules (67 Fed. Reg. 80241 [2002]). Some state and local air-program officials strongly disagree with that position (STAPPA/ALAPCO 2002, 2003). EPA gave the states until January 2, 2006, to submit SIP revisions adopting the new or equivalently stringent measures. If a state does not submit an approvable revision, EPA may, after notice and public comment, insert its rules into the state's SIP. As of the writing of this report, EPA has taken no action to insert its rules into the SIPs of states that have not adopted the 2002 rules. The agency reports that it is evaluating its options for dealing with these states, including incorporating the 2002 changes directly into their plans or proposing sanctions for these states.

EPA indicated that, as of mid-April 2006, it has proposed approval of revisions by 5 states adopting the new rules, and that another 20 states have submitted revisions adopting the new rules or asking EPA to approve them as part of the SIP. According to the State and Territorial Air Pollution Program Administrators, 11 states have indicated that they will not adopt the new rules, and some states have not indicated their intentions.

In some areas, the PSD program is not part of the SIP. In those areas, changes went into effect on March 3, 2003. That occurred in about 50 jurisdictions (14 states and territories, 30 air-quality districts in California, such as those covering Los Angeles and San Francisco, and several localities such as Philadelphia, Pittsburgh, Phoenix, and Tucson) in which the PSD program is run by EPA directly or through a delegation agreement.

Fourteen states and several environmental groups filed suit in the D.C. Circuit Court of Appeals to overturn the 2002 rule. (Industry groups intervened to challenge the rule on several points.) In *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005), the industry challenge was rejected, as were several of the state and environmental challenges. For instance, the court upheld EPA's new approach of allowing sources, in general, to determine prechange annual emissions by averaging the highest 24-month period of emissions during the immediately previous 10 years. By contrast, the court vacated the "clean unit" and pollution-control-project portions of the rule as beyond EPA's authority under the CAA.[14] It also remanded to the agency for further explanation its decision not to require reporting by all sources using the actual-to-projected-actual methodology. It is not clear how or when the agency will respond.

2003 Rule Change: Routine Maintenance, Repair, and Replacement

On the same day that EPA promulgated the 2002 NSR revisions, EPA proposed changes in its definition of "routine maintenance, repair and replacement." This rule was promulgated in August 2003 and published in October 2003 (68 Fed. Reg. 61248 [2003]). The change—known as ERP—defines certain kinds of equipment replacements as "routine maintenance, repair, and replacement" and as therefore not constituting "physical changes or changes in the method of operation." Hence, these replacements do not need NSR permits, even if a significant emission increase can be expected to occur.[15]

Under the rule, the replacement of components of a process unit with

[14]The court's decision vacating the PCP exclusion also invalidates the PCP exemption previously made under the WEPCO rule discussed above.

[15]Sources often emit less than their maximum level of allowable emissions. Therefore, it is often possible for a source to increase emissions without exceeding its maximum allowable emissions.

identical components (or their functional equivalents) is exempt from NSR if

- The cost of replacing the component (including the fixed capital cost and costs of the replacement activity, such as construction) is less than 20% of the replacement value of the process unit.
- The replacement does not change the unit's basic design parameters.
- The unit continues to meet enforceable emission and operational limitations—that is, the unit, while possibly emitting more than in the past because of greater utilization, does not emit more than is legally allowed.

Under the previous rules, EPA used a case-by-case approach in determining which equipment replacements constituted routine maintenance, repair, or replacement. The ERP provided that the case-by-case approach continued to be available for a source whose project does not qualify under the categorical exemption.

EPA evaluated the possible emission consequences of the ERP through computer model analysis of the electricity-generating industry and six case studies of industrial sectors other than electricity generation. EPA concluded that the ERP would have little impact on future emission reductions. (Chapter 6 of this report discusses the use of industrial-sector modeling for assessing emission impacts of the ERP.)

On June 30, 2004, EPA announced a 180-day period for reconsideration of the rule. The agency requested comment on the rule's legality and on the choice of the 20% threshold (69 Fed. Reg. 40278 [2004]). The agency decided to adhere to the rule as promulgated (70 Fed. Reg. 33838 [2005]).

This rule never went into effect. In December 2004, the D.C. Circuit Court of Appeals issued a stay at the request of a coalition of some states and environmental groups on the grounds that the petitioners had shown irreparable harm and the likelihood of success on the merits. In March 2006, the D.C. Court of Appeals vacated the rule as beyond EPA's authority under the CAA (*New York v. EPA*, 443 F.3d 880 [D.C. Cir. 2006]).

Further Developments

EPA, as discussed in more detail below, proposed in 2005 adoption of an hourly emission test for determining whether a physical or operational change at an electricity-generating facility would increase emissions. This proposed change would compare the maximum achievable hourly emissions at a source before and after a physical or operational change. This is like the approach used in the NSPS program. Such a test would exclude from coverage those projects that, although not increasing the source's hourly emissions, raise annual emissions by increasing the number of hours the source can, in practice, operate each year. EPA has also invited comment on other approaches, such as comparing actual pre- and postchange hourly emissions. EPA expects to publish proposed regulatory language and an updated environmental assessment in the summer of 2006 and to take final action by the end of the year.

In September 2005, the House Committee on Energy and Commerce reported out H.R. 3853. As reported to the floor, the bill would have codified the ERP as well as the hourly-increase approach to whether an increase in emissions has occurred. These provisions were removed from the bill before it reached the floor of the House.

EPA also intends to propose in the summer of 2006 a rule dealing with debottlenecking and aggregation. Debottlenecking deals with the situation in which a change at an emission unit would make it possible for a source to increase production, and hence emissions, at units upstream or downstream of the changed unit. Questions have arisen about whether the upstream or downstream emission increases count in determining whether the source has increased emissions significantly. EPA, in promulgating its 2002 rule, promised action on the debottlenecking issue. The issue of aggregation involves deciding whether unrelated changes at a source should be combined in deciding whether there would be a significant increase in emissions. Both topics have long been issues in the NSR program.

Future Prospects for the Enforcement Initiative

As recounted earlier, the enforcement initiative led to a number of settlements in which electricity-generating facilities committed to cut emissions and surrender allowances. Whether this continues to occur depends on several factors. One important question is whether the courts will accept EPA's argument that the projects in question constitute "physical or operational changes" that "significantly increase emissions" and are therefore modifications that require PSD permits. Both quoted terms have been at issue.[16]

In EPA's enforcement initiative, the agency has argued that the definition of routine maintenance has three hallmarks:

> First, the exemption applies to a narrow range of activities, in keeping with EPA's limited authority to exempt activities from the [CAA.] Second, the exemption applies only to activities that are routine for a generating unit. The exemption does not turn on whether the activity is prevalent within the industry as a

[16]There is also the additional issue of whether the regulated companies had fair notice of the interpretation of routine maintenance that is the basis for the enforcement initiative. The one case on point, *U.S. v. Southern Indiana Gas & Elec. Co.*, 245 F. Supp. 2d 994 (S.D. Ind. 2003) has held that there was such notice.

whole. Third, no activity is categorically exempt. EPA examines each activity on a case-by-case basis, looking at the nature and extent, purpose, frequency, and cost of activity (*U.S. v. Southern Indiana Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1008 [S.D. Ind. 2003]).

The courts have thus far split on whether to follow this interpretation. Two published district court decisions (*U.S. v. Southern Indiana Gas & Elec. Co.*, 245 F. Supp. 2d 994 [S.D. Ind. 2003] and *U.S. v. Ohio Edison Co.*, 276 F. Supp. 2d 819 [S.D. Ohio 2003]) have upheld EPA's multifactor reading as reasonable. Two other decisions disagree and have consequently dismissed enforcement actions (*U.S. v. Duke Energy Corp.*, 278 F. Supp. 2d 619 [M.D. N.C. 2003] *aff'd on other grounds*, 411 F.3d 539 [4th Cir. 2005], *cert. granted sub. nom.*; *Environmental Defense v. Duke Energy Corp.*, No. 05-848 [May 15, 2006]; and *U.S. v. Alabama Power Co.*, 372 F. Supp. 2d 1283 [N.D. Ala. 2005]). The latter decisions hold that the key question is whether similar plants undergo the same project.[17] Thus, under the enforcement initiative's view, a project that is likely to occur only once in a plant's life would generally not qualify as routine maintenance; the disagreeing courts hold that such a project can be routine maintenance if it is routine in the industry to carry it out. The Ohio Edison and Duke Energy decisions also split on which party has the burden of showing that a particular project constitutes routine maintenance; the former holds that the burden is on the source to show that the project is routine maintenance, and the latter concludes that the burden is on the government to show that it is not.

The recent decision in *New York v. EPA* invalidating the ERP provision may affect future judicial interpretations. There the D.C. Circuit held that EPA may exempt physical or operational changes only if an exemption has a de minimis effect on the environment or is administratively necessary. Arguably, under such a test, the scope of the routine-maintenance exemption is restricted. But because the decision is so recent, it is difficult to predict its consequences.

The cases also disagree on how to define whether an increase in emissions has occurred. A project at an existing source may be intended to allow the source to run more often (and thus emit more over the course of a year), rather than to increase its emissions during any given hour of operation. There is debate about whether such a project has increased emissions within the CAA's meaning and thus requires an NSR permit. EPA has argued in the enforcement initiative litigation that NSR covers a source that significantly increases annual emissions even if there is no increase in

[17]The recent decision in *U.S. v. Cinergy Corp.* (S.D. Ind. slip opinion, Feb. 16, 2006) seems to adopt an intermediate view. It agrees with EPA's view of the scope of the routine-maintenance exemption but allows industry practice to be considered as a factor in judging whether a particular project constitutes routine maintenance.

hourly emissions. This interpretation, which the agency has long followed, contrasts with the NSPS program, in which a project is covered only if it would increase maximum hourly emissions. *Ohio Edison* and the recent district court decision in *U.S. v. Cinergy Corp.*, 384 F. Supp 2d 1272 (S.D. Ind. 2005) (permission to appeal granted by the 7th Circuit Court of Appeals, Jan. 3, 2006), agree with the agency's view, while Duke Energy holds that an increase in the hourly emission rate also must have occurred. The latter holding was affirmed in *U.S. v. Duke Energy Corp.*, 411 F.3d 539 (4th Cir. 2005). The recent *New York v. EPA* decision by the D.C. Circuit on the 2002 EPA rules, however, disagrees with this approach. The U.S. Supreme Court recently decided to hear an appeal by environmental groups of the Duke Energy decision (*Environmental Defense v. Duke Energy Corp.*, No. 05-848 [May 15, 2006]).

Given the disputes over the scope of NSR, it is difficult to estimate what emission reductions would be brought about by EPA's enforcement theory. There is an additional reason for this. EPA proposed in October 2005 to adopt the *U.S. v. Duke Energy* approach for electricity-generating facilities (70 FR 61081 [2005]). Existing electricity-generating facilities would, as in the NSPS program, compare the maximum hourly emissions achievable at that unit during the past 5 years to the maximum hourly emissions achievable at that unit after the change to determine whether an emissions increase would occur. The agency said that the proposed change was needed to assure uniformity between the nation as a whole and the states within the 4th Circuit. EPA argued in addition that the proposed approach would allow electricity-generating facilities to make changes that promote their safety, reliability, and efficiency and that the change was desirable in view of the substantial emissions reductions from programs more efficient than NSR. These latter rationales resemble those put forth for the 2003 rule establishing the now-invalidated ERP, although the legal theory behind the proposed hourly emission rule is different from that underlying that rule.

EPA's proposal of this rule may cause difficulty in applying the enforcement initiative to past projects that violated the theory underlying the initiative. Legally speaking, the proposal or adoption of a new rule is not retroactive, and therefore, enforcement actions based on the previous rules may proceed. But, as a practical matter, a court might be reluctant to find liability or to impose a substantial penalty for violating rules that are no longer in force. (This concern was voiced by EPA enforcement officials when the ERP was adopted in 2003 [EPA 2004c] and more recently when the hourly emission test was proposed [Eilperin 2005]). Indeed, the *U.S. v. Alabama Power* case, summarized above, used the promulgation of the ERP as an argument against EPA's enforcement theory. Hence, the proposed rule changes could diminish the size of future settlements. Estimating the magnitude of this effect is difficult.

The potential of the enforcement initiative to reduce emissions also depends on the number of lawsuits brought under the initiative and the aggressiveness with which they are prosecuted. According to press reports, 22 electricity-generating facilities could face new NSR enforcement lawsuits if the Bush administration decided to advance them (Samuelsohn 2004). None, however, have been brought. In October 2005, EPA administrator Stephen Johnson announced that no new enforcement actions would be pursued under the enforcement initiative's theory (Greenwire 2005). If EPA holds to this position, the only future enforcement actions will be those brought by states or individuals under the CAA's citizen suit provision. It is uncertain how many such suits there will be; the lengthy trials that have occurred so far in enforcement cases indicate that these cases are quite resource-intensive.

This is especially important because only enforcement actions against violators result in the surrender of allowances. By contrast, a source that complies with EPA's NSR rules need not surrender allowances. Instead, compliance would reduce an electricity-generating facility's need to find additional allowances to accommodate the emission increase at the facility that would be caused by the change. These allowances would then be available to other sources, perhaps resulting in increases in emissions from those sources that might offset, in part or in whole, the effect of compliance by the source seeking an NSR permit. This has special significance because there will likely be fewer enforcement actions once the definition of routine maintenance becomes more certain as cases are decided; it is reasonable to expect that operators of electricity-generating facilities will adjust their conduct to meet the requirements of that definition. It is therefore quite difficult to estimate the changes in emissions—whether local or national—that would be brought about by the enforcement initiative and therefore to gauge the effects of alterations in the NSR program.

The situation is further complicated by the establishment of CAIR subsequent to the adoption of the 2002 and 2003 rule changes. As discussed above, CAIR tightens the Title IV cap for SO_2 and requires reductions in NO_x emissions in the East and Midwest. To be useful, any analysis of changes in the NSR rules must take into account the potential implementation of CAIR. This makes the analysis more complex. We address this later in our report. Because CAIR covers only the East and Midwest, it has little or no effect on emissions outside that region and will have little impact on emissions from plants that are not electricity-generating facilities. Moreover, the CAIR program does not cover emissions of carbon monoxide (CO), PM, and VOCs. Hence, the program does not compensate for whatever changes in emissions of these pollutants that might be caused by EPA's position on the coverage of NSR. For instance, the changes in Part D NSR coverage may reduce the number of projects in the northeastern Ozone Transport

Corridor that are subject to NSR. Any resulting emission increases are not guaranteed to be offset by other programs such as CAIR. On the other hand, the CAIR program, by encouraging reductions in SO_2 and NO_x emissions, might lead to the retrofitting of controls that would also reduce CO, PM, and VOC emissions.

CLOSING COMMENTS

The regulatory background has continued to evolve during the period of our study. New settlements have been reached, new regulatory initiatives have been unveiled, and court decisions that affect the NSR programs have been handed down. We have tried to take into account all those changes in our report. However, we caution the reader that matters have not yet come to rest and that NSR will probably be affected by future and unpredictable events.

Three matters are particularly significant:

- The 2002 rules are partly in effect in a few states; the remaining portions were struck down. The 2003 rules never went into effect and have been invalidated.
- It is unclear at this writing how much emission reduction will be brought about by the enforcement initiative. That is partly because the courts have split over whether the enforcement initiative is in accord with the CAA. This makes it difficult to analyze the effects of changes to the NSR programs.
- As we have stressed, the CAIR rule (whose fate in the courts is undetermined) may have a substantial effect on the consequences of the NSR reforms.

3

Emission Sources Subject to New Source Review and Technology Options

INTRODUCTION

The purpose of this chapter is to address the following key questions:

- What source categories account for a substantial portion of permitting activity pertaining to modifications under New Source Review (NSR)?
- Are modifications an important part of all NSR permitting?
- What is the current status of state permitting programs and availability of permit data?
- What is the correct status of state permitting programs and availability of permit data?
- What are the most common kinds of repairs and replacements in selected industries?
- What are the typical technology options or considerations regarding those source categories?

The answers to those questions provide insight into the emissions, energy use, and other implications of technological choices regarding preventive measures, repairs, and replacements. In this chapter, we use language that implies the colloquial meanings, as opposed to the "legal" terminology of *maintenance* and *modification* as these terms are used in NSR permitting. It is common in many industries to refer to repair and replacement activities as maintenance (in a nonlegal sense) and for maintenance costs to be considered a routine part of the annual operating cost of a facility. To avoid confusion with legal terminology, in this chapter we use the terms *repair* and *replacement* instead of *maintenance* and *modification*.

The main focus here in terms of pollutants is on selected criteria pollutants, especially sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) but also including carbon monoxide (CO), particulate matter (PM) with an aerodynamic diameter smaller than about 10 μm (PM_{10}), and PM with an aerodynamic diameter smaller than about 2.5 μm ($PM_{2.5}$). Volatile organic compounds (VOCs), which are ozone precursors, are also included.

With respect to identifying technology options, the focus here is on the current status of emission-source technologies and current options for repair and replacement. However, because technology changes, explicit consideration is given to the process of technology change and the implications for technology change in the future. Furthermore, we consider both pollution control and pollution prevention. Typically, pollution control refers to "end-of-pipe" techniques for removing pollutants from an exhaust gas after they have been formed in an upstream process. For example, in a coal-fired power plant, NO_x, SO_2, and PM are formed during combustion. Postcombustion control technologies—such as selective catalytic reduction, flue-gas desulfurization, and electrostatic precipitation, respectively—can be used to reduce or capture those pollutants. In contrast, pollution prevention is aimed at reducing or eliminating sources of pollution, typically through feedstock substitutions or process alterations. For example, in the case of a coal-fired power plant, methods that control and stage mixing of fuel and air more carefully can prevent the formation of a portion of NO_x that otherwise would have been created, and evaporative VOC emissions can be prevented by substituting water-based solvents for VOC-based solvents in a manufacturing facility. In addition, cost is always a consideration in evaluating and choosing options for repair and replacement. Therefore, cost implications of alternatives for repair and replacement are summarized.

OVERVIEW OF NEW SOURCE REVIEW PERMITS

The purpose of this section is to identify and evaluate the frequency of NSR permitting activity with respect to industrial categories for the purpose of determining which emission sources represent the highest priority for assessment. However, a substantial challenge is that there is not a readily available database that summarizes NSR permitting activity. For example, an Environmental Protection Agency (EPA) database[1] (EPA 2004d) containing case-specific information on best available control technology (BACT) and lowest achievable emission rate (LAER) does not readily distinguish

[1]The database is referred to as the RACT-BACT-LAER clearinghouse. RACT means reasonably available control technology.

between permits for new sources and permits for modifications. In principle, such data could be obtained individually from each state, but the availability of such data varies among states.

An overview of permitting activity was gleaned from information provided by EPA during preparation of the committee's interim report (NRC 2005), supplemented with information obtained in the intervening period. We provide here a summary based on the interim report followed by a summary of the additional information.

In its interim report, the committee obtained data provided by EPA as the basis of a summary of permitting activity. That information is included in Appendix D. The data provided by EPA are unpublished, were not subjected to review, and have not been distributed outside EPA. The data were based on information collected internally by EPA from its regional offices that were obtained from state and local permitting authorities. They were summarized by EPA for the committee in terms of the NSR permitted emissions (in tons) by two-digit Standard Industrial Classification (SIC) code and by number of permits. Permits were categorized as "greenfield,"[2] new at existing sources, and modifications. The main focus here is on modifications. The data do not include information on facilities that made modifications but did not obtain permits via the NSR program. Although the information presented in the table is sorted by pollutant, it is possible for a modification to involve more than one pollutant.

For NO_x, the largest share of modification permits—in both number of permits (46%) and NSR permitted emissions (35%)—was for SIC type 49 (electric, gas, and sanitary services).[3] SIC type 49 includes electricity-generating plants of all types, and most of the permits and permitted emissions were for SIC code 4911, electric services. SIC types 32 (stone, clay, and glass products) and 26 (paper and allied products) also had a large share of the reported NSR permitted emissions for modifications (27% and 10%, respectively) but substantially fewer than for SIC type 49. For SIC type 32, the most important source category was SIC code 3241, hydraulic cement. Pulp mills (SIC code 2611) were the most commonly permitted source for modifications under SIC type 26. NO_x emission sources at these types of facilities are typically industrial or electricity-generating-plant furnaces but can include a variety of other combustion-based sources, such as heaters, kilns, and ovens.

For SO_2, the key emission-source category in number of modification

[2]A greenfield emission source refers to a source that is part of a newly constructed facility at a site where no facility had previously existed.

[3]This group includes establishments primarily engaged in the generation, transmission, and/or distribution of electricity or gas or steam. It also includes irrigation systems and sanitary systems involved in the collection and disposal of garbage, sewage, and other wastes.

permits (31%) and NSR permitted emissions for modifications (27%) was SIC type 49 (electric, gas, and sanitary services), for which SIC code 4911 (electric services) was the most important subcategory. Other source categories with large totals for NSR-permitted emissions for modifications included SIC types 28 (chemicals and allied products, particularly industrial inorganic chemicals and phosphatic fertilizers) (24%), 32 (stone, clay, and products, particularly hydraulic cement) (22%), and 26 (paper and allied products, particularly pulp, paper, and paperboard mills) (14%). SO_2 emissions typically are associated either with combustion of sulfur-bearing fuels or with processing of sulfur-bearing feedstocks or ores (such as crude oil and metal ores).

For CO, the largest number of permits for modifications was issued to SIC types 49 (which includes electric, gas, and sanitary services) and 33 (which includes primary metal industries). With respect to NSR permitted emissions for modifications, the largest categories (in descending order) were SIC types 26 (paper and allied products, primarily paperboard mills), 32 (stone, clay, and glass products, primarily hydraulic cement and concrete block and brick), 33 (primary metal industries), 20 (food and kindred products, primarily cane sugar), and 49 (electric, gas, and sanitary services, primarily electricity-generating facilities).

For PM, the highest frequency of NSR permits for modifications was for SIC types 49 (electric, gas, and sanitary services) and 33 (primary metal industries). Although both those types also contributed to the NSR permitted emissions for modifications, these emissions are widely distributed among six categories, including SIC types 28 (chemical and allied products, primarily carbon black, phosphatic fertilizers, and industrial organic chemicals), 26 (paper and allied products, primarily paperboard mills, pulp mills, and coated and laminated paper), and 20 (food and kindred products, primarily cane sugar).

For VOCs, the highest frequency of permits for modifications was for SIC types 49 (electric, gas, and sanitary services), 33 (primary metal industries), and 24 (lumber and wood products). The largest share of NSR permitted emissions for modifications was for SIC types 26 (paper and allied products, with a large contribution from coated and laminated paper), 20 (food and kindred products, with a large contribution from soybean oil mills), and 24 (lumber and wood products).

The summary above is subject to several key limitations. Complete permit data were not available for every permit issued. The survey was for a specific period (1997-1999); more-recent data were not available. Some sources accept limits on their emissions by state permits when modifications are made and so are not included in the EPA database. There is some uncertainty in estimated NSR permitted emissions because emission rates are often reported on a short-term basis and had to be converted to an estimate of annual emissions. Actual emissions are typically less than what is allowable. During the survey period, there was a noticeable increase in the number of new natural-gas-fired turbines permitted, which would affect totals for greenfield sites and new facilities at existing locations. However, that probably does not substantially affect the frequency of permits issued for modifications. The data do not include situations in which NSR permits for major modifications were not issued, such as for facilities that considered but decided against making a modification or facilities that made modifications but did not get an NSR permit for a major modification, whether because of noncompliance or because the source agreed to reduce emissions and obtained a state permit. Despite the limitations of the data, they are among the most comprehensive available.

The summary of permitting activity from the interim report is updated here on the basis of data from EPA that include the period 1997-2002. These data are similar to those provided in summary form by EPA for the interim report, with the same caveats and limitations except that the update includes additional years (2000-2002) and the committee had access to the underlying data and so could generate its own summary tables. The information presented also includes Census data on the number of facilities in each state and EPA data on the number of emitting facilities and their total emission amounts. The information is summarized here with respect to the following two objectives: (1) determine the overall permitting activity when comparing electricity-generating and other sectors, and (2) for the SIC codes of sectors other than electricity generating that have the most permitting activity, identify the states with the largest share of this activity occurring. Table 3-1 compares NSR permitting activity by pollutant, selected states, and manufacturing vs electricity-generating sectors; and Table 3-2 compares permitting activity by pollutant, selected states, and selected manufacturing industries.

Although the general conclusions are the same, the updated summary enables more specific insights regarding permitting activity on a state level and regarding the relative importance of electricity generation versus manufacturing sectors.

On the basis of Table 3-1, in general, the emissions associated with permits for modifications are about 1.5-2.3% of the total emissions for a given pollutant for the manufacturing sector (including facilities not granted a permit in that period). For the electricity-generating sector, the emissions associated with permits for modifications are 0.1-1.1% of total emissions except for CO, for which they are 3.6% of total emissions. Overall, therefore, the amount of emissions associated with permits for modifications are about 1-2% of total emissions for most pollutants and types of industrial facilities.

In general, 33.1-41.2% of all NSR permits issued in the manufactur-

TABLE 3-1 NSR Permit Activity Pollutant, 1997-2002, Manufacturing versus Electricity Generation[a]

Manufacturing Sector										
Number of Permits					Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	tpy
Carbon monoxide										
AL	24	2	12	7	385	6,729	5,353	5,444	386	190,106
WI	13	2	6	5	240	1,831	2,875	9,936	907	56,427
AR	12	1	5	6	3,694	3,054	12,206	3,316	96	93,876
LA	11	0	7	5	-	8,360	3,315	3,545	198	592,306
NC	10	0	4	5	-	14,067	4,470	11,306	886	63,506
FL	9	1	4	2	490	2,894	15,697	15,992	234	48,569
IL	8	0	4	4	-	5,701	515	17,953	1,644	114,147
TX	6	0	4	2	-	1,059	6,422	21,808	466	386,465
OH	5	0	2	5	-	7	5,589	17,974	342	701,527
TN	5	0	2	2	-	2,271	338	7,407	211	91,929
IN	5	1	3	1	135	1,180	272	9,303	341	237,363
Total	148	10	71	59	5,813	72,785	73,750	363,753	12,949	4,351,945
Nitrogen oxides										
AL	25	3	13	6	287	5,206	2,258	5,444	382	66,693
LA	18	1	11	5	186	3,442	2,504	3,545	214	146,447
FL	16	1	7	5	394	3,428	622	15,992	270	44,255
AR	10	1	3	4	406	86,700	2,936	3,316	102	31,170
IL	10	0	5	4	-	5,875	1,486	17,953	2041	102,435
WI	10	2	6	2	1,842	916	360	9,936	951	43,953
NC	8	1	3	3	767	1,127	4,175	11,306	912	43,718
TX	6	0	4	2	-	2,093	8,329	21,808	470	280,741
PA	6	0	2	1	-	4,889	916	17,128	476	110,514
TN	6	0	3	3	-	4,013	487	7,407	232	60,711
IN	6	1	3	2	75	1,022	2,102	9,303	358	43,912
OH	6	0	3	5	-	138	1,637	17,974	345	69,263
MN	6	0	3	1	-	1,194	106	8,091	278	20,808
CA	5	0	0	2	-	-	1,577	49,418	1,804	73,855
Total	181	13	85	60	6,463	133,659	36,343	363,753	14,515	1,803,675
Particulate matter (PM_{10})										
AL	27	2	12	11	86	913	1,605	5,444	535	35,287
FL	26	2	12	10	24	1,401	2,561	15,992	351	13,846
WI	19	2	11	8	126	466	243	9,936	812	9,748
LA	18	1	9	7	14	1,223	447	3,545	202	30,334
NC	12	1	4	4	177	474	877	11,306	1,222	19,405
IL	9	0	4	4	-	736	132	17,953	2,615	45,727
AR	8	1	4	3	247	568	477	3,316	101	13,485
KY	8	0	4	2	-	172	734	4,218	511	10,773
OH	7	0	4	5	-	30	3,375	17,974	516	34,887
TN	7	0	3	3	-	658	169	7,407	164	2

Electricity-Generating Sector							
Number of Permits				Permitted Emissions (tpy)			Emissions (tpy)
Tot	Grn	New	Mod	Grn	New	Mod	
31	10	12	1	7,970	14,664	4,545	12,005
18	0	9	3	-	3,729	444	7,856
16	6	3	0	5,687	1,705	-	12,413
19	4	3	3	3,151	674	1,780	35,071
13	5	2	2	2,285	625	235	13,848
61	29	11	8	8,119	2,636	5,563	23,297
36	4	3	0	5,688	9,153	-	16,536
62	5	2	0	3,850	887	-	101,286
12	0	3	0	-	2,563	-	15,868
3	1	2	0	1,284	433	-	10,935
17	8	1	0	5,444	221	-	16,930
557	166	104	39	119,977	63,637	24,090	677,206
33	15	11	1	5,349	5,236	892	235,480
18	4	1	3	1,962	559	929	178,812
66	29	12	13	22,507	3,214	20,826	310,279
16	6	3	0	4,431	1,418	-	65,935
37	4	2	0	1,666	4,379	-	330,587
19	0	13	4	-	5,231	886	120,543
13	5	2	0	5,389	2,040	-	274,309
62	5	2	0	4,149	346	-	502,201
27	3	3	0	650	142	-	275,072
3	1	2	0	2,032	643	-	311,678
17	9	1	0	4,287	132	-	402,124
13	0	3	0	-	3,462	-	557,700
4	1	2	0	782	737	-	127,232
14	8	0	1	1,498	-	247	34,541
572	180	108	46	120,370	45,036	31,234	7,193,141
28	14	11	1	2,407	2,237	259	9,080
55	30	9	7	2,706	672	1,125	11,419
14	0	8	2	-	1,250	164	5,968
10	5	4	2	1,230	252	352	3,850
11	6	4	2	882	281	87	14,357
10	6	3	0	1,700	1,389	-	12,090
8	5	3	0	1,966	676	-	1,930
8	4	2	0	2,017	511	-	19,393
3	0	3	0	-	458	-	16,562
1	1	1	0	214	54	-	33,764

continues

TABLE 3-1 Continued

Manufacturing Sector										
Number of Permits					Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	tpy
Particulate matter (PM_{10}) *continued*										
VA	7	0	3	4	-	161	90	5,986	854	13,514
IN	6	0	4	2	-	472	253	9,303	456	14,689
MS	6	2	1	3	111	13	116	3,008	103	7,712
TX	5	0	3	2	-	219	1,497	21,808	419	34,010
IA	5	0	1	3	-	197	628	3,749	32	7,379
SC	5	3	3	0	282	86	-	4,450	172	8,137
GA	5	0	2	2	-	55	236	9,083	145	29,335
CA	5	0	0	2	-	-	222	49,418	1,520	15,891
Total	207	14	99	80	1,067	11,656	13,936	363,753	15,397	606,681
Sulfur dioxide										
FL	20	1	7	11	37	3,161	21,247	15,992	237	7,3497
AL	14	0	7	6	-	2,137	3,319	5,444	327	84,797
IL	8	0	3	4	-	16,392	2,747	17,953	1,130	240,356
WI	8	2	4	2	82	685	104	9,936	637	80,598
LA	7	0	5	2	-	10,763	1,995	3,545	132	151,246
NC	7	1	2	3	244	5,661	5,837	11,306	755	72,180
AR	7	1	2	3	791	232	10,401	3,316	86	54,095
OH	6	0	2	5	-	1,590	2,719	17,974	334	330,991
IN	6	1	3	2	39	384	2,400	9,303	330	125,434
TX	5	0	3	2	-	93	12,600	21,808	369	233,257
IA	5	0	1	3	-	5,913	2,132	3,749	30	67,285
TN	5	0	2	3	-	902	585	7,407	107	122,658
VA	5	0	2	2	-	612	117	5,986	664	97,063
Total	131	8	58	54	1,206	53,725	68,349	363,753	9,776	2,914,441
Volatile organic compounds										
WI	36	2	23	10	93	2,934	743	9,936	1,233	56,490
AL	27	3	8	10	2,023	1,308	1,843	5,444	566	88,546
LA	13	1	8	5	12	2,702	3,188	3,545	235	90,490
AR	12	0	7	3	-	1,696	837	3,316	117	33,988
FL	12	1	5	3	16	420	1,990	15,992	507	18,622
NC	11	0	7	3	-	2,372	1,148	11,306	1,156	78,718
GA	11	0	3	5	-	448	1,316	9,083	227	32,111
IL	10	0	4	7	-	6,645	2,443	17,953	1,741	136,081
SC	10	3	5	0	844	1,504	-	4,450	187	46,631
KY	9	1	2	4	107	609	4,116	4,218	559	57,951
MI	8	0	5	2	-	2,935	103	1,6045	765	71,594
MS	8	1	4	3	678	501	1,148	3,008	188	39,079
OH	8	0	2	5	-	3	2,251	17,974	820	77,781
TX	8	0	5	3	-	405	1,451	21,808	568	192,080
VA	8	0	3	4	-	991	301	5,986	822	55,460

Electricity-Generating Sector								
Number of Permits				Permitted Emissions (tpy)				Emissions (tpy)
Tot	Grn	New	Mod	Grn	New	Mod		
17	8	5	1	1,547	417	115		4,825
8	7	1	0	1,436	22	-		13,307
11	8	3	0	1,497	848	-		1,964
5	3	2	0	702	139	-		23,372
3	1	2	0	213	93	-		3,020
2	2	0	0	266	-	-		7,208
10	8	2	1	1,296	353	438		8,519
4	3	1	0	452	38	-		3,283
303	156	85	34	30,119	11,358	3,822		35,1410
53	27	11	7	5,991	616	20457		698,288
15	8	5	1	945	9,365	324		568,542
7	4	2	0	383	5,632	-		833,311
14	0	9	2	-	1,588	148		238,313
3	1	1	1	215	3	21		131,565
9	4	3	0	1,125	576	-		478,640
7	3	2	0	198	137	-		85,554
3	0	2	0	-	10,503	-		1,491,039
7	7	0	0	771	-	-		986,065
5	3	2	0	312	122	-		684,100
1	0	1	0	-	0	-		173,424
2	1	1	0	428	95	-		546,745
14	7	5	1	657	357	14		215,026
244	126	68	22	43,919	37,075	25,334		13,421,975
16	0	10	3	-	344	185		942
22	11	7	1	1,983	853	598		2,991
7	3	3	1	94	97	97		14,964
8	5	3	0	733	857	-		1,390
51	27	8	5	1,224	211	313		4,279
11	5	3	2	177	73	23		3,504
9	4	3	0	303	114	-		1,236
7	4	3	0	792	252	-		6,198
2	2	0	0	607	-	-		524
5	4	1	0	1,245	24	-		1,541
15	6	7	3	873	454	65		3,819
10	7	3	0	731	797	-		3,355
2	0	1	0	-	39	-		2,089
6	3	2	0	441	55	-		22,749
15	8	5	1	956	98	83		1,519

continues

TABLE 3-1 Continued

Manufacturing Sector										
Number of Permits					Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	tpy
Volatile organic compounds ***continued***										
IN	7	0	5	2	-	696	382	9,303	658	41,206
MN	7	0	4	1	-	622	53	8,091	295	34,344
TN	7	0	2	3	-	126	479	7,407	392	108,326
IA	5	0	2	2	-	310	929	3,749	32	10,901
Total	230	12	112	77	3,773	30,483	25,255	363,753	19,625	1,714,148

[a]NSR permit data are unofficial from EPA—preliminary, unpublished, not subjected to review, or not distributed outside EPA; this may not be a complete list of all NSR permits obtained in 1997-2002.

NOTE: Table lists only states with five or more NSR permits in manufacturing plants, but totals are for all states.

ing sector and 9.0-25.6% in the electricity-generating sector were issued for modifications, depending on the pollutant. Thus, in both sectors, the number of permits issued for modifications is less than the number issued for either new facilities at existing locations or new and greenfield facilities combined.

Typically, only a few states contribute substantially to the national total emissions associated with permits for modifications for a given pollutant and sector. For example, for NO_x, five states (Florida, Arkansas, Texas, Ohio, and Alabama) contribute 61.4% of the total emissions associated with such permits in the manufacturing sector, whereas a different set of five states (Alabama, Illinois, Wisconsin, Florida, and Ohio) contribute 47.8% of the total permitted emissions associated with modifications in the electricity-generating sector. For SO_2, only three states (Florida, Texas, and Arkansas) contribute 64.7% to emissions associated with modification permits in the manufacturing sector, and Florida alone contributes 80.7% to the total emissions for modification permits in the electricity-generating sector. In general, in the manufacturing sector, the top five states shown in Table 3-1 contribute 55.4-78.1% of the national emissions associated with permits for modifications. Similarly, the top five states contribute 47.8-82.8% of the emissions associated with modification permits in the electricity-generating sector. Therefore, in general, a substantial portion of the total emissions associated with permits for modifications can be attributed to a relatively small number of states.

Electricity-Generating Sector								
Number of Permits				Permitted Emissions (tpy)				Emissions
Tot	Grn	New	Mod	Grn	New	Mod		(tpy)
7	7	0	0	573	-	-		2,712
4	1	1	0	42	20	-		2,788
2	1	1	0	99	58	-		7,393
1	1	0	0	59	-	-		613
279	133	79	29	17,087	5,187	1,667		160,666

ABBREVIATIONS: Census plants = number of establishments in manufacturing industries in state, taken from 1997 Economic Census; emissions = 1997 EPA point-source emission data (unpublished, not 1996 National Emissions Inventory [NEI] data), includes number of plants with any emissions of this pollutant and total emissions; Grn = Greenfield; Mod = modification; New = new unit at existing plant; Tot = total; tpy = tons per year.

Alabama, Arkansas, Florida, Ohio, North Carolina, and Texas have substantial permitting activity in the manufacturing sector for modifications for three or more of the five pollutants listed in Table 3-1. Alabama, Florida, Louisiana, and Wisconsin have substantial permitting activity for modifications in the electricity-generating sector for three or more pollutants.

Table 3-2 provides examples of the distribution of NSR permits among selected industries and states for five pollutants in the manufacturing sector. For example, for NO_x, the paper and allied products industry contributed about 21.7% to the emissions associated with permits for modifications, and the largest share of the activity for this industry was in North Carolina. For SO_2, the chemical and allied products industry and the paper and allied products industry combined for 57.5% of the total emissions associated with permits for modifications in the manufacturing sector. Most of that activity was in Florida, Arkansas, and North Carolina. For PM_{10}, the two industries combined account for about half the total emissions associated with permits for modifications in the manufacturing sectors, with only a handful of states (e.g., Alabama, North Carolina, Kentucky, and Florida) contributing substantial shares. The primary metal industries and the paper and chemical industries had substantial permitting activity for CO, including permits for modifications totaling 1,000 tons/year or more in six states. VOC emissions tend to be dispersed among many industries. The paper and allied products industry contributed 28.3% of the total emissions associated with permits for modifications; a large share of the industry total was in

TABLE 3-2 NSR Permit Activity by Pollutant, 1997-2002, Selected Manufacturing Industries[a]

	Number of Permits				Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	Emissions
Carbon monoxide										
					SIC 26: Paper and Allied Products					
AL	5	1	2	2	215	2,811	1,555	19	21	5,3208
AR	3	0	1	2	-	917	3,920	8	7	3,2977
NC	3	0	1	2	-	8,678	3,920	14	29	1,7926
WI	3	0	3	0	-	1,305	-	51	89	24,496
GA	2	0	2	1	-	707	185	25	21	142,217
Total	20	1	12	8	215	25,626	9,148	543	722	552,075
					SIC 28: Chemicals and Allied Products					
LA	5	0	4	1	-	464	263	16	90	448,938
AL	3	0	2	1	-	239	578	12	27	46465
KY	2	0	1	0	-	473	-	11	45	1,125
MI	2	0	1	1	-	865	863	48	47	1,289
TX	2	0	2	0	-	334	-	94	184	265,755
Total	20	0	13	7	0	2,761	7,719	1,733	1,518	1,255,846
					SIC 20: Petroleum and Coal Products					
LA	3	0	1	2	-	297	1,828	54	25	78,071
IL	2	0	0	2	-	-	38	93	152	2,945
TX	2	0	2	0	-	725	-	194	38	41,077
Total	9	0	4	4	0	1,070	1,866	2,074	1,500	460,508
					SIC 33: Primary Metal Industries					
WI	8	0	3	5	-	526	2875	6	77	14,067
AL	3	0	2	1	-	2,239	37	11	45	38,900
AR	3	1	1	1	3,694	753	3,942	7	10	6,055
IN	2	0	1	1	-	585	272	18	54	193,361
NC	2	0	1	1	-	4,380	436	1	20	6,568
OH	2	0	1	2	-	5	4,201	29	52	572,213
OR	2	0	0	2	-	-	2,521	5	15	5,947
TN	2	0	0	1	-	-	192	9	14	12,386
VA	2	0	1	1	-	3,473	341	4	21	2,340
Total	35	2	13	19	3,880	15,843	16,820	287	893	1,658,200
					SIC 37: Transportation Equipment					
AL	3	1	2	0	171	482	-	6	8	409
Total	3	1	2	0	171	482	0	355	593	1,7434
Nitrogen oxides										
					SIC 26: Paper and Allied Products					
AL	5	1	2	2	129	1,715	1,723	19	19	31,516
WI	3	0	3	0	-	324	-	51	90	28,858

TABLE 3-2 Continued

	Number of Permits				Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	Emissions
Nitrogen oxides *continued*										
					SIC 26: Paper and Allied Products (continued)					
AR	2	0	1	1	-	86,264	711	8	7	18,523
GA	2	0	2	1	-	386	125	25	21	34,011
NC	2	0	0	2	-	-	4,071	14	30	13,897
Total	21	1	11	9	129	92,724	7,903	543	786	318,804
					SIC 28: Chemicals and Allied Products					
LA	8	1	6	0	186	1,813	-	16	93	73,815
FL	7	0	3	3	-	226	180	69	36	8,974
AL	5	0	3	1	-	405	251	12	35	8,022
AR	2	0	0	1	-	-	1,091	8	14	4,688
KY	2	0	1	0	-	229	-	11	48	5,564
TX	2	0	2	0	-	236	-	94	182	109,926
Total	34	1	20	8	186	4,038	2,023	1,739	1,638	416,235
					SIC 29: Petroleum and Coal Products					
LA	8	0	3	4	-	201	2,499	54	29	47,242
CA	2	0	0	0	-	-	-	205	171	29,212
IL	2	0	0	2	-	-	151	93	163	29,361
MN	2	0	1	1	-	109	106	29	59	5,540
TX	2	0	2	0	-	1,857	-	194	38	102,101
Total	18	0	7	7	0	2,258	2,756	2,074	1,600	321,098
					SIC 33: Primary Metals Industries					
WI	5	0	3	2	-	592	360	6	85	3,577
AL	3	0	2	1	-	1,019	37	11	40	5,984
OH	3	0	2	2	-	37	384	29	54	13,659
TN	3	0	1	2	-	197	338	9	13	3,239
AR	2	1	0	1	406	-	749	7	11	1,728
IN	2	0	1	1	-	54	36	18	58	16,871
OR	2	0	0	2	-	-	571	5	16	1,367
SC	2	1	1	0	2	347	-	11	8	757
VA	2	0	1	1	-	798	296	4	24	1,001
Total	31	2	14	15	409	4,154	3,063	287	1033	150,948
					SIC 37: Transportation Equipment					
AL	4	2	2	0	158	342	-	6	6	168
Total	7	2	3	0	158	1,422	0	355	669	2,6754
Particulate matter (PM_{10})										
					SIC 26: Paper and Allied Products					
AL	6	1	2	3	46	284	1,078	19	22	10,367
WI	5	0	5	0	-	211	-	51	75	1,307

continues

TABLE 3-2 Continued

	Number of Permits				Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	Emissions
Particulate matter (PM_{10}) *continued*										
					SIC 26: Paper and Allied Products (continued)					
GA	3	0	2	1	-	55	17	25	17	12,643
LA	3	0	2	1	-	994	4	12	14	8,631
KY	2	0	0	1	-	-	603	9	17	716
NC	2	0	0	2	-	-	801	14	34	4,608
Total	28	1	15	11	46	2,399	3,027	543	728	85,440
					SIC 28: Chemicals and Allied Products					
FL	15	0	7	7	-	651	587	69	42	1,306
LA	6	1	4	0	14	184	-	16	82	6,882
AL	4	0	1	2	-	13	262	12	50	1,762
KY	4	0	2	1	-	111	131	11	59	1,563
Total	36	1	18	13	14	1,044	3,524	1,733	1,769	80,166
					SIC 29: Petroleum and Coal Products					
LA	8	0	3	5	-	46	419	54	26	5,337
IL	2	0	0	2	-	-	18	93	196	5,999
TX	2	0	2	0	-	207	-	194	38	8,954
Total	14	0	6	7	0	280	437	2,074	1,709	53,767
					SIC 33: Primary Metal Industries					
WI	11	0	6	7	-	255	230	6	90	3,185
TN	4	0	1	2	-	475	160	9	16	3,096
AL	3	0	2	1	-	132	6	11	72	8,513
AR		1	1	1	247	4	108	7	10	424
OH	3	0	2	2	-	21	389	29	92	13,296
VA	3	0	1	2	-	135	64	4	23	1,426
IN	2	0	1	1	-	24	22	18	69	9,363
NC	2	0	2	0	-	238	-	1	24	391
SC	2	1	2	0	2	84	-	11	7	368
Total	43	3	20	21	354	1,429	1,391	290	1,134	114,932
					SIC 37: Transportation Equipment					
AL	2	1	1	0	41	37	-	6	10	225
Total	4	2	1	1	47	37	13	342	695	7,424
Sulfur dioxide										
					SIC 26: Paper and Allied Products					
AL	6	0	1	4	-	799	2,660	19	18	33,294
NC	3	0	1	2	-	5,277	5,729	14	26	20,766
FL	2	0	1	1	-	241	40	10	11	26,260
GA	2	0	2	1	-	203	5	25	17	55,075

TABLE 3-2 Continued

	Number of Permits				Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	Emissions
Sulfur dioxide *continued*										
					SIC 26: Paper and Allied Products (continued)					
WI	2	0	2	0	-	435	-	51	76	66,055
Total	22	0	9	10	0	8,346	9,107	543	592	496,155
					SIC 28: Chemicals and Allied Products					
FL	13	0	4	8	-	2,787	18,219	69	30	35,453
AR	2	0	0	1	-	-	10,085	8	11	11,525
LA	2	0	2	0	-	8,516	-	16	60	56,819
Total	22	0	10	11	0	12,299	30,207	1,715	1,174	532,117
					SIC 29: Petroleum and Coal Products					
LA	4	0	2	2		874	1,995	54	22	76,080
CA	2	0	0	0		-	-	205	95	29,875
IL	2	0	0	2		-	305	93	125	125,222
TX	2	0	2	0		91	-	194	37	90,754
Total	11	0	5	4		1,005	2,300	2,074	1,444	569,478
					SIC 33: Primary Metal Industries					
WI	4	0	2	2	-	251	104	6	77	1,360
AL	3	0	2	1	-	734	0	11	48	19,169
OH	3	0	1	2	-	685	77	29	51	190,521
TN	3	0	1	2	-	122	560	9	9	6,419
AR	2	1	0	1	791	-	296	7	9	31,981
IN	2	0	1	1	-	39	20	18	68	33,368
SC	2	1	1	0	0	193	-	11	8	3,597
VA	2	0	1	1	-	596	100	4	22	5,590
Total	27	2	11	13	792	3,486	1,224	287	767	610,893
					SIC 37: Transportation Equipment					
AL	1	0	1	0	-	3	-	6	3	354
Total	1	0	1	0	0	3	0	342	427	40,094
Volative organic compounds										
					SIC 26: Paper and Allied Products					
WI	11	0	6	4	-	537	299	51	108	14,534
AL	5	1	1	3	637	140	327	19	26	25,541
AR	3	0	2	0	-	593	-	8	7	9,333
GA	3	0	0	0	-	-	-	25	23	10,913
LA	3	0	2	1	-	957	2,624	12	15	14,325
MN	3	0	2	0	-	543	-	11	19	5,530
NC	3	0	1	2	-	24	817	14	38	10,001
FL	2	0	1	0	-	64	-	10	13	4,203

continues

TABLE 3-2 Continued

	Number of Permits				Permitted Emissions (tpy)			Census	Emissions	
State	Tot	Grn	New	Mod	Grn	New	Mod	Plants	Plants	Emissions
Volative organic compounds ***continued***										
					SIC 26: Paper and Allied Products (continued)					
KY	2	0	0	2	-	-	2,926	9	23	2,653
Total	39	1	17	14	637	4,094	7,144	543	930	203,827
					SIC 28: Chemicals and Allied Products					
AL	5	0	1	2	-	4	186	12	45	29,171
LA	5	1	2	2	12	67	108	16	96	36,533
KY	3	0	1	1	-	556	369	11	72	14,434
TX	2	0	2	0	-	113	-	94	195	70,873
Total	22	1	9	10	12	945	2,877	1,746	2,076	372,390
					SIC 29: Petroleum and Coal Products					
IL	2	0	0	2	-	-	6	93	153	16,976
TX	2	0	2	0	-	157	-	194	39	79,617
Total	6	0	3	2	0	161	6	2,074	1,610	254,230
					SIC 33: Primary Metal Industries					
WI	7	0	2	5	-	109	212	6	89	2,980
IN	3	0	2	1	-	22	38	18	78	10,423
SC	3	1	1	0	2	71	-	11	8	684
TN	3	0	0	2	-	-	449	9	14	1,868
VA	3	0	1	2	-	303	272	4	27	3,492
AL	2	0	1	1	-	307	1	11	64	9,181
OH	2	0	0	2	-	-	562	29	49	4,754
Total	31	1	10	18	2	1,361	2,078	291	1,097	103,323
					SIC 37: Transportation Equipment					
MI	7	0	5	1	-	2,935	65	35	154	25,082
AL	3	2	0	0	1,386	-	-	6	28	1,181
WI	2	0	1	1	-	79	232	9	54	5,261
Total	18	4	7	3	2,171	4,223	663	355	1,237	125,425

[a]NSR permit data are unofficial from EPA—preliminary, unpublished, not subjected to review, or not distributed outside EPA; this may not be a complete list of all NSR permits obtained in 1997-2002.

NOTE: Table lists only states with five or more NSR permits in manufacturing plants, but totals are for all states.

ABBREVIATIONS: Census plants = number of establishments in manufacturing industries in state, taken from 1997 Economic Census; emissions = 1997 EPA point-source emission data (unpublished, not 1996 NEI data), includes number of plants with any emissions of this pollutant and total emissions; Grn = Greenfield; Mod = modification; New = new unit at existing plant; Tot = total; tpy = tons per year.

Louisiana and Kentucky. In general, permitting activity for modifications is distributed among a number of industries and states. The key inferences from the available data suggest that the following industries have substantial NSR permitting activity for modifications, whether measured in terms of the number of permits or permitted emissions: electricity generation; paper and allied product; and chemicals and allied products. Other industries that appear to be of secondary importance with respect to permitting activity include stone, clay, and glass products; primary metal industries; and food and kindred products.

Although the mix of industries appears to be widely different, the emission processes are often qualitatively similar across industries. For example, many industries use common unit operations, such as industrial furnaces, to generate steam for process use. Some industries—such as stone, clay, and glass products—use tunnel or rotary kilns, which are specialized combustion-based equipment for heating specific types of materials (EPA 1995a). Thus, although the specific design and duty cycle may differ, there are similarities in combustion principles and factors that govern pollutant formation and control. For example, the NO_x formation mechanisms and control strategies are similar for cement kilns, glass melting, and industrial boilers and include thermal and fuel NO_x formation (if a nitrogen-bearing fuel is used), combustion-based controls, and postcombustion controls (EPA 1994a,b,c). Of course, not all the emission sources are combustion based. To provide a more-thorough assessment of specific emission technologies, later sections of this chapter review specific types of process facilities and their unit operations.

Several states provided summary information to the committee regarding NSR, but the summaries typically did not distinguish among permits for new sources and permits for modifications of existing sources, so permitting activity for modifications cannot be readily inferred from the information. For example, in Louisiana, the largest share of all permits was issued for chemical manufacturing, power generation, refining, paper and allied products, and inorganic-chemical industries. The industrial mix in Louisiana is somewhat unusual because of the large industrial presence in such areas as those around the lower Mississippi River and Lake Charles. In New Jersey, permits have been issued for power generation, chemical and allied industries, petroleum refining, and others. The sources permitted in New Jersey have included combustion turbines, boilers, engines, and fluidized catalytic cracker units. However, the industries identified in the Louisiana and New Jersey surveys as being of greatest importance with respect to permitting activity are qualitatively consistent with those identified in the EPA summary.

The use of data such as in Appendix D is one approach to identifying priorities among industries subject to NSR for modifications. However, another approach is to select industries that illustrate the complexity of the technology choices that are associated with decisions regarding common repairs and replacements. Furthermore, some industries are regionally important. For example, the petroleum-refining and pulp and paper industries provide useful case studies regarding the myriad of unit operations that are subject to repairs and replacement. Such industries also illustrate that many unit operations or processes are common to multiple industries. For example, industrial boilers are commonly used to boil water to produce steam in many industries. In addition to industrial boilers, industrial process heaters are used to heat raw materials, such as crude oil or intermediate products for processing or distillation. Industrial heaters often exhibit emissions that are similar to those from industrial boilers. The fuel used for industrial heaters and boilers differs among industries. Natural gas is predominant in the chemical industry, fuel gas and natural gas in petroleum refining, and coal, tire chips, “bark” (waste wood, such as stumps), and “black liquor” (lignin that has been separated from cellulose) in the pulp industry. On the basis of review of available summaries of data on permits and the evaluation of other factors, such as representativeness of the complexity of technology characteristics and options, several industries and emission sources were identified as having high priority for characterization and evaluation, including electricity generation, petroleum refining, and paper and allied products. Furthermore, because industrial boilers are common to many industries, they are also characterized.

Systematic data are not available from which to assess the claim of foregone opportunities for facilities that are claimed to have refrained from making modifications for fear of triggering a requirement to obtain an NSR permit. Anecdotal examples were presented to the committee, but there are often inadequate details on the examples. Furthermore, the committee cannot use anecdotes as the basis of generally valid inferences.

The committee also considered use of the generating availability data system (GADS) produced by the North American Electric Reliability Council (NERC). The GADS includes design data, and performance and event data. The former are publicly available, and the latter are available only with special permission. The publicly available design data provide information regarding overall average rates of the forced and scheduled outages, as well as deratings, for power plants. Also, summary data regarding the top 25 individual “cause codes,” which briefly indicate the reason or purpose of the outage, are available. That information provides insight regarding failures or replacement activities at power plants (for example, the largest sources of average megawatt (MW) hours lost per outage for fossil-fuel-fired power plants of 300-399 MW capacity included major turbine overhaul, major boiler overhaul, and various forms of generator overhaul) but does not directly provide insight regarding choices to forego opportunities that might have prevented or reduced the frequency of some of these occurrences.

There are several key conclusions from the review of permitting activity. Most permits are for greenfield facilities or new facilities at existing locations. Permits for modifications involve only 1-2% of total emissions for most pollutants in either the manufacturing or electricity-generating sector (including facilities that did not receive a permit in that period). There is somewhat more permitting activity for modifications, as measured by emissions and number of permits, in the manufacturing sector, but the activity in the two sectors is often of a similar order of magnitude. Although there are systematic data available from which to make assessments of permitting activity, no systematic data available from which to assess the opportunity costs of facility decisions not to make modifications.

STATE PERMITTING PROGRAMS—STATUS OF NEW SOURCE REVIEW IMPLEMENTATION

The purpose of this section is to provide an overview of the current status of NSR implementation. Because there is no national clearinghouse on NSR permitting activity or the status of the NSR permitting programs in each state, the committee asked the State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA/ALAPCO—referred to in this report as STAPPA) about the current state of NSR implementation. STAPPA provided the following types of information from state and local agencies:[4]

- Format in which data are archived for major and minor air permits, including NSR. Formats include paper files, electronic databases, and others.
- Key industries in the state in terms of emissions and permitting activity.
- Descriptions of electronic databases of emission and permit data, such as data categories and the period over which records are kept.
- Status of NSR implementation, including whether the state is implementing the NSR reforms, implementing the prerevision NSR, or implementing a hybrid that includes combinations of both. Furthermore, comment was requested as to the state's future plans.

There are several key findings from the information provided by STAPPA. There is no consistency in how permits are archived or how such information can be retrieved. For example, some states, such as Alabama

[4]Personal communications, M. Stewart Douglas, STAPPA, 2005.

and Iowa, have primarily a paper-based system, and other states, such as Alaska, Mississippi, and Maryland, have various types of electronic approaches. Some of the latter involve converting permit files to electronic format and posting them on the internet, and others involve the use of electronic databases to store permit tracking data or emission data. It would be difficult and time consuming to do a systematic survey of the permits themselves given the lack of uniformity of the archival method and the format in which information is stored.

The states that reported the status of their NSR programs essentially confirmed information provided in Chapter 2 regarding how the "unapproved" versus "approved" states handle their NSR programs. *Unapproved* here refers to states that are either "not approved but delegated" (often referred to simply as *delegated*) or "not approved and not delegated." For an approved state, the NSR program is approved as part of the state implementation plan (SIP), so the state fully administers the NSR program. For a "not approved but delegated" state, EPA allows the state to do the day-by-day work of running the program, but the state is ultimately subject to EPA supervision.

For example, Alaska has adopted the new federal NSR rules by reference, whereas Alabama continues to use the prerevision NSR rules. Many states reported that they are awaiting finality on the federal rules given the uncertainty caused by litigation pertaining to the NSR reforms. In short, there is wide variation in the current status of NSR among the states. Because many states have not fully implemented the NSR reforms and because the reforms are relatively recent, there is little or no track record of permitting under the reforms. In turn, there is little empirical basis on which to assess the effect of the reforms. The available information is anecdotal and incomplete. A key logistical aspect of permitting under the reform is to require companies to provide data to support their claims regarding use rates under the baseline part of the rule.

As a followup, several members of the committee obtained additional information from permitting officials in several states, including Illinois, Kentucky, Michigan, New Jersey, New Hampshire, Ohio, and Washington.[5] It appears from the comments of those officials that the NSR rule changes have not yet had a substantial effect. In many cases, the same or similar outcome is reported under the prerevision and revised NSR rules. In some cases, state regulators have advised industries to apply under the prerevision rules or the industry has preferred to do so because of the greater familiarity and certainty associated with the prerevision process. Some companies voluntarily retrofit emission controls to make them similar to what would

[5]Information was obtained via teleconference calls among several committee members and state permitting officials during October 2005.

be required under NSR or agree to restrictions to avoid emission increases associated with a modification that would trigger NSR. The uncertainty about the legal status of the new rules may also be inhibiting their use and causing a preference for the prerevision rules where possible. One state commented that the equipment replacement provision (ERP) would be difficult to implement because it would require financial accounting capabilities that the state environmental agencies typically do not have.

In many states, facilities need to get a minor state permit for construction even if they do not need an NSR permit. The minor permits often include requirements for control technology similar to that required under NSR, such as BACT. Thus, it is possible in some states that facility changes that might not trigger NSR could trigger the need for a minor permit, which in some cases might be of equivalent stringency. Getting a minor permit instead of an NSR permit appears to be generally more desirable to facilities because of the greater delays and expense associated with the NSR permit process, which can involve long public comment and greater documentation than a minor permit.

Some states are using a common electronic database system that assists in processing permit applications, tracking permits, and filing documents. Seven states are using it or considering using it: Kentucky, Mississippi, New Mexico, Louisiana, New Jersey, Indiana, and Maryland.

In summary, there is substantial variation among states regarding the implementation status of NSR reforms, the existence of a minor permitting program that might cover modifications that are not covered under the NSR reforms, experience with reforms where they have been implemented, and the recording and archiving of information. There is some promise that several states are adopting a common framework for electronic management of permits. There appears to be some reluctance by some states and even some facilities to conduct permitting under the new rules until the uncertainty associated with litigation over the reforms subsides. Thus, a complicated context surrounding the state of evidence regarding the effects of NSR revisions makes it difficult to conduct a systematic empirically based assessment.

PROCESS TECHNOLOGIES OF EMISSION SOURCES: PROCESS DESCRIPTION, REPAIRS AND REPLACEMENT, AND POLLUTION-PREVENTION AND -CONTROL APPROACHES

The purpose of this section is to describe the major components of emission sources that are most relevant to NSR permitting decisions pertaining to repair and replacement. An understanding of the typical facilities in several key industries is needed to assess the effect of changes in NSR on emissions and energy use from these sectors. Thus, the focus is on components that are most commonly subject to common repair and the potential for more substantial replacements. Typical pollution-prevention and -control strategies are also identified. Because the number of industries affected by NSR is potentially large, it was deemed infeasible to provide a comprehensive survey of all industries. However, selected industries that either represent a high frequency of permitting activity or contain emission processes typical of many industries are reviewed here. For example, electricity-generating power plants are among the source categories for which there is a relatively high frequency of NSR permits associated with modifications. Other industries, such as petroleum refining and paper, are important in selected regions of the country. However, those types of industries include emission processes, such as industrial furnaces, that are common to many industries. Thus, the review provided here is intended to furnish a technical foundation for identifying issues pertaining to typical repair and replacement and their implications for cost, emissions, and other effects.

There are no standard ways among industries of reporting process design, repair, and replacement practices, and performance and cost information. Classification schemes may differ among industries because of differences in feedstocks, process configurations, and constituent unit operations and because of industry-specific practices and metrics. Thus, in presenting information regarding specific industries in later sections of this chapter, we tend to adhere to terminology, flowsheets, repair and replacement practices, and technology options that are tailored to these industries. For each of the industries described here, there is a representative flowsheet of the process technologies and a narrative that highlights key NSR-relevant technological characteristics.

Electricity-Generating Facilities

According to 2002 national emission estimates, electricity-generating facilities each year emit about 4.7 million tons of NO_x, 10.3 million tons of SO_2, 52,000 tons of VOCs, 499,000 tons of CO, and 582,000 tons of $PM_{2.5}$ (EPA 2004e). Most electricity-generating facilities' NO_x emissions are from coal-fired power plants, including bituminous- and subbituminous-coal plants, and natural-gas-fired plants. SO_2 emissions are primarily from bituminous-coal-fired plants, with smaller contributions from other ranks of coal and from other fuels. VOC emissions from power plants tend to be lower than from other sources because of the high combustion efficiency relative to other types of energy-conversion systems (such as internal-combustion engines) and because evaporative emissions at other sources contribute to national totals. Similarly, CO emissions from electricity-generating facilities are a small fraction (<1%) of national emissions and are associated mostly with coal and natural gas. Coal accounts for most of the estimated $PM_{2.5}$

emissions from electricity-generating facilities, which in turn represent less than 10% of the estimated national $PM_{2.5}$ emissions. However, these data are for primary emissions and do not include formation of secondary $PM_{2.5}$ in the atmosphere. Key pollutants of concern for electricity-generating facilities from a health perspective tend to be NO_x and SO_2 because they are important contributors to concentrations of airborne $PM_{2.5}$ and ozone (see Chapter 7). Coal and natural gas are the fuels of greatest interest with respect to this mix of key pollutants. Therefore, this section focuses on identifying the characteristics of typical coal-fired and natural-gas-fired electricity-generating facilities for purposes of identifying the typical repair and replacement issues for such facilities.

Typical Electricity-Generating Power-Plant Designs

There are many varieties of power-plant design for both coal- and natural-gas-fueled systems. For example, for coal-fired power plants, the choice of an appropriate furnace design and the design of other plant components often depends at least to some extent on the rank of the coal and its properties. The choice of furnace design can influence baseline emission rates. For example, tangentially fired furnaces promote the formation of a rotating fireball in a furnace, so their NO_x emissions are different from those from a wall-fired boiler. Operational practices, such as optimization of fuel and air ratios, also influence emissions; a well-tuned furnace can have substantially lower NO_x emissions than one that is not well tuned.

Figure 3-1 illustrates a generic power plant burning pulverized coal that is equipped with postcombustion controls for NO_x, PM, and SO_2. The

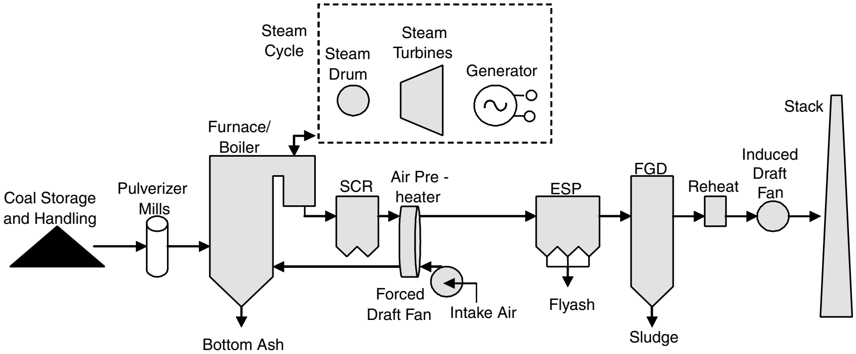

FIGURE 3-1 Simplified flowsheet for generic pulverized coal-fired electricity-generating power plant with postcombustion controls for NO_x, PM, and SO_2.

plant includes coal storage and handling facilities and pulverizer mills that typically deliver finely pulverized coal to the burners via a pneumatic transport system. The furnace, also often referred to as a boiler, is the structure where combustion of the coal takes place. The burner design and methods for staging combustion affect the formation of NO_x.

The walls of the furnace structure typically are composed of steam tubes, so most of the surfaces in the furnace are actually heat exchangers. Therefore, the flue-gas temperatures decrease as the fuel gas leaves the flame zone and travels past the heat-exchanger tubes. The topmost portion of the boiler is referred to as the "convective pass" and includes the heat exchangers for producing superheated steam. The temperature window in portions of the convective pass can be appropriate for selective noncatalytic reduction (SNCR), which is an NO_x-control technique involving injection of ammonia or urea to promote conversion of NO_x in the flue gas to molecular nitrogen (e.g., EPA 2002d). After the convective pass, at which point the flue-gas temperature has been reduced because of heat exchange, the flue gas reaches the economizer, which is also a heat exchanger.

The flue gas leaving the economizer is typically about 367°C, which is compatible with the desired temperature window for selective catalytic reduction (SCR) for postcombustion NO_x control (e.g., EPA 2002d). Flue gas leaving the SCR, if present, or the economizer, if SCR is not present, flows through the air preheater, which is a heat exchanger. A typical air-preheater design is a slowly rotating basket, portions of which are exposed to the hot flue gas and then the cooler inlet air. An intake-air fan is typically used to force air into the furnace. In some power-plant designs, an induced-draft fan downstream pulls gas through the system.

The flue gas leaving the air preheater is typically at about 147°C, which is appropriate for a "cold-side" electrostatic precipitator (ESP) or a fabric filter, either of which is used to capture a high percentage (typically 99% or more) of the fly ash entrained in the flue gas. If a power plant is equipped with a flue-gas desulfurization (FGD) system, also commonly referred to as a scrubber, the FGD system is typically downstream of the fly ash collection device. A common design for FGD systems is a spray tower in which a slurry of limestone is sprayed into the flue gas, promoting contact of the gas with liquid droplets containing dissociated limestone (Cooper and Alley 1994; DeNevers 2000). There are numerous other FGD system designs, such as dry systems. FGD systems are also classified as throwaway (if there is a substantial waste stream) or regenerative (if the sorbent is regenerated and reused in a continuous cycle). For illustrative purposes, we focus on wet limestone FGD because it is one of the more common designs. SO_2 is soluble in water; however, the effect of a calcium-based additive is to promote dissociation in the aqueous phase, which has the effect of "pulling" more SO_2 in solution than would otherwise occur. The spray tower thus promotes the absorption of SO_2 to facilitate aqueous-phase chemistry that produces calcium sulfite or calcium sulfate. A forced-oxidation variation of the limestone-based FGD promotes a larger conversion toward calcium sulfate, which is a more desirable product for handling. If sufficiently purified and dewatered, the calcium sulfate from an FGD system can be used to make gypsum wallboard, although in many applications the sludge that includes calcium sulfate is ultimately disposed of in a settling pond or landfill. Because the spray tower also promotes some evaporation of water from the slurry when contacted with the warm flue gas, the temperature of the flue gas typically drops to about 47°C. To promote sufficient buoyancy of the flue gas for flow through the stack and some amount of plume rise, the relatively cool flue gas leaving the spray tower is generally reheated to about 77°C or higher. Reheating can be adjusted as needed by the plant operator in response to visual observation of plume buoyancy.

The other major components are part of the steam cycle. Some of the critical elements of the steam cycle are steam drums, steam turbines, generators, and associated pumps and piping. The plant includes a transmission system to deliver power to high-voltage power lines. The balance of the plant typically includes many items of auxiliary and support equipment and facilities, such as the control room, administrative and storage buildings, shops, roads, rail, and others.

The thermal efficiency of pulverized coal-fired power plants are typically about 35% for subcritical steam cycles, with variations that depend on details of the design, age, operating strategies, maintenance practices, major overhauls, repowering, ambient conditions, fuel quality, and other factors. The thermal efficiency of such plants has not changed dramatically over time. The prospect of increased use of supercritical steam cycles may lead to a marginal increase in efficiency for a new plant. Alternative technologies, such as integrated gasification combined cycle (IGCC) systems, may also be capable of providing some efficiency improvement compared with existing subcritical steam cycle plants (Frey and Zhu 2006). However, without a dramatic increase in thermal efficiency, it appears to be the case that many producers of electric power do not have a major economic incentive to replace existing plants with newer ones, as long as the existing plants can be operated with adequate reliability and competitive marginal costs. A typical natural-gas-fired gas turbine combined-cycle system is illustrated in Figure 3-2. The configuration shown is for a system with SCR for postcombustion NO_x control. A gas turbine has three main components: compressor, combustor, and turbine (also referred to as an expander). The compressor increases the pressure of ambient air for delivery into the combustor, where pressurized gaseous fuel (typically natural gas) or liquid fuel is introduced. The high-pressure, high-temperature combustion products enter the turbine via an inlet nozzle, and as the gases are expanded and cooled,

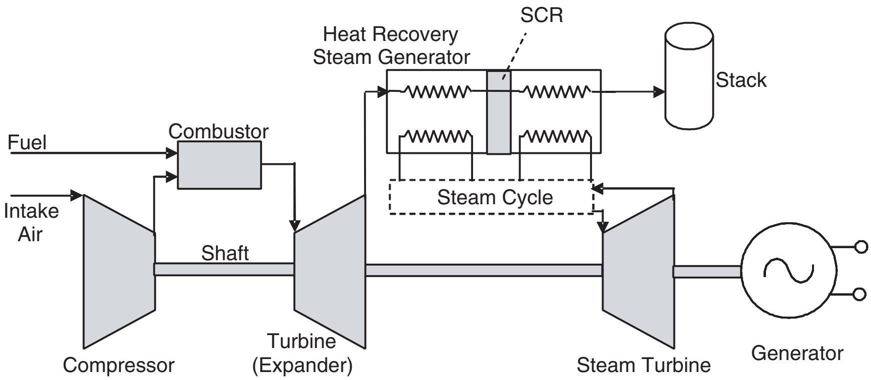

FIGURE 3-2 Simplified schematic of typical natural-gas-fired gas turbine combined-cycle system.

energy is transferred to rotate a shaft. Much of the shaft work is used to turn the compressor, and the balance is available for turning a generator. In some designs, a steam turbine is on the same shaft, and the gas and steam turbines turn the same generator.

The gases leaving the expander of a typical heavy-duty gas turbine have a typical temperature of 597°C. Thus, additional thermal energy can be recovered from the exhaust gas via a heat-recovery steam generator (HRSG). The HRSG is composed of multiple heat exchangers that serve tasks ranging from heating boiler feedwater to superheating steam. Steam typically is produced at two or three pressures to feed multiple stages of the steam turbine. Because SCR requires a specific temperature window, it is typically located in the HRSG so that the exhaust gas that passes through it is at an appropriate temperature during normal operations.

Repair and Replacement Considerations at Electric Power Plants

This section reviews the typical repair and replacement considerations for electricity-power plants, with a primary focus on coal-based power plants and secondary consideration of natural-gas-fired combined-cycle systems. The types of activities reviewed here are related to typical industry practice but are not evaluated here with respect to implications for NSR. A given repair or replacement activity may or may not trigger a requirement for an NSR permit, depending on the specifics of each case.

Key elements of repair and replacement at a typical fossil-fuel-fired steam power plant are the following (Babcock and Wilcox 1978):

- Safety considerations: These often involve proper operation of various monitoring, observation, and detection systems, such as burner observation, flame failure, unburned combustibles, fuel:air ratios, water levels, feedwater and boiler conditions, pressures, and temperatures.
- Outages: These are scheduled outages for preventive maintenance (in the colloquial sense).

—Internal cleanliness and inspection (for example, measuring internal boiler-tube deposits and chemical or acid cleaning of tube internals).

—External cleanliness and inspection (for example, for external fouling not removable by normal sootblowing; external signs of pending tube failure, such as blistering or warping, signs of erosion or corrosion, misalignments, and deposits of ash or slag; condition of equipment; and condition of exposed refractory).

—External cleaning (e.g., water washing of sulfur-bearing ash deposits).

—Identification of needed corrective actions (for example, preventing recurrence of problems identified during inspection, such as startup procedures that are too rapid and lead to overheating of superheater tubes).

- Cleaning of internal heating surfaces (for example, with chemical cleaning techniques).
- Repairs.
- Care of idle equipment.

Specific areas of a typical coal-fired power plant that require repair and replacement include the following (ERCC 2002):

- Boiler-tube assemblies
- Air heaters
- Fans
- Mills and feeders
- Turbines and generators
- Condensers
- Control systems
- Coal and ash handling
- Feedwater heaters
- Sootblowers and water lances
- Burners
- Motors
- Electric equipment
- Pumps
- Piping, ducts, and expansion joints
- Air compressors

A summary of common repair and replacement activities for each of those areas is given in Appendix E in Table E-1.

Many of the common repair and replacement requirements at coal-fired power plants are attributable to exposure of key components to the erosive effects of ash or other solids during fuel handling or in the flue-gas stream; the corrosive effects of acid gases in the flue-gas stream; and impurities, such as in steam. Wear and tear on turbine blades, heat-transfer surfaces, and other components can lead to a loss of system efficiency, reliability, capacity, or some combination of the three. Thus, common repair and replacement activities are often aimed at attempting to maintain the original efficiency, reliability, or capacity of the plant. Over time, new designs or materials may become available for replacement parts, such as turbine blades, and potentially offer improved efficiency, reliability, or capacity compared with the original equipment used in the plant. It may be easier, more economical, or more energy-efficient to use the more recently available replacement parts than to attempt to create the original parts. Many repair or replacement projects also can prevent more catastrophic failure of a plant. For example, replacing worn heat-exchanger tubes potentially could prevent a catastrophic failure that could substantially damage a plant or injure personnel. Similarly, replacing worn turbine blades before they break and are "ingested" by other parts of the turbine can avoid a more massive failure of the turbine. Thus, there is clearly a role for preventive repair and replacement to maintain the safety of a plant and for prudent timing of replacement of worn or damaged parts or components of the plant to maintain efficiency, reliability, and capacity.

The costs of repair and replacement projects typically are higher on a per-unit-capacity basis for smaller units than for larger units. Thus, the percentage of the total plant cost represented by a particular type of repair project typically may be larger for smaller units than for larger units.

Many of the common repair and replacement activities summarized in Appendix E occur at a large proportion of coal-fired furnace units and represent costs that are a relatively small fraction of total initial plant cost, considering the latter is on the order of $1,000/kW or more. Appendix E does not attempt to summarize less frequent major replacements at a plant, such as repowering with a new furnace using an existing steam cycle or replacing major components (such as a turbine-generator) with an entirely new system.

Typical Air-Pollution-Prevention and -Control Approaches for Electric Power Plants

Air-pollution-prevention and -control options for coal-fired power plants typically focus on emissions of PM, NO_x, SO_2, and mercury (Hg).

Control of Hg emissions is a recent development, necessitated by the 2005 Clean Air Mercury Rule (CAMR); there is no standard Hg emissions-control technology, although Hg-adsorption and -oxidation technologies have been extensively tested. For natural-gas-fired gas turbine-based systems, NO_x emissions are usually of primary concern, and emissions of other pollutants, such as CO and VOCs, are of secondary concern. There is often a tradeoff between NO_x prevention with combustion-based approaches (for example, wet injection and low-NO_x burners) and emissions of products of incomplete combustion, such as CO and VOCs. Changes into the combustion process, such as lower flame temperatures, that prevent a portion of NO_x emissions can lead to reduced combustion efficiency. However, most of this section focuses on coal-based systems.

Typical control options for PM include cold-side ESPs and fabric filters. For NO_x, control options are typically classified as combustion based or postcombustion. Combustion-based approaches typically include low-NO_x burners, overfire air, and other methods aimed at staging combustion to prevent at least some conversion of fuel-bound nitrogen to NO_x while preventing at least some creation of thermal NO_x from nitrogen in the combustion air. Postcombustion approaches typically involve injecting a reactant, such as ammonia, to react with NO_x in the flue gas, either without a catalyst (SNCR) or with a catalyst (SCR). To be effective, SNCR requires a specific temperature window, typically found in the convective pass of the boiler, and excellent mixing of ammonia (or other reagents, such as urea) with the flue gas. SCR operates at a lower temperature window, typically in a dedicated reactor downstream of the economizer heat exchanger. Detailed reviews of NO_x control-technology options are available elsewhere (EPA 1994a,b,c).

For SO_2, the typical control options are to switch to a low-sulfur fuel or to use postcombustion control in the form of FGD. Switching to a low-sulfur fuel often requires changes elsewhere in the plant. For example, when switching from a bituminous to a low-sulfur subbituminous coal, it is often necessary to modify the pulverizer mills. Furthermore, because the electric resistivity of fly ash from subbituminous coal can differ from that of bituminous coal, retrofits to an ESP (if present) are often required. Thus, a fuel switch can entail some capital cost associated with changes within a plant.

For background information, a budgetary cost analysis of typical NO_x and SO_2 control technologies applied to generic types of new coal-fired power plants was conducted. The analysis of NO_x control-technology costs is predicated on generic types of coal-fired electricity-generating furnaces as summarized by EPA (1994d). Examples of generic types of furnaces are wall-fired, tangentially fired, wet-bottom wall-fired, cell, and cyclone types. For each type of furnace, a typical uncontrolled-emission range and best estimate were reported by EPA, depending on whether the furnace was built before New Source Performance Standards (NSPS), under the Subpart D NSPS

TABLE 3-3 Typical Uncontrolled NO_x Emissions by Furnace Type for Coal-Fired Electricity-Generating Plants in the United States

	Typical Uncontrolled NO_x Emissions (lb of $NO_x/10^6$ Btu, reported as NO_2)					
	Pre-NSPS		Subpart D		Subpart Da	
Type of Furnace	Typical Range	Best Estimate	Typical Range	Best Estimate	Typical Range	Best Estimate
Tangentially fired	0.4-1.0	0.7	0.3-0.7	0.6	0.3-0.5	0.5
Dry-bottom wall-fired	0.6-1.2	0.9	0.3-0.7	0.6	0.3-0.6	0.5
Wet-bottom wall-fired	0.8-1.6	1.2				
Cell	0.8-1.8	1.0				
Cyclone	0.8-2.5	2.0				

SOURCE: EPA 1994d.

or under the Subpart Da NSPS. The estimates are summarized in Table 3-3. According to EPA (1994d), no boilers of the wet-bottom wall-fired, cell, or cyclone designs have been built since promulgation of applicable NSPS. Table 3-3 is useful in providing a baseline for uncontrolled emission rates that can be used to assess the overall effectiveness of pollution-prevention and pollution-control strategies that reduce emissions. In practice, a typical power plant has one or more methods for source reduction or control of NO_x emissions and therefore has emissions lower than the uncontrolled rates shown in Table 3-3.

To illustrate the cost effectiveness of NO_x control, which is typically reported in dollars of levelized cost per ton of NO_x emissions avoided, a sensitivity analysis was conducted with the EPA Acid Rain Division NO_x Control Technology Cost Tool,[6] which is a spreadsheet-based model (EPA 2002e). Levelized cost includes annualized cost recovery for capital cost plus annual fixed and operating costs and is expressed in dollars per year. The annual emission reduction is in tons per year. Therefore, cost effectiveness has units of dollars per ton of emission reduction. To run the model, the user must specify the type of boiler (tangentially fired, wall fired, and so on), the capacity of the boiler in megawatts of electricity generated, the capacity factor (ratio of actual kilowatt hour [kWh] generated to the total possible kWh that could be generated if the plant ran at 100% load all year), and the uncontrolled NO_x emission rate. The software provides results like those summarized in Table 3-4 for two case studies based on a tangentially fired

[6]The algorithm was used mainly to illustrate the sensitivity of cost to various key factors; other cost estimates can be obtained by using another EPA costing algorithm (EPA 2004f) or the Integrated Environmental Control Model (Rubin et al. 1997).

TABLE 3-4 Example of Average Cost-Effectiveness Estimates for Electricity-Generating Boiler NO_x Control for Generic Tangentially Fired Furnace: Comparison of Average Cost Effectiveness for Different Sizes and Capacity Factors

		Cost Effectiveness, $/ton	
Control Option[a]	Emission Rate, lb of $NO_x/10^6$ Btu, Reported as NO_2	100-MW Boiler at 30% Capacity Factor[b]	600-MW Boiler at 75% Capacity Factor
Uncontrolled	0.70	—	—
LNC1	0.40	4,600	260
LNC2	0.37	3,100	240
LNC3	0.33	3,700	280
SCR	0.14	16,800	780
LNC1 + SNCR	0.24	9,500	620
LNC2 + SNCR	0.22	8,400	590
LNC3 + SNCR	0.20	8,700	610
LNC1 + SCR	0.12	17,200	810
LNC2 + SCR	0.11	16,300	790
LNC3 + SCR	0.10	16,560	820

[a]LNC1, LNC2, and LNC3 are various types of low-NO_x burner designs.
[b]Capacity factor is the ratio of actual kWh generated to the total possible kWh that could be generated if the plant ran at 100% load all year.

boiler with an uncontrolled emission rate of 0.7 lb of NO_x per 10^6 British thermal units (Btu), reported as NO_2.

The two case studies were chosen to represent scenarios that would lead to high values of cost effectiveness, such as for a smaller boiler used for peaking service, versus scenarios that lead to lower values of cost effectiveness, such as for a larger boiler used for baseload service. The purpose of the comparison is to demonstrate the wide range in cost, depending on boiler size and capacity factor. The choice of control options can include combinations of combustion-based and postcombustion options (for example, LNC1 [low-NO_x concentric burners, level 1] with SCR), as shown in the table. The cost effectiveness varies by a factor of 3-5, depending on the case study, with emission reductions of 43-86%.

The cost effectiveness is sensitive to both the uncontrolled emission rate and the capacity factor. For example, the estimated cost effectiveness of NO_x control for a 600-MW boiler with a 75% capacity factor is $200-700 per ton (with corresponding control efficiencies of 43-86%) if uncontrolled emissions are 1.0 lb/10^6 Btu to $700-1,800 per ton if uncontrolled emissions are 0.4 lb/10^6 Btu. At an uncontrolled emission rate of 0.7 lb/10^6 Btu, but with a capacity factor of 0.5, the cost effectiveness, corresponding to the range of control options shown in Table 3-4, is \$600 to more than \$1,500 per ton.

For a wall-fired boiler, a similar set of case studies was conducted, assuming an uncontrolled emission rate of 0.9 lb of NO_x per 10^6 Btu, reported as NO_2. For a 600-MW plant with a capacity factor of 75%, the estimated cost effectiveness of NO_x control ranged from \$110 to \$600 per ton over a range of control efficiencies of 51-89%. For a 100-MW plant with a capacity factor of 30%, the corresponding range of estimated cost effectiveness was \$1,400-13,000 per ton. Control options ranged from low-NO_x burners (LNB) only to combinations of LNB, overfire air, and postcombustion methods of either SCR or SNCR.

Typical capital costs for selected pollution-control equipment for coal-fired power plants are reported by EPA (2002d). For example, the capital cost of SCR is reported to be about \$80 per kilowatt, whereas the capital cost of FGD systems for a typical 500- to 600-MW plant varies from about \$160 to \$210 per kilowatt depending on the FGD system selected. A separate cost analysis performed with the integrated environmental control model (IECM) (Rubin et al. 1997) for a typical 600-MW wall-fired power plant burning bituminous coal produced capital estimates of about \$25 per kilowatt for combustion-based NO_x control, \$40 per kilowatt for SCR, \$120 per kilowatt for FGD, and \$45 per kilowatt for PM control, compared with a total plant cost (including all emission controls) of \$1,280 per kilowatt versus a capital cost of \$1,020 per kilowatt for the base plant excluding controls. The difference in the cost between the base plant and the total plant includes the cost of controls plus additional costs associated with increased auxiliaries, such as ash handling. Thus, the capital cost of installing all the air-pollution controls collectively increases costs by 25% compared with the base plant. However, the costs for any of the controls individually vary from 2.5% to 12%. As an aside, the cost for SCR estimated with the IECM is at the low end of a typical range of reported SCR values for actual installations. However, the installed cost of SCR depends on site-specific factors and the cost of the catalyst, which can fluctuate, thereby leading to interplant variability in SCR cost.

All the cost analyses reported in the preceding paragraphs pertain to a new plant. The costs to retrofit emission controls to existing plants can be considerably higher, depending on site accessibility and whether the retrofit can be accomplished during a scheduled outage without increasing outage time. For example, a common problem encountered in retrofitting an SCR system at an existing plant is to identify a location for the SCR reactor. If there is substantial congestion at the site, the SCR system might have to be placed on top of existing ductwork or other flue-gas handling equipment, requiring a substantially more complex foundation and structure, which is compounded by the difficulty of bringing construction equipment into the congested area to perform the installation. As a rule of thumb, the capital cost of a retrofit can typically be 30-50% more than that of a new plant, but there is considerable variability in the percentage, depending on site-specific factors.

Furthermore, the total effect of control technologies can include changes in overall plant efficiency and changes in fixed and variable operating costs. Thus, the cost analyses here typically represent a lower bound but do illustrate the sensitivity of cost to plant-specific conditions (such as uncontrolled emission rate, plant size, and capacity factor).

Costing algorithms for the capital, annual, and levelized costs of a variety of pollution-control systems are available in EPA's Air Pollution Control Cost Manual (EPA 2002d) and other references, such as documentation of the IECM (Berkenpas et al. 1999). Those algorithms and reported costs for various actual facilities can be used as a basis to evaluate the cost implications of air-pollution-prevention and -control options.

Industrial Boilers and Other Industrial Combustors

Industrial boilers and combustors contribute a diverse collection of processes or devices that supply heat to a larger process or system or that act as thermal oxidizers of waste products. In addition to industrial boilers, there are combustion-based industrial process heaters exhibiting similar emissions. Boilers typically boil water to produce steam. Heaters are used to heat raw materials, such as crude oil, or intermediate products for processing or distillation. The fuel source to industrial heaters and boilers differs among industries with natural gas predominant in the chemicals industry, fuel gas and natural gas in petroleum refining, coal, tire chips, "bark" (waste wood such as stumps) and "black liquor" (lignin that has been separated from cellulose) in the pulp industry.

As is common when addressing emission sources for airborne pollutants, electricity-generating-facility boilers are deliberately excluded from this category. Excluding electric-utility generation, industrial boilers and combustors vary widely in size and purpose. They play a role in many processes and systems that are geographically dispersed. As a result, the potential effect of airborne emissions from industrial boilers and combustors is substantial because they are widely dispersed geographically and equally present in urban and rural airsheds that may or may not be classified as nonattainment areas.

The diverse applications that use nonutility industrial boilers and combustors involve a variety of fuel types, which result in substantial variation in emission profiles. Industrial boilers and combustors constitute substantial sources of four of the six criteria pollutants: NO_x, PM, SO_2, and CO. The process that a particular unit serves determines or strongly influences the boiler or combustor fuel choice, which in turn greatly influences the emission profile. In a petroleum-refining process, flares used to oxidize sulfur in tail-gas streams or combustion-driven process heaters fueled by crude oil with a high sulfur content will produce high sulfur emissions. Pulp and paper processing can use biomass as a combustor fuel, which results in high PM emissions. Because industrial boiler and combustor use is widespread and tailored to specific applications, the potential to emit a particular criteria pollutant or its precursors varies widely, depending on the fuel mix and installed emission controls. In addition, unlike the catalytic converters used to oxidize CO to CO_2 on mobile combustion sources, such controls are rare in large stationary combustion sources. As a result, nonutility industrial boilers and combustors are an important source of CO. Of the more than 1 million tons of CO emitted in 1999 (EPA 1999), the largest source categories by far were biomass-fired boilers and combustors (228,812 tons/year), natural-gas-fueled reciprocating engines (206,647 tons/year), turbines (26,776 tons/year), and boilers (85,665 tons/year).

The diversity of applications in which industrial boilers and combustors are used makes them important sources of four of the six criteria pollutants. After the phased elimination of leaded gasoline from 1975 to 1986, the primary source of lead emission shifted from automobiles to metalworking (smelters) and battery-manufacturing processes, neither of which is considered in this section. Ozone is not directly produced by fossil-fuel combustion, although NO_x emissions and fugitive hydrocarbon emissions from fuel storage and supply components, among other sources, contribute to ozone formation (see Chapter 7). The remaining four criteria pollutants are emitted as a result of the combustion process; different fuels and types of combustion result in different emissions. Various abatement techniques are used to control emissions of these pollutants:

- SO_2 abatement: low-sulfur fuels (coal and oil).
- NO_x abatement: NO_x reduction (primarily SNCR, but also SCR), combustion best practices (such as lean combustion, air staging, flue-gas recirculation, and steam injection), and low-NO_x burners.
- CO abatement: none.
- PM abatement: electrostatic precipitators, fabric filters, cyclones, and wet gas scrubbers.

Repair and replacement activities that are typical for industrial boilers and combustors are likely to be similar in many ways to those for utility boilers:

- Burner inspection and repair: For solid fuels and liquid fuels containing substantial impurities, the fuel-injection process can erode fuel-injector parts over time, degrading burner performance. Periodic inspection and repair are required to monitor and address degraded burner operation.

- Repair or replacement of heat-exchanger tubes: Heat is transferred from the hot-side combustion gases to the cold-side fluid (typically water) in large arrays of heat-exchanger tubes. When fuels high in mineral impurities are burned, deposits condense on the outside of the tubes, reducing the rate of heat transfer and eventually requiring replacement or repair. The thermal and mechanical stresses imposed on the tubes can cause rupture. Periodic inspections are required and can lead to repair of degraded or damaged heat-exchanger tubes.

Petroleum Refining

The domestic petroleum-refining industry consists of 152 facilities (down from 324 in 1981), geographically dispersed across 32 states. Facilities are located in both urban and rural areas; multiple facilities located on the coast of the Gulf of Mexico, along the Delaware River valley border of Pennsylvania and New Jersey, along the Pacific coast of California, northcentral Utah, and northwestern Washington State. Other refineries are along the western Great Lakes and along the East Coast from New York to Virginia. Some average-size inland refineries are in Kansas, Oklahoma, Illinois, Tennessee, Kentucky, and Indiana. Petroleum refineries have a substantial impact on environmental quality of all sorts, not just air quality. For example, of all industries operating in California, petroleum refining is the largest source of hazardous wastes (CalEPA 2004). Of the petroleum refineries designated as major sources, 57% are in nonattainment areas (Abt Associates Inc. 2003). The geographic distribution of refineries means that controlling air emissions from these facilities potentially affects tens of millions of people, both those living and working nearby in nonattainment areas and those downwind in regions that may or may not be classified as nonattainment areas. Table 3-5 presents an inventory of emissions from typical petroleum-refining processes.

Petroleum refining is the process by which crude oil is converted into hydrocarbon products. Refineries range in processing capacity from 1,000 to 545,000 barrels/day (EIA 2003a). Fuels make up about 90% of the output of refineries; the remainder is composed of lubricants and other hydrocarbon-based petrochemical products. Because each refinery constitutes a very large capital investment and because the product lines of refineries vary, refinery configurations vary from one facility to another.

It is illustrative to consider petroleum refining as consisting of a series of chemical reactors, each operating at a different temperature and pressure and handling different hydrocarbon feeds. Supporting the reactors is an array of devices that transport, blend, separate, pressurize, and heat the

TABLE 3-5 National Emissions Inventory of Typical Petroleum-Refining Processes, tons per year

Process (no. facilities with process)	NO_x	PM_{10}	$PM_{2.5}$	CO	SO_2	VOCs	NH_3
Vacuum distillation (34)	24	8	7	45	135	1,763	1
Catalytic cracking (78)	22,946	12,002	9,267	80,008	105,499	6,800	1,286
Fluid coking (13)	43	153	111	4	3,712	484	1
Oil and gas production (25)	226	138	124	194	727	529	78
Miscellaneous petroleum production (34)	2,036	489	398	1,926	7,534	3,588	64
Chemical production (48)	3,960	274	251	2,750	17,748	2,531	35
Mineral production (6)	18	17	10	27	103	146	3
Miscellaneous production (16)	297	1,001	909	171	473	38	12
Miscellaneous petroleum processes (50)	1,012	186	130	1,074	7,251	1,045	148
Internal combustion (64)	15,884	1,267	1,261	6,261	416	3,801	320
External combustion (277)	146,714	16,471	15,586	45,073	134,072	9,250	5,779
Storage and transportation (178)	1,752	108	—	190	2,635	33,585	196
Water and waste treatment (194)	1,253	2,449	2,243	979	6,336	11,239	344
Fugitives (97)	1,224	518	380	1,696	14,804	40,756	49

SOURCE: Abt Associates 2003.

hydrocarbon feeds and catalysts to the needed conditions. References to a specific refining process necessarily encompass ancillary devices, such as pumps and heaters, which contribute substantially to the total emissions attributed to the process. Typical refining processes, in order of decreasing processing volume, are distillation (atmospheric and vacuum), cracking (catalytic and thermal), catalytic hydrotreating, catalytic reforming, and catalytic hydrocracking (see Figure 3-3). However, for any given facility and its instantaneous product mix, any combination of processes may be active, and this results in a variable "emissions fingerprint" for the facility as a

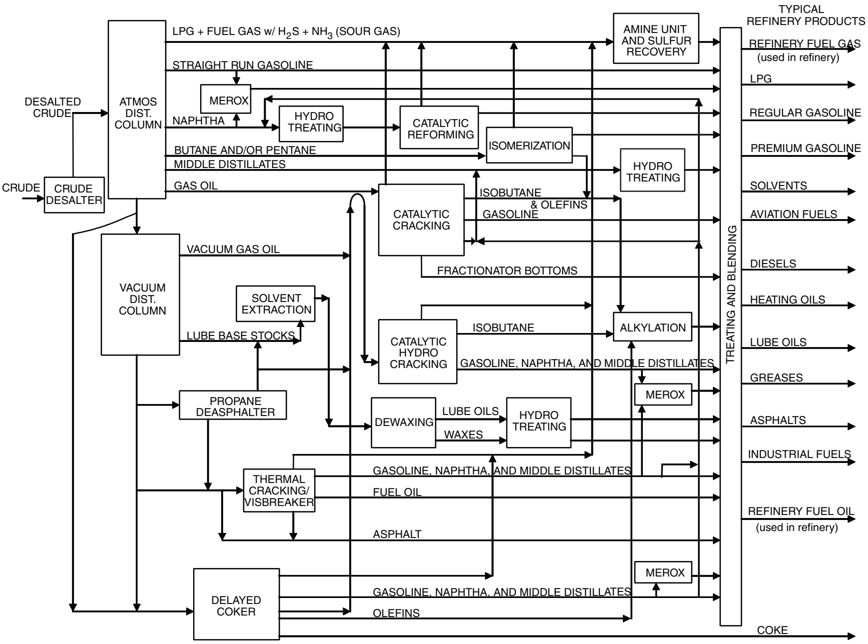

FIGURE 3-3 Simplified process flow diagram for typical petroleum-refinery operation. Overall refining process proceeds from upper left (introduction of raw crude) to final dispensed products along right edge (fuel gases, gasoline, solvents, and so on). Not shown are ancillary devices (such as heaters and pumps) used to alter temperature and pressure of each feed (lines and arrows) as necessary before it enters individual process units (boxes). SOURCE: EPA 1995b, based on Gary and Handwerk 1994.

whole. The national emissions inventory for petroleum refineries presented in Table 3-5 notably aggregates a number of the smaller-volume refining processes under several “miscellaneous” categories.

Also notable in Table 3-5 is the predominance of combustion sources to overall emissions. Many of these combustion sources are associated with the operation of one of the refining processes listed.

To understand the air emissions attributed to each process, a basic understanding of each process is necessary:

Distillation

Distillation is the process of coarsely separating the components of the petroleum feed by boiling-temperature differences. It is achieved by heating the liquid feed to progressively higher temperatures. The different components in the feed volatilize (change from liquid to gas) at different temperatures that are based on molecular weight and mixture composition. Components that volatilize in the same temperature range are then collected, condensed, and sent for further purification. Distillation can take place under atmospheric or reduced-pressure (vacuum) conditions. The latter is used to separate higher-molecular-weight components of the petroleum feed.

Conditioning and Other Miscellaneous Processes

Conditioning and other miscellaneous processes involve manipulating the fluid and chemical characteristics of the petroleum feed to optimize the operation of downstream processes. Hydrotreating removes such impurities as sulfur and nitrogen from hydrocarbon feeds that would poison catalysts used in downstream processes. Hydrotreating also converts olefins (alkenes) to paraffins (alkanes) to prevent the formation of gums in fuels. Hydrotreating involves making the petroleum feed react with hydrogen under high pressure in the presence of a catalyst. Isomerization involves rearranging molecules (typically alkanes) without altering their molecular weight or composition to obtain higher-value isomer species. The process takes place in the presence of a catalyst. In contrast, catalytic reforming converts low-value species (such as naphthas) into high-value species of similar but not necessarily identical molecular weight (such as benzene). Catalytic reforming also takes place in the presence of a catalyst. Dewaxing is a process that removes waxy contaminants (paraffins) from lubricating oils produced in a refining process. The dewaxing process can be either catalytic (paraffins in the lubricant are broken down in reactions over a catalyst) or filtration (paraffins are condensed and removed from the lubricant).

Catalytic Cracking

Catalytic cracking involves breaking down larger hydrocarbon molecules and reforming the fragments into smaller hydrocarbon molecules. It occurs at high temperatures and involves vaporizing the hydrocarbon feed and introducing a granulated or powdered catalyst. In addition to the ancillary processes associated with catalytic cracking that are needed to pressurize and heat the reactants and collect the lower-molecular-weight products, there are supporting processes to recover, regenerate, and reheat the granulated or powdered catalyst material. Regeneration of the catalyst under reducing conditions is a primary source of CO.

Sulfur Recovery

The sulfur-recovery process, also referred to as gas "sweetening," involves removing primarily hydrogen sulfide (H_2S) from process gases for conversion to elemental sulfur and eventual resale. The predominant sulfur-recovery method is a modified Claus process in which the gaseous H_2S stream is partially oxidized to SO_2. The mixture of SO_2 and H_2S then reacts over a catalyst to produce elemental sulfur. Because the modified Claus process is 94-97% efficient, additional steps are usually required to extract the remaining sulfur compounds in the "tail gas." If the remaining sulfur in the tail gas is predominantly H_2S, the tail-gas stream can be directed to a thermal oxidizer to convert H_2S to SO_2 and then be subjected to wet or caustic scrubbing. Alternatively, the Beaven process adsorbs H_2S in a quinone solution, producing hydroquinone and elemental sulfur. This mixture is then centrifuged to remove the sulfur and oxidized to convert the hydroquinone back to quinone, which is then recycled in the process. If a variety of sulfur compounds exist in the modified Claus tail gas (such as SO_2, carbonyl sulfide, and carbon disulfide), a Shell Claus off-gas treating (SCOT) process is used to catalytically reduce these compounds to H_2S (with cobalt-molybdenum as a catalyst), which is then adsorbed in a regenerable diisopropanolamine solution.

Combustion

Boilers, incinerators, furnaces, and steam generators supply steam and electric power to drive machinery and provide heat for various refining processes. Fuels fed into these devices include coal, fuel oil, and natural gas. Flares and incinerators oxidize compounds within a waste or off-gas stream. Air emissions from the devices are typical of those of hydrocarbon-fueled combustion devices.

Fugitive Emissions

Fugitive emissions originate throughout the refining process as a result of leaks from seals associated with fittings connecting pipes, tanks, and process devices. Fugitive emissions also originate from the loading and unloading of materials (such as PM generated and released during coke handling and VOCs released during charging of tanks and loading of barges), as well as from wastewater-treatment processes (such as aeration and holding ponds).

Air Emissions from Petroleum Refining and Their Control

Air emissions from petroleum refining largely consist of SO_2, NO_x, PM, VOCs, and CO. The abatement technologies cited for each pollutant reflect the technologies catalogued in a review of EPA's RACT-BACT-LAER clearinghouse (more than 100 facilities and more than 350 processes reviewed, listed under "petroleum-refining processes").

SO_2 is generated as a consequence of sulfur removal during refining. Other processes, such catalyst regeneration, as well as burning or flaring of selected hydrocarbon streams, are also potential sources of SO_2. Typical control approaches include reduction of sulfur in the fuel stream or scrubbing of SO_2 from the combustion product gases (e.g., wet gas, caustic, Beaven, SCOT, Welman-Lord processes), as well as leak detection and prevention.

NO_x emissions overwhelmingly originate from combustion processes used for heating and therefore are subject to the same NO_x-formation mechanisms described previously for coal-fired electricity-generating facilities. As a result, nearly all of the same NO_x abatement and control technologies used for coal-fired electricity-generating facilities are also used for petroleum refining: SCR, SNCR, and combustion modifications (e.g., lean combustion, air staging, flue-gas recirculation, steam injection, low-NO_x burners) as well as daily or annual restrictions on operation.

Fugitive releases of VOCs occur from a variety of refining processes, including distillation, catalytic cracking and re-forming, isomerization, waste treatment, and materials loading. VOC abatement involves flares and incineration, leak detection and prevention, and vapor recovery.

The principal source of CO is the catalyst regeneration process and the principle abatement approach is a CO boiler or oxidizer.

Sources of PM include the catalytic cracker, catalyst regeneration processes, various combustion processes, and materials handling. Conventional PM control devices are used for abatement and control, including electrostatic precipitators, cyclones, baghouses, and wet gas scrubbers for PM-laden process streams. To reduce fugitive PM emissions, covered conveyors and telescoping chutes can be used as well as implementing water misting during solids loading and unloading.

The equipment replacement provision (ERP) would have exempted changes from triggering NSR activities that are considered "routine maintenance and repair" (see Chapter 2). If some type of ERP were to be included as part of NSR revision, any assessment of the effects of such revision would have to consider the types of repair and replacement activities typical of petroleum refineries. Table E-2 in Appendix E presents the aggregated responses to a National Petrochemical and Refiners Association member survey initiated in response to an information request from the committee.

Pulp and Paper

The pulp and paper industry is a multifaceted industry, encompassing various facilities that manufacture paper and paperboard products, including linerboard, office paper, paper bags, paper towels, tissue, newsprint, and napkins. Because of the variety of final products, the mills that exist in the United States can be very different, and the process flow diagrams can vary. Typically, the manufacture of paper and paperboard products involves chemical pulping, mechanical pulping, or combined chemical and mechanical pulping. However, about 80% of the facilities that exist in the United States are mills that manufacture paper products with the Kraft process (Springer 2000). This section on the pulp and paper industry focuses specifically on Kraft mills because of their prevalence in the United States and the numerous air-pollution concerns associated with the chemical-recovery processes of Kraft mills.

A basic flow diagram of a mill operating with the Kraft process is depicted in Figure 3-4. In addition to the major components in Figure 3-4, each mill also has a separate boiler for producing steam and power. All the subprocesses depicted in Figure 3-4 and the power boiler are critical to the overall production rate, and each has components that require repair or replacement to ensure proper operation. Thus, each section of a typical Kraft mill is potentially affected by the NSR changes.

The process of generating paper in a Kraft mill involves four primary processes: preparing and digesting the raw materials, processing the pulp, drying and preparing the product, and chemical recovery.

Preparing and Digesting Raw Materials

Hardwoods and softwoods are used in paper mills. The final product of the mill dictates the type of material used. However, regardless of the nature of the wood, the primary step in a Kraft process involves debarking the wood logs (with a mechanical procedure) and reducing the raw materials to chips. The chips are size segregated, and those deemed "too small" are transferred to the power boilers for use as fuel. Larger chips are mechanically processed further to achieve optimal size and then fed into the digesters.

Digesters in a Kraft mill are either batch or continuous-flow reactors that are used to convert raw wood chips to pulp. As noted in Figure 3-4, wood chips of optimal size are mixed with a white liquor that consists of sodium sulfide (Na_2S), sodium hydroxide (NaOH), and water. At high temperatures and pressures, the white liquor helps to convert the wood chips to a soluble phase containing the lignin and an insoluble phase (the brown

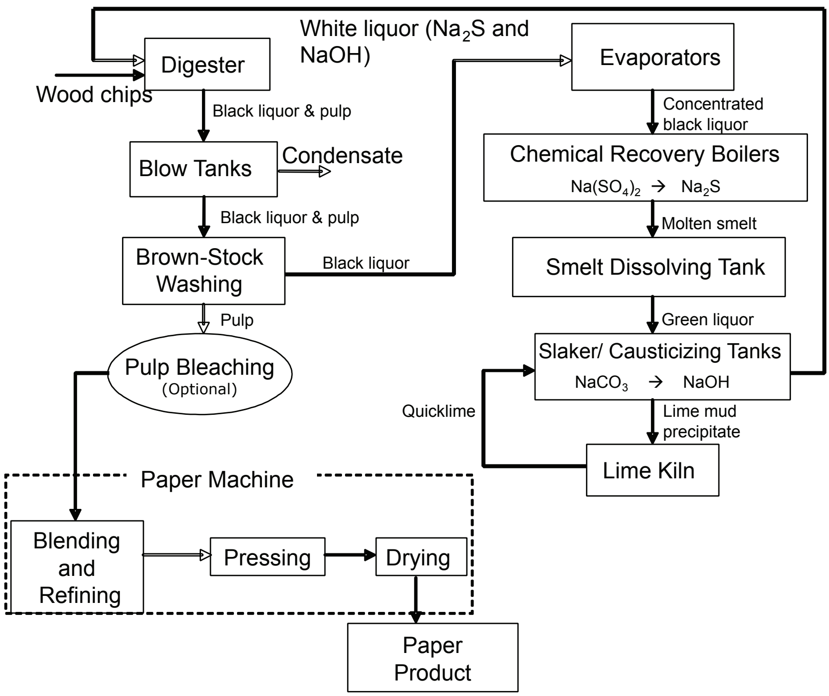

FIGURE 3-4 Schematic of major processes in Kraft mill. Note that the "Paper Machine" consists of several steps, which may vary depending on the final desired product. The items shown are examples of steps that may be included.

pulp) that is further processed into paper. The soluble and insoluble phases are separated in the blow tanks.

Paper products may also contain recycled paper that is brought into the mill. Once received at the mill, wastepaper bales are conveyed to a pulper where the secondary fiber is dispersed into a wet-pulp slurry. In the pulper, inks and coating materials are separated from the fiber. Strings, wires, plastics, and other impurities that may exist in the wastepaper are removed.

Processing the Pulp

The pulp that emanates from the blow tanks is subjected to additional processing to remove spent digesting liquids (black liquor), improve the quality of the pulp, and depending on the final product, bleach the pulp. The brownstock washers are used to separate the digestion liquids from the pulp material. The diluted black liquor that leaves the brownstock washers is collected for processing and recovery. Washed pulp (brownstock) is also passed through screens to remove excessively large (partially undigested) or small pieces of the pulp. A proper pulp size is needed to ensure the strength and quality of the final product.

Some Kraft mills also use a bleaching process to convert the brown pulp to a white (bleached) pulp. That bleaching process involves the use of chemicals such as chlorine dioxide, hydrogen peroxide, and ozone to remove residual lignin from the pulp and results in a brightening or bleaching of the digested raw material. Pulp is introduced into a bleaching tower, bleached, and then washed to remove excess bleaching liquid.

Papermaking

The washed (and perhaps bleached) pulp is processed into a final product through a series of processes that vary based on the final product desired. The processes may involve blending hard and soft woods but always include discharge of a pulp slurry onto a forming fabric, dewatering, and drying. Blending of softwoods and hardwoods changes the ultimate strength and characteristics (such as softness) of the final product. Different wood types are processed in the digesters separately to ensure that proper digestion times and recovery techniques are used. (For example, softwoods contain high concentrations of terpenes; after the digestion process, gases emanating from the digester and blow tanks used for softwood processing may be condensed and recovered to form turpentine.) To achieve the desired final-product characteristics, softwood pulp and hardwood pulp may be blended. Not all papermaking processes employ a blending technique. Once the appropriate pulp characteristics are achieved, the pulp is sprayed onto large pressing and drying rollers where the paper product is formed, as indicated previously. The paper products that are formed and dried are ultimately converted to customer-usable products such as boxes, bags, tissue, etc.

Chemical Recovery

A critical component of a Kraft mill is the chemical recovery process. The black liquor generated in the digester is captured in the blow tanks and washer sections of a typical mill and then concentrated in evaporators and burned in a recovery boiler to recover Na_2S. The molten smelt that is generated reacts further with lime to ultimately recover NaOH. The recovered Na_2S and NaOH form the basis of the white liquor that is fed into the digesters as wood chips are processed.

Typical Emissions and Control Equipment

The primary emissions from a Kraft mill are VOCs, SO_2, NO_x, CO, total reduced sulfur (TRS), and PM. The emission rates of the pollutants depends on the wood products used (softwood versus hardwood) and on the final product of the mill (Davis 2000; Someshwar 2003). The National Council for Air and Stream Improvement and EPA have conducted studies to determine the typical emissions from specific mill processes (Someshwar 2003; NCASI 2004). Table 3-6 provides data on the types of compounds emanating from the major sections of a typical Kraft mill and the typical air-pollution-control devices that are used to reduce emissions (Davis 2000; Springer 2000; Someshwar 2003; NCASI 2004; Witkowski and Wyles 2004). The composition of emissions from the power boilers depends on the type of fuel used. Typical fuels and the percentage of mills using the specified fuel in steam-generating power boilers are as follows: natural gas, about 33%; wood, about 33%; coal, about 26%; and oil and miscellaneous fuels, about 8% (NCASI 2004). Although the use of waste bark may be an efficient use of resources, the combustion of bark typically generates excessively high levels of CO compared with the combustion of other fuels in a typical steam-generating power boiler (NCASI 2004). However, the use of

TABLE 3-6 Typical Air-Pollutant Compositions and Emission-Control Equipment Used in Each Subprocess in Kraft Mills

Subprocess	Pollutants	Typical Emission Control[a]
Digester	VOCs, sulfur compounds	Combustion
Blow tanks	VOCs, sulfur compounds	Combustion
Brownstock washing	VOCs, sulfur compounds	Combustion
Bleaching	Halogenated compounds (particularly chlorine dioxide and chloroform), CO, methanol	Scrubber
Chemical-recovery boilers	PM, NO_x, sulfur compounds, CO, VOCs	ESP, SNCR
Smelt-dissolving tanks	PM, sulfur compounds, VOCs, ammonia	Scrubbers
Slaker and causticizing tanks	PM	Scrubbers
Lime kiln	PM, sulfur compounds, NO_x, CO, VOCs	Scrubbers or ESP
Drying	VOCs, sulfur compounds	Combustion

[a]The control equipment listed in not necessarily for the control of all the pollutants that are listed for each subprocess. For example, an ESP will control only PM emissions.

SOURCE: Adapted from Witkowski and Wyles 2004.

waste bark as a fuel may also be beneficial to air quality, because NO_x and SO_2 concentrations are reduced.

Mill Repair and Replacement Activities

Numerous repair and replacement activities are periodically undertaken to ensure safe and optimal mill performance. For existing Kraft mills, these types of activities have the potential to trigger NSR, and any effort to assess the effect of operational changes in the NSR program on Kraft mills depends on the nature of the activities. Table E-3 in Appendix E lists repair and replacement and other activities peculiar to Kraft mills that are periodically undertaken. The quality and variety of the fuel types used in the pulp and paper industry may result in repair or replacement activities for facility components that are different from those in industrial sectors that rely on one fuel type.

Time Frames for Industrial Production and Process Change

The previous sections have highlighted some key industries and the process technologies that are used to create products. This section briefly addresses the notion that there is a temporal aspect of industrial production. The temporal aspect has several specific considerations. One is that a given product mix must be produced to meet demand, typically involving a characteristic load profile. Another is that the product mix may change to meet market needs. The ability to store an output allows for scheduling the operation of the plant so as not to be closely coupled to the demand cycle. This, in turn, may have implications for steady-state operations, which is an important consideration for control of emissions.

For electric-power generation, electricity is produced at the same time that it is consumed. It is impractical to store electricity for later use, so the total power-generation level must change as the demand for electricity changes. Some power plants, particularly the larger coal-fired and nuclear plants, are often run in a "baseload" mode, which means roughly constant output. Other plants, which typically have higher marginal fuel costs, such as natural-gas-fired systems, may operate in "intermediate" or "peaking" modes. An intermediate-load plant may ramp up and down once a day to capture substantial increases in the daytime electricity demand over overnight demand. A peaking plant may operate for only a few hours per day to accommodate specific periods of highest electricity demand. The overall average capacity factor of a baseload plant can be about 80%, versus 50% or less for an intermediate-load plant and perhaps only 15% for a peaking-load plant.

In petroleum refining, where it is possible to store the product (in tanks), it is more economical to size the plants and operate them to achieve roughly steady-state production at high-use factors. Thus, in contrast with electric-power generation, refineries typically operate at roughly constant load factors. However, the product mix changes over the course of the year. For example, gasoline formulations typically change to a less volatile mix in the summer to reduce evaporative emissions of photochemically active ozone precursors. The specifics of the operations at the refineries may change over the course of a year because of changes in product mix. Similarly, in other industries, such as automotive and pharmaceutical, there may be periodic "retooling" or transitioning to other products or product mixes. Those changes potentially can require modifications to existing facilities or other changes that might affect energy use or efficiency.

TECHNOLOGICAL CHANGE

The stringency and form of environmental regulation can influence the nature and speed of technological change for pollution-control equipment and have important implications for the cost and performance characteristics of that equipment. Technological advances can lead to lower costs of installing pollution-control devices, lower costs of operating the devices, improved emission-reduction performance, or some combination of those. Understanding the relationship between regulation and technological change is important for accurate assessment of the costs and, in some cases, the benefits of environmental regulation, including the changes in NSR rules being considered in this report.

Regulatory stringency and applicability have a direct relationship to the size of the potential market for a particular control technology and the incentive of a developer to improve it. Greater certainty about future regulatory requirements also provides for a more accurate assessment of the potential market for a particular technology and may increase incentives for improving it. The potential for being designated NSPS, BACT, or LAER, in theory, could provide an incentive for technology developers to devise a better technology for reducing or even preventing emissions, but there are few empirical studies of the effects of regulations on new-technology development. NESCAUM (2000) provides some information regarding the adoption of technologies for control of NO_x and SO_2 emissions along with regulatory context. The form of environmental regulations—whether technology standards, emission-rate standards, or cap-and-trade programs—will also affect incentives for different forms of innovation. In particular, emission cap-and-trade regulations impose an opportunity cost in the form of the price of an emission allowance on every ton of pollutant emitted and thereby potentially create a stronger incentive to improve emission-control efficiencies of particular technologies than would exist with either technology standards or emission-rate standards (Keohane 2002). Emission cap-and-trade programs also lower costs by reducing the need for control-equipment redundancy to meet a national or regional emissions target. If a facility is required to control emissions whenever the facility is running, redundant pollution controls would be necessary. However, with a cap-and-trade program, the facility operator can continue to operate even when the pollution-control equipment is not operating and cover the additional emissions by purchasing or retiring more allowances.

To illustrate the relationship between environmental regulation and the development of emission-control technologies, we consider two examples of such technologies: FGD technology used to reduce emissions of SO_2 and SCR technology used to reduce NO_x emissions from fossil-fuel-fired boilers used to generate electricity. Both FGD and SCR are technology options that are included in the modeling analysis of the electricity sector as reported in Chapter 6.

Flue-Gas Desulfurization

FGD technology is of particular interest because it must be installed for compliance with NSPS for SO_2-emission reduction at new pulverized-coal electricity-generating units. The recent settlements of EPA NSR enforcement cases against several electricity-generating facilities (see Chapter 2) included agreements to install FGD scrubbers at one or more coal-fired units. FGD units were also an important part of electricity-generating-facility compliance strategies with the SO_2 cap-and-trade provisions of Title IV of the 1990 CAA amendments. Sixteen electricity-generating facilities installed retrofit FGD units in at least one of their existing coal-fired generators to comply with Phase I of Title IV (Swift 2001). About eight scrubbers were installed after stricter caps were put into place under Phase II of the program, which took effect in 2000 (Burtraw and Palmer 2004).

Studies of the effect of NSPS and Title IV on innovation in scrubber technology suggest that both forms of regulation helped to spur technological advances, but of different types. Taylor et al. (2003) found that patents relevant to SO_2-control technology grew dramatically in the early 1970s and remained high through the middle 1990s relative to earlier periods. Popp (2003) found that SO_2-removal patent counts peaked in the early 1980s at substantially above post-1990 levels. He suggested that that pattern indicates that stricter NSPS rules issued in the late 1970s contributed to increased patenting in the early 1980s. The later decline in patenting activity could be due to a combination of factors, including lower-than-expected SO_2-allowance prices, the drop in construction of new coal-fired generators, the maturity of the FGD technology, and a declining propensity to patent in general.

Several authors find that the move toward a more flexible cap-and-trade approach to SO_2 regulation contributed to innovation. Burtraw (1996, 2000) found that the flexibility associated with permit trading allowed generators to make changes in institutional behavior that helped to lower costs and, by creating a form of competition with scrubbing, helped to provide incentives to reduce scrubbing costs. Popp (2003) found that although capital and operating costs of scrubbers declined during the period since first implementation of NSPS, the move to cap-and-trade regulation for SO_2 in the late 1990s was accompanied by an improvement in the SO_2-removal efficiency of FGD units. That improvement is seen as a direct result of the stronger incentive to continually reduce emissions associated with a need to hold SO_2 allowances to cover all emissions. Keohane (2002) also found that FGD equipment costs did not decline during Phase I of Title IV but that the operating efficiency of scrubbers did increase and brought about large declines in operating costs per ton of SO_2 removed. Recent vintages of FGD units reduce potential stack emissions of SO_2 by 95% or more, whereas the median emission reduction before the revised NSPS for SO_2 in the late 1970s was closer to 80% (Popp 2003; Taylor et al. 2003). Today's systems are also much more reliable than were the FGD systems installed in the 1980s, and the increased reliability contributes to higher total SO_2 removal (Taylor et al. 2003).

Improvements in reliability and in the removal efficiency of FGDs are linked to some extent. As noted by de Nevers (2000), the electricity-generating industry endured problems associated with the early adoption of systems, such as limestone scrubbers, in the 1970s and early 1980s. Examples of problems encountered included higher-than-anticipated corrosion of metals; deposits of solids, and scaling and plugging in the FGD system itself; entrainment of slurry droplets and downstream deposition of solids; underuse of reagent; and problems with the separation of water from the waste products. Solutions to those problems have included better control of pH in the slurry, better control of the composition of the slurry to avoid scaling and plugging problems, improved design of such key components as entrainment separators, and increased slurry holding times and oxidation.

Learning by doing also has helped to bring down the costs of operating FGD units. Taylor (2001) showed that the operating costs of FGD units have fallen by 17% for every doubling of installed capacity. Capital costs of a wet limestone scrubber designed to reduce emissions of 3.5% sulfur coal by 90% at a 500-MW unit have fallen by roughly 50% over 20 years, and the bulk of the decline occurred before the beginning of the cap-and-trade program (Taylor et al. 2003, Figure 6).

Selective Catalytic Reduction

SCR technology is of interest because it is an effective means of reducing NO_x emissions from boilers at electricity-generating facilities; it has the potential to reduce emissions by 70-90%. SCR generally is assumed to be necessary to meet NSPS requirements for NO_x reductions at new pulverized-coal facilities. It is also the technology typically selected to control NO_x in settlements of NSR-enforcement cases brought against large electricity producers by EPA in recent years.

SCR is one of many ways to control NO_x emissions, and it is a relatively capital-intensive and expensive method compared with other approaches (Swift 2001) that have proved sufficient to achieve compliance with recent NO_x regulations. Before the 1990 CAA amendments, many existing coal-fired generators faced no restrictions on emissions of NO_x. Title IV of the 1990 CAA amendments imposed an annual average emission-rate cap on NO_x emissions for coal-fired generators in the United States. The emission-rate limit was based on the use of low-NO_x burners, and the standard varied by boiler type (Swift 2001). Most units complied with the regulation by installing low-NO_x burners, although flexibility provisions in the law, such as emission-rate averaging across units at a plant, encouraged firms to reduce emissions through other means, such as changing air-fuel mixtures and adjusting boiler temperatures to reduce NO_x emissions, before investing in control technology (Swift 2001). The linking of the standards to the degree of reduction achievable with low-NO_x burner technology provided limited incentive for U.S. coal-fired generators to adopt the more expensive SCR technology. However, in several states, such as California, SCR was applied starting in the 1980s on gas-turbine combined-cycle facilities.

Demand for SCR to reduce NO_x emissions was expected to grow somewhat when the Ozone Transport Commission (OTC) program for capping summertime NO_x emissions from electricity generators in nine northeastern states took effect in 1999. The cap began in Phase II of the OTC program, which ran from 1999 through 2002, mandating a 55% reduction below 1990 levels in summertime NO_x emissions from affected sources. Despite the large reductions sought, most of the regulated units were able to achieve a large fraction of the required reductions in NO_x emissions through operational changes, so the role for SCR was much smaller than expected (Swift 2001). Beginning in summer 2003, the cap was tightened to roughly 70% below the 1990 level (Burtraw and Evans 2004). The geographically more expansive multistate NO_x caps under EPA's NO_x SIP call, which covers 19 states and the District of Columbia and took effect in summer 2004, greatly increased installations of SCR technology. Coal-fired power plants in a number of states also have retrofitted combustion and postcombustion NO_x controls (for example, low-NO_x burners and SCR) in response to SIP requirements for attaining National Ambient Air Quality Standards. For example, the first retrofit of SCR to a coal-fired power plant occurred in 1995 (NESCAUM 2000).

The United States was a relatively late adopter of SCR. In Japan, it was used as early as the late 1970s but at much lower removal rates than are common today, typically at a rate of 60%. The lower removal rates meant that there was less of an issue with ammonia slip, because use of ammonia is more complete under these conditions. Ammonia slip refers to unreacted ammonia that leaves the SCR system and is vented to the atmosphere with the stack gases. German coal-fired boilers adopted SCR in the late 1980s and early 1990s in combination with environmental regulations. During the 1980s, improvements in catalyst formulation, as well as injection grids and control systems enabled achievement of 80-90% removal efficiencies with less ammonia slip for a wider variety of flue-gas compositions.

One barrier to adoption of SCR in the United States during the 1980s, in addition to high costs and relatively low regulatory stringency, was the perception that SCR could not be used in U.S. coal plants because the alkali content of U.S. coal was higher than that of coal used in Japan (or Germany) and that the difference could be a potential cause of catalyst plugging or poisoning. However, experience has shown that, with appropriate catalyst formulation, different coal chemistry is not a problem. Other potential problems with the application of SCR, such as ammonium salt deposition on downstream equipment, are apparently reduced or eliminated by controlling ammonia slip and by selecting appropriate materials and surfaces for such equipment (for example, an air preheater).

Current work by Taylor (2004) finds that SCR emission-removal efficiencies have improved dramatically coincidentally with the spread of regulations requiring or spurring their use—from Japan in the late 1970s to early 1980s to Germany in the late 1980s to early 1990s and then to the United States more recently. Increased SCR use in the United States has come about only recently, largely in response to the regional summertime NO_x-emission cap-and-trade programs in the northeastern states and to NSR requirements. Currently, removal efficiencies of 90% and higher are feasible, and typically 90% removal is guaranteed by vendors (Culligan and Krolewski 2001). Operating costs of SCR units have also declined by 50% in 10 years (Taylor 2004).

New Source Review Modifications and Incentives for Technological Change

Several economic researchers have asked whether NSR regulations inhibit technological change. Anecdotal evidence and a small amount of empirical evidence, discussed in Chapter 5, suggest that differentiated regulation of new sources slows capital turnover and that differentiated regulation of modified sources reduces investment in modifications and upgrades at existing plants. To the extent that the technological modifications would have promoted new technologies, the evidence of reduced investment at existing plants could be consistent with dampened diffusion of new technology and reduced technological change more broadly. However, no empirical studies have explored the relationship directly (Jaffe et al. 2003). Not addressed here is the issue of the implications of tighter controls on new sources versus keeping older sources on line longer.

The dearth of literature on NSR and technological change and the lack of direct evidence make it difficult to offer much in the way of informed judgment about how the recent NSR rule changes are likely to affect innovation. To the extent that regulation reduces the applicability of BACT and LAER to existing sources, it could reduce demand for pollution-control retrofits and thereby reduce innovation by technology developers. However, if the fact that NSR applies only when major modifications actually take place limited investment activity in the first place, then this effect is likely to be small.

Most of the NSR revisions—such as changes in methods of estimating emission effects and baseline emissions, and plantwide applicability limitations—limit the possibility that a particular investment or expenditure at an existing facility will trigger NSR. Those favoring the NSR rule changes have asserted that concerns over triggering NSR reduced investments at existing plants and reduced markets for new technologies (see Box 3-1). They also have asserted that limiting its applicability could increase the adoption of new technologies, which in turn could spur technological innovation. Whether that hypothesized effect would occur remains an open question.

SUMMARY

The key conclusions of this chapter are as follows:

- Permits for modifications involve only 1-2% of total emissions for most pollutants in either the manufacturing or electricity-generating sector (including facilities that did not receive an NSR permit in the period 1997-2002). However, NSR permitting activity pertaining to modifications was substantial when considering only those facilities that received an NSR permit during the period considered. On the basis of preliminary data, which are subject to various limitations, permits for modifications account for 25-48% of the reported total amount of permitted emissions, depending on the pollutant, among all facilities that are reported to have received an NSR permit.

BOX 3-1
Example of an Emerging Technology: IGCC

Integrated gasification combined cycle (IGCC) is an example of an emerging technology. The IGCC features the gasification, rather than combustion, of fuels. For example, coal (or a wide variety of other fuels, including waste fuels) is partially combusted by using an oxidant (typically 95% pure oxygen from a dedicated air-separation plant), and steam or water is added. The partial combustion of the fuel supplies thermal energy for endothermic gasification reactions that lead to the formation of a synthesis gas ("syngas") containing CO, hydrogen, and other substances. The bulk of noncombustible material in the fuel is removed via the bottom of the gasifier as a vitrified "slag" that typically is less leachable than the bottom ash of a conventional furnace. The syngas goes through gas cooling, scrubbing, and acid-gas separation to remove particles, H_2S, and carbonyl sulfide (COS). The sulfur is recovered in elemental, solid form and can be used as a byproduct. The syngas can be used as a fuel in a gas-turbine combined cycle to generate power. Alternatively, it can be used as a feedstock for the production of chemicals, such as hydrogen, ammonia, and methanol. Gasification can be the cornerstone of a "polygeneration" system or "coal refinery" that creates a mix of multiple products. For power-generation applications, NO_x emission can be prevented or minimized via saturation of the syngas with moisture or injection of nitrogen from the air-separation plant. However, postcombustion SCR can be used for additional NO_x control if needed. IGCC systems are generally more efficient than combustion-based systems, use less water, have lower air-pollutant emissions, and have greater fuel flexibility. Even if advanced supercritical combustion-based plants attain comparable efficiency, IGCC plants could still offer advantages of greater fuel flexibility, coproduction of multiple products, and the potential for less-expensive carbon sequestration. Although IGCC technology has been shown to be technically feasible in several large-scale demonstration plants, it has not yet been cost-competitive in the United States. However, American Electric Power has recently announced its intentions to construct the first commercial IGCC plant in the United States some time in the next 5-6 years.

- NSR permits for modifications have been issued for a wide variety of emission-source categories but primarily, following whether measured by number of permits or by amounts of permitted emissions, in electricity-generating facilities; stone, clay, and glass products; paper and allied products; chemicals and allied products; and food and kindred products.

- Although the industries are diverse, their emission processes are often similar. For example, many industries use common unit operations, such as industrial furnaces to generate steam for process use, whereas others use combustion sources, such as tunnel or rotary kilns.
- There is substantial variation among states regarding the implementation status of the NSR revisions and the existence of a minor-construction permitting program that might cover modifications that are not covered under NSR. There is limited experience with NSR revisions where the programs have been implemented. Furthermore, there appears to be reluctance by some states and firms to conduct permitting, given the current uncertainty about litigation over the revisions.
- There is a lack of systematic and consistent reporting of NSR permits by states. However, some states appear to be adopting a common framework for electronic management of permits.
- A review of common repair and replacement practices for selected types of process facilities showed that such activities can vary considerably in frequency and cost.[7] Likewise, for a given emission source, such as a boiler at an electricity-generating plant, the wide array of pollution-prevention and -control options can vary in effectiveness and cost.
- Emission sources, pollution-prevention techniques, and pollution-control technology are expected to change, and regulations like those considered here can be part of the motivating factors for such change. However, the effects of regulations can vary greatly, depending on the specifics of programs.

[7]The committee takes no position on whether these repair and replacement activities are "routine" within the meaning of EPA's prerevision or revised NSR regulations.

4

Analytic Framework for Assessing Effects of New Source Review Rule Changes

INTRODUCTION

In this chapter, we review the various methods that could be used to assess the effects of the recent New Source Review (NSR) rule changes. They include econometric and statistical models, process-engineering models of particular facilities, and simulation models for the electric-power sector. Previous U.S. Environmental Protection Agency (EPA) studies using an industry-sector model are briefly summarized, and a preliminary statistical analysis of relative emission changes in two periods, 1987-1989 and 1996-1998, is provided. This chapter provides a basis for discussions, conclusions, and recommendations presented in the remainder of the report.

A number of analytic methods could, in principle, be used to assess the effects of the EPA's recent changes in the NSR rules. They involve economic models that describe the response to changes by individual firms or facilities; industrial sectors, such as the oil and petroleum sector and the electricity-generating sector; or multiple sectors or the entire economy. Formal models are based on a set of underlying economic assumptions, such as profit maximization and market clearing of all surpluses and shortages. In addition, statistical evaluations of economic activity and emissions under different regulatory conditions can be used to estimate how different levels of NSR enforcement may have altered emissions in the past. Once changes in emissions are estimated, a full assessment of effects includes an evaluation of how the emission changes might affect air quality and human exposures and of the resulting health consequences of those exposures.

Different indicators can be used to assess magnitudes and trends in pollution prevention and control, energy efficiency, emissions, air quality, and health effects (e.g., NRC 1999; Esty 2001; HEI Accountability Workgroup 2003; Hayward 2004). Table 4-1 lists possible indicators for each. Many of the indicators change or vary from one space or plant to another, and some

TABLE 4-1 Possible Indicators for Assessing Outcomes of Interest

Outcome	Possible Indicators to Assess Outcome
Pollution control	• Innovation in new technologies –Expenditures for research and development –Inventions and patents • Implementation of new technologies—adoption by industries • Improvements in use ("learning by doing")—performance histories for selected technologies
Pollution prevention (source reduction)	• Innovation, implementation, and improvements in industrial processes to be less polluting –Expenditures for research and development –Adoption by industries –Performance histories of selected technologies –Trends in emissions generated per unit of product produced • Life-cycle material-use effects, considering economywide effects through supply chain and product delivery, use, reuse, and disposal –Number of products introduced into commerce with reduced hazardous properties –Substitution of materials with less-polluting substances
Energy efficiency	• Innovation, implementation, and improvement in use of new technologies that enable energy efficiency in electricity generation and industrial processes • Energy efficiency of operating units and plants • Industry sectorwide energy use • Life-cycle energy-use effects, considering economywide effects through supply chain and product delivery, use, reuse, and disposal
Emissions	• Trends in emissions for individual units, plants, industries, states, regions, and nation as a whole • Relationships between emissions and unit and plant operating costs and use • Life-cycle emission effects
Air quality	• Ambient concentrations of relevant emitted primary pollutants and pollutants formed in atmosphere over various spatial and temporal scales
Health effects	• Human exposure and dose • Mortality and disease –Population incidence –Incidence in particular subpopulations (regional and socioeconomic) –Risks to highly exposed people

degree of averaging or smoothing may need to be done before the data can be analyzed. In many cases, data from a single comprehensive source (or even distributed among many sources) are not available, and incomplete data would be used for drawing inferences. Furthermore, the indicators in Table 4-1 include factors that are quantitative and directly indicative of a targeted outcome—such as emissions from individual plants, industries, and states—but others that are more qualitative and difficult to measure, such as the rate of innovation in pollution-prevention and -control technologies.

Many of the outcomes and indicators in Table 4-1 are affected by factors beyond the realm of the NSR rules (or even pollution-control laws in general)—such as economic conditions, government investment in R&D, fuel supplies and prices, and meteorologic conditions—and these factors and data should be considered in analyses that attempt to assess the likely effects of NSR rule changes on the outcomes of interest. Any assessment involves (explicitly or implicitly) two estimates: an estimate of what would have happened if the rule changes had not occurred and an estimate of what will happen with the rule changes. Both are subject to substantial uncertainty, and it is necessary to consider a variety of possible scenarios for the economic and environmental assumptions that are being applied.

Table 4-2 illustrates some of the key uncertainties that limit the ability to identify and assess likely outcomes associated with the revised NSR rules. Key uncertainties exist in technological factors, economic conditions, and future regulatory and judicial outcomes regarding the NSR rules. There are also substantial uncertainties in the operating and emissions characteristics of existing facilities, air quality, and patterns of exposure and health effects that might result from the NSR changes.

Technological factors that could affect NSR include changes in the capabilities and costs of new production facilities as compared with the costs and effectiveness of replacement equipment and routine maintenance and repair, and the cost and effectiveness of new air-pollution-control technologies. Rapid evolution of new technologies would encourage more new facilities, and slower technological change will lead to more ongoing maintenance, repairs, and equipment replacements. More effective, less costly pollution-control technologies would encourage increased adoption by industry and result in lower overall emissions and could lead to greater differences between existing facilities that undergo NSR versus those that do not. In particular, facilities subject to NSR under the scenario of rapid innovation would have access to more-effective emission-control technologies than would be the case under a scenario of less-technological innovation.

Economic factors that could influence the effects of the NSR rule changes include uncertainty in (1) the general level of economic growth, (2) future demand for a particular industry's products, and (3) future prices for fuels and other production inputs. Greater economic growth and demand would

TABLE 4-2 Key Uncertainties in Assessing Effects of NSR Rules Changes

Domain	Uncertain Element	Implications for Assessing NSR Effects
Technological advancement	Relative effectiveness of new facilities vs replacement and renovation of equipment	Rapid evolution of technology for an industry will lead to more new facilities with cleaner technologies, while slower technological change would encourage prolonged life for existing facilities.
	Cost and effectiveness of new pollution-prevention and -control technologies	More effective, less costly pollution-prevention and -control technologies would encourage increased adoption by industry but would also lead to greater differences in emissions between facilities that are subject to NSR and those that are not. However, some emission reductions resulting from investments in plant efficiency that might be discouraged by stricter NSR enforcement could also be achieved.
Economic	General level of economic growth as well as demand for products of particular industries	Greater economic growth and demand could encourage plant upgrades or replacement with new facilities that use cleaner technologies. The former would increase opportunities for NSR.
	Prices of different fuels and other inputs to production for an industry	Higher prices would discourage new investments, except for those designed to allow for greater fuel efficiency or fuel or input switching. This could lead to fewer candidate projects for NSR in some industries, while in other industries, efforts may be made to extend the life of facilities using lower-priced fuels (for example, coal).
Regulatory and judicial decisions	Uncertainty in future air-pollution-control programs such as Clean Air Interstate Rule and Clean Air Mercury Rule	Implementation of tight nationwide or regional caps (with trading) could lessen the importance of NSR as a tool for reducing national or regional emissions but would not affect NSR's role in safeguarding local air quality.
	Uncertainty in the effect of differential environmental regulation for new sources on the rate of technological change and associated pollution reductions	Tighter environmental regulations for new sources result in new facilities with lower emissions but may encourage companies to prolong the life of old facilities (with higher emissions) and delay investments in new plants.

continues

TABLE 4-2 Continued

Domain	Uncertain Element	Implications for Assessing NSR Effects
	Uncertainty in trading program outcomes and enforcement decisions for particular facilities	Although national or regional caps may limit effects on total emissions, local hot spots of increased emissions could develop and more-lenient NSR rules could allow them to persist. This could have implications for local air quality, exposure, and health.[a]
	Other industry constraints such as Public Utility Commission (PUC) regulations for electric utilities	These could constrain decisions on maintenance and repair, limiting the firm to a smaller set of investment alternatives.
Existing facility responses to NSR implementation	Uncertainty in specific aspects of the NSR implementation procedures under the pre-2002 rules, especially the extent to which states allowed firms to use periods prior to the previous 2-year period for computing prechange emissions. The definition of "routine maintenance" that will be applied by courts reviewing NSR cases	Greater leniency under the pre-2002 rules implies less difference between the pre-2002 and the current rules. The greater the scope of the term "routine maintenance" that is applied, the fewer projects will come under the purview of NSR. This will also affect the number of cases where the surrender of allowances is part of the settlement.
	Uncertainty as to whether firms will be effectively limited to projected annual emissions	If projected emissions underestimate actual emissions, the new rules could allow for a facility's emissions to increase.
	Uncertainty in number of firms that will take advantage of plantwide applicability limits (PALs) and how firms with PALs will behave	Greater adoption of PALs could either lead to adopting firms maintaining their emissions within currents caps (and possibly avoiding NSR, which would lead to further reductions in emissions) or to the adoption of additional pollution controls to stay within their caps, thereby limiting the potential for emission increases by these companies.

TABLE 4-2 Continued

Domain	Uncertain Element	Implications for Assessing NSR Effects
Air quality	National trends and local ambient concentrations of sulfur dioxide, nitrogen oxides, ozone, and particulate matter. Uncertainty exists in modeling the relationship between changes in local or regional emissions and changes in ambient air concentrations at specific geographic locations	Improvements in national trends for ambient air pollutants would suggest that ongoing cap-and-trade programs are having a net, beneficial effect on national air quality. The persistence (or worsening) of local hot spots with elevated air-pollution concentrations would suggest the need for additional efforts to identify the sources responsible for these higher concentrations and the application of tighter regulation of these sources (through NSR enforcement or other mechanisms).
Exposure and health	National and local trends in exposure to air pollutants and resulting health effects. Uncertainty exists in determining the marginal impacts of concentration changes on health outcomes, given uncertainty regarding the exposure and dose-response relationships for some pollutants and pollutant mixtures.	Changes in national and local exposures and attributable health effects should be studied in an ongoing manner to verify the benefits of NSR or other air-pollution-control regulations.

[a]While concerns about the generation of local hot spots from regional or national cap-and-trade programs remain, a number of proponents of this approach have noted that significant hot spots did not develop as a result of the national trading emissions under the Clean Air Act acid-rain-control program (Ellerman et al. 2000; Swift 2000), and that other trading programs have had similar success, with the possible exception of the California RECLAIM program for mobile sources and an open market trading program in New Jersey (Farrell and Lave 2004).

encourage the building of new plants with cleaner technologies and could again exacerbate the difference in emissions between existing plants that avoid NSR and those that undergo the review. Higher prices for production inputs would discourage new investments, increasing the number of facilities that maintain, repair, or replace, thereby increasing the pool of facilities for which maintenance and repair projects might or might not trigger NSR, depending on how the NSR rules are defined and interpreted.

A number of regulatory and judicial uncertainties also make it difficult to assess the likely effects of the proposed NSR rule changes. First, there is fundamental disagreement about whether stricter new-source pollution controls result in a net reduction in emissions as new facilities are added to the production base, or instead result in higher emissions (at least over the short term), because the construction of new, cleaner facilities is discouraged by the tight emission standards. In addition, uncertainty in future air-pollution-control programs such as the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) limits the ability to predict whether national or regional caps will control total emissions independent of NSR or whether stricter NSR enforcement could reduce emissions below planned caps. Uncertainty in the specific outcomes of trading programs limits the ability to identify local increases in emissions that might be avoided with strict NSR rules and enforcement. Effects on ambient concentrations, exposures, and health effects associated with any such hot spots are likewise uncertain because of uncertainties in the geographical distribution of emissions as well as limitations in the basic science needed to predict these outcomes. Similarly, industry constraints due to other regulations or rules could limit the applicability of NSR rules.

There is significant uncertainty in the behavioral response of firms to a number of the 2002 changes in the NSR rules, including the demand growth exclusion, the procedure for computing prechange emissions, the use of projected actual emissions to assess a project's impact, and the decision to allow plants to apply for plantwide applicability limits (PALs). EPA is also considering revisions in its rules that might further affect NSR applicability. Finally, the courts have yet to resolve such key issues as the criteria for deciding whether a given project is routine maintenance, repair, and replacement and hence exempt from NSR, or how to calculate whether an emissions increase will result from a physical change.

Additional uncertainties are present with respect to ambient-air-pollution concentrations and how these are affected by local versus regional emissions, and with respect to the human exposures and health effects that result. Further data collection and advancements in modeling tools should allow better estimates of changes in ambient concentrations, exposures, and health effects that can be expected to occur from a particular future emission scenario.

ECONOMETRIC METHODS

Econometric methods involve the formulation and fitting of models for firm behavior, such as emissions, energy use, and production. Consider the general formulation for an econometric model. Given observations of policy X and an outcome Y, we can use econometrics to measure the effect of X on Y by estimating the function Y = f(X,Z), where Z represents other measured factors that influence Y. A linear representation of function f is

$$Y_i = a + bX_i + cZ_i + e_i, \tag{4-1}$$

where i refers to each observation in the dataset; a, b, and c are parameters of the model; and e is an error term. We can think of e as the composite of all other factors that influence Y and are not measured in X or Z and the inherent limit on precisely measuring Y_i. Parameter b represents the effect of the policy on the outcome.

Key assumptions for measuring b validly are that we can observe Y and X and that policy X is not correlated with the error term e. The latter assumption matters because the estimation procedure will tend to attribute as much of the variation in Y as possible to the influence of the measured variables (X and Z). If X is correlated with e, the estimate of b will be biased. For example, if policy X happened to be implemented primarily in locations where e was high, the estimation would give credit for those high e values to policy X, and the estimated value of b would be too high. In an experimental setting, we could vary X independently of Z (and e), avoiding this problem and yielding an unbiased measure of b. Instead, the econometrician must rely on a good understanding of the process generating Y and any likely sources of bias and must include a sufficient set of control variables Z to capture other important factors affecting Y and to render negligible the bias caused by the remaining unmeasured factors. The inclusion of control variables, Z, can also be augmented by use of propensity scores to reweight the analysis and remove bias (Rosenbaum and Rubin 1983; Imbens 2000).

Two types of econometric models will be considered here. A structural or behavioral model focuses on the underlying decision being made by the firm—in this case, whether to proceed with a given investment project that may be subject to NSR requirements. This type of model includes measures of the characteristics of the applicable NSR rules, allowing estimation of the effect of variations in these rules on the specific investment decision. A second approach—a reduced-form model—focuses on broader outcomes, such as total investment spending or emissions from the firm, rather than individual investment projects.

Structural or Behavioral Models

Suppose we wished to estimate directly the effects of NSR stringency on a firm's individual investment decisions in what is called a structural or behavioral model. Conceptually, we would identify each potential investment project that a firm could make, a measure of the NSR stringency (X) the firm faced, and other factors (Z) affecting the investment decision. The outcome (Y) would indicate the firm's decision on each specific investment project: Did the firm get an NSR permit, avoid NSR by modifying the project in some way, or choose not to make any investment at all? The relation between NSR stringency and the firm's investment decisions (parameter b) could differ among categories of investment projects. If X measures greater NSR stringency, we would expect to find a negative value of b (more stringent NSR reducing the likelihood of pursuing an investment project), although some smaller types of investment projects might become more likely (b positive) if larger projects were being discouraged by NSR. The 2002 and 2003 NSR changes, by making it easier for investments to avoid NSR requirements, should reduce X and therefore increase some types of investment. A detailed-enough model of the investment decision incorporating NSR might be able to predict the difference in investment decisions after the NSR rules changed. If the measures of policy stringency are sufficiently detailed (perhaps using several X variables, measuring such items as the delay required to get an NSR permit, the level of control equipment required, and the cost of consultant services needed to complete the permit application), the model could predict the effect of a wide variety of changes in NSR rules, not just the changes that actually occurred.

An appropriate structural model should include consideration of all possible factors outside the realm of NSR rules that could influence maintenance and retrofitting behavior by firms (the Z terms in Equation 4-1), including other regulations, general economic conditions, the adoption by firms of nonregulated emission-control measures (for example, for greenhouse gases or mercury), and uncertainty in future regulation due to legal challenges and pending rule making. Differences across industries may also be important. Firms in industries with rapidly expanding demand and high profit potential may be especially willing to invest in both plant expansion and pollution-control measures to ensure a quick "speed-to-market."

Econometrically estimating a structural model of this sort faces several obstacles. The greatest difficulty is that many of the necessary data are unavailable and could not plausibly be made available; we would need information on potential investment projects that were never carried out and information on projects that were modified to avoid NSR. It is hard to imagine getting such data in complete form, especially because changes in NSR might change the projects being considered by a firm, even for planning purposes. Anecdotal information could be used to identify the types of investment projects that are being discouraged by NSR requirements, but firms could have an incentive to exaggerate these cases so that they could argue for less stringent NSR rules. In any event, it would be impossible to quantify the overall effect of the NSR changes with an anecdotal approach. Aside from the anecdotal information, one cannot observe anything about discouraged projects (not even their existence), so one cannot tell whether they would have caused a facility's emissions to increase or decrease.

Even if we limit ourselves to investment projects that actually occurred, only a fraction will have required an NSR permit. Some modification projects may require some form of minor state permit, and perhaps there would be discussions between a firm and state regulators about what could be done to avoid the NSR permitting process. Still, it seems unlikely that much of such permit discussions would be captured in state records, and it would be difficult to identify the extent to which a firm might have modified a project on the basis of the firm's understanding of NSR requirements, even before talking to the regulators.

Collecting those state data, either on past minor permits from state files or on future minor permits, would involve considerable effort. Even the data on projects that get NSR permits are not immediately available; it took some effort for EPA to collect basic information on a set of NSR permits using files kept at EPA regional offices. Running an analysis on only facilities with NSR permits and then defining required emission reductions as the "effect" of NSR would be to ignore the investment disincentives mentioned above and could present a picture that is misleading with respect to the sign of the effect, let alone its magnitude.

Reduced-Form Models

If we cannot estimate a structural or behavioral model of individual investment decisions, what can we do? The answer may lie with an alternative approach known as a reduced-form analysis. In a reduced-form model, we identify one set of facilities that was covered by the revised NSR requirements (the "experimental" group) and compare the outcome with the outcomes at another set that was still covered by the prerevision requirements (the "control" group). We can then test whether the two sets of facilities differ in such outcomes as emissions, investment rates, and other observable characteristics without explicitly modeling decisions on individual investment projects. Given large enough sets of facilities and a large enough effect of the NSR rule changes on the outcome, we should see some differences in outcomes between the sets of facilities.[1]

The reduced-form approach has the advantage of not requiring micro-level investment data and focuses our attention on differences in aggregate outcome measures, which may be easier to observe than outcomes of individual projects. However, it requires us to be able to identify two sets of observations: one of facilities operating under the prerevision NSR requirements and the other of facilities operating under the new NSR rules. The analysis could take advantage of three sources of variation, leading to three approaches: time series, cross section, and difference in differences.

[1]This type of analysis could only be conducted using observed investment behavior during a limited window of time, because presumably all states will eventually be under the same set of rules.

A time-series approach would compare the same facilities before and after the NSR rule changes: if the rules changed in 2003, compare data on 2000-2002 with data on 2004-2005 and ascribe any differences to the NSR rule changes. Such estimates could be biased if other unmeasured factors (the error term e in Equation 4-1) changed over the same period and either encouraged or discouraged investment. For example, the recession in 2000 may have discouraged investment for a few years, so increases in investment after 2003 might be mistakenly ascribed to the NSR rule changes rather than to improvements in the macroeconomic environment. Controlling for such confounding factors, whether arising from economic forces or other regulatory initiatives, is an important part of any econometric analysis.

A cross-section approach would compare the outcome measures (facility-level investment activity and emission levels) across facilities at the same time. The analysis requires some facilities to be located in states already affected by the NSR rule changes and some facilities to be in states not yet affected. Possible confounding factors for cross-section analysis include other (non-NSR) differences in regulatory stringency across states being correlated with states that had implemented the NSR rule changes.

A difference-in-differences approach would combine the time-series and cross-sectional approaches by calculating changes in outcome variables over time (like time series) and then comparing those changes across states (like cross section). The statistical evaluations would measure whether the timing of outcome changes coincided with the timing of the rules change. Because the analysis includes different sets of facilities in the same year, some affected by the policy change and some not affected, nationwide changes in economic performance or regulatory initiatives would be less likely to bias the results. Because the difference-in-differences analysis looks at changes in outcome variables over time, long-run differences in (non-NSR) regulatory stringency across states are less likely to bias the results.

The main disadvantage of a reduced-form model relative to a structural model is that we do not gain as much insight into the determinants of the decision-making process. In contrast, a properly specified structural model could allow us to extrapolate from the effect of these NSR rule changes on investment decisions to provide estimates of the effect on investment decisions if the NSR rule changes had been different. However, structural models for particular industries may yield very different results. Given that the goal of this project is to offer suggestions about how to measure the effects of the NSR rule changes as they actually occurred, the limited ability to make generalizations on the basis of the reduced-form model is less critical here.

Existing Econometric Results

The essence of the argument that the NSR rule changes will improve environmental performance is based on an understanding of how firms respond to differences in regulation between existing and renovated facilities. In particular, if investment in new production equipment would trigger NSR rules requiring the installation of expensive pollution-control equipment, or if going through NSR review would add considerable delays and uncertainty to the investment process, firms might choose not to pursue these investment projects. In many cases, new production equipment would be less polluting than the older equipment it replaces (as well as more efficient), so some reduction in pollution could have resulted from investing in new equipment, even if no additional pollution-control equipment were installed. Changes in NSR rules that made it clear that certain investment projects would not trigger NSR would make such projects more attractive: reducing the cost of control equipment and reducing delays and uncertainties due to NSR review. If NSR sufficiently discourages modifications to existing plants, the environmental gains from imposing stricter controls on investments that do proceed could be outweighed by the environmental losses from the forgone modifications. Research has examined how firms respond to spatial and vintage-related differences in regulations when making decisions on opening and closing facilities and on investment in existing facilities. These decisions are also affected by many other factors that vary from one location to another, including labor conditions and local taxes, and these confounding factors (Z terms in Equation 4-1) must be considered to obtain an unbiased estimate of the impact of the regulation. None of the research applies directly to the new NSR rule changes, but it can provide insight into how the rule changes might matter.

Spatial differences in regulation arise primarily from stricter NSR and other regulatory requirements in nonattainment areas, although states may also differ in their overall regulatory stringency. Levinson (1996) used a conditional logit model and Census Bureau facility-level data to study whether births of new manufacturing plants in the 1990s responded to differences in state environmental regulations and found only limited effects, controlling for other factors affecting plant location decisions such as unionization, wage levels, and tax rates. Becker and Henderson (2000) studied the effects of ozone attainment status on investment decisions at facilities in four manufacturing sectors that emit high levels of volatile organic compounds (VOCs), using Census Bureau facility-level data for 1963-1992. They found that new plants were more likely to locate in attainment areas, and there were more new plants in the small-scale nonaffiliate sector (less likely to face strict regulation) than in the corporate sector. Their analysis focused on changes over time in which counties attracted more plants, implicitly controlling for other differences across counties that might affect the location decision.

Other econometric studies have examined the effect on economic decisions of differential regulation of sources due to vintage (for example, existing versus new). Stavins (2005) reviews several such studies, which generally find that those regulations discourage new investment. Gruenspecht (1982) looked at the effects of corporate average fuel economy (CAFE) standards[2] on turnover of the automobile fleet and found that applying tighter standards to new cars reduces the rate of turnover and thus increases the average age of cars on the road; the net effect on fleetwide emissions was not estimated. Maloney and Brady (1988) used data on electricity-generation-facilities investment in 1956-1982 and found that air-quality regulations reduced the rate of new plant investment and resulted in a 25% older capital stock; they concluded that the overall effect of regulation was to increase sulfur dioxide (SO_2) emissions. Nelson et al. (1993) related the average age of the capital stock of a group of 45 electricity-generating facilities in 1969-1983 to measures of demand and input-price growth and to regulatory intensity; they found that differential regulations resulted in a capital stock that was 23% older, but in their dataset, older plants were not significantly dirtier than newer plants, so there was no increase in emissions. These articles do not base their analyses on time-series variation in investment and regulation, which might have confounded the 1970s growth in regulation with the slowdown in electricity demand. Instead, they use differences in regulatory stringency across states, measured by spending by state air-quality-management agencies and other measures, and find that facilities in stricter states do not replace their equipment as quickly, leading to an older capital stock.

The Becker and Henderson (2000) study mentioned earlier also examined the time pattern of investments at a facility. They found that new facilities in nonattainment areas started out larger but received less additional investment than new facilities in attainment areas, whereas existing facilities in attainment areas were less likely to survive than those in nonattainment areas. They concluded that stricter NSR rules discouraged modifications and encouraged older plants to remain in operation, potentially increasing emissions (they did not measure emissions directly). List et al. (2004) used data for 1980-1990 from the New York State Department of Economic Development to analyze the relationship between plant alteration and closure decisions and county attainment status as a proxy for stringency of NSR

[2]CAFE standards, which were initiated by Congress in the Energy Policy and Conservation Act of 1975, established mandatory fuel efficiencies in the form of required miles-per-gallon goals for fleets of passenger cars and light-duty trucks.

requirements;[3] they found that NSR appears to retard alteration of existing plants but found little evidence that NSR affects the closure of existing plants (their study did not include emission levels).

Taken as a whole, those results indicate that the NSR rules before the 2002-2003 rule changes tended to discourage investment in new facilities and in renovations of existing facilities. That suggests that the NSR rule changes, which exempted some renovations, would tend to encourage renovations of existing facilities. Full repowering—that is, replacing an old facility with a new one, might also be encouraged—because this would allow for significantly higher capacity at the same level of emissions. Nonetheless, it is possible that the NSR rule changes, by making it easier for old sources to renovate, could discourage the construction of new facilities even more, potentially offsetting any beneficial effects of encouraging investment at old facilities.

PROCESS-ENGINEERING MODELS

Many of the modeling approaches described in this chapter deal with multiple facilities and their interactions or use simplified characterizations of production technologies that merge multiple processes into a single-stage production function. However, such models often lack details about technological characteristics. For example, many life-cycle inventory and market-analysis models use linear coefficients for the ratio of energy consumption to delivered units of a particular product or for the ratio of emissions to a particular product. In reality, energy consumption and emissions at specific facilities can be a complex function of site conditions, feedstocks, process configurations, designs of process areas, operating practices, and maintenance. Furthermore, when retrofit options are being evaluated, the availability of space at a site can severely constrain the location of additions to a plant and thereby affect cost. Thus, there can be a need for a model or evaluation at the level of an individual plant that takes details of the plant's major components into account. Such models can allow "what if" analysis of effects of changes in design, feedstock composition, and operations on efficiency, emissions, and cost at the level of an individual plant.

The numerous plant-level modeling approaches range from empirical to theoretical. An empirical approach typically involves fitting a regression equation or system of equations to available data on the inputs and outputs of individual process areas and linking the process-area models together to describe an entire plant. A theoretical approach involves developing mass and energy balances for each process area, including detailed chemistry

[3]The study by List et al. (2004) focuses on NSR rules in effect before the recent changes that are the subject of this report.

(such as chemical kinetics) and physics (such as fluid flow) for each unit operation. For example, the furnace of a power plant could be simulated by using computational fluid dynamics coupled with a chemical mechanism that describes the combustion of fuel and formation of pollutants during combustion. Such a simulation would make it possible to describe the temperature field in three dimensions in the combustor and dynamically. Such models can be both data-intensive and computationally intensive. If the same approach is applied to all process areas of a complex plant, the resulting model can be large and difficult to use. Thus, the choice of an appropriate modeling approach depends on the objectives of the model.

Commercially available software tools, such as the ASPEN Plus (AspenTech 2005) steady-state chemical-process simulator, can be used to develop and apply simulation models of a wide variety of process plants. The user specifies key parameters of each unit operation and of the inlet streams. Thermodynamic databases describe the key physical and chemical properties of each chemical "component," such as compounds. ASPEN or ASPEN Plus models have been developed for a variety of power-generation systems, for example, integrated gasification combined-cycle systems (Frey and Rubin 1992). Cost models of process technologies can be developed by using built-in features of ASPEN or developed separately and coupled with the performance model as subroutines. ASPEN Plus simulation models require software-specific expertise to develop and run. It has been shown that simplified reduced-form models can be developed on the basis of ASPEN models, which in turn facilitate more rapid analyses useful for policy purposes (Frey and Bharvirkar 1998).

To be of practical use, process-engineering models of plants should be executable in a reasonably short period by users who are not experts in the model. An example is the Integrated Environmental Control Model (IECM), which runs in a Microsoft Windows environment and has a graphic user interface (Rubin et al. 1997). In the past, EPA developed and maintained a somewhat similar model, known as the Integrated Air Pollution Control System (IAPCS) (Radian 1999). However, IECM and IAPCS typically had a somewhat different technology focus, and IECM includes a distinguishing probabilistic simulation capability for quantifying uncertainty in inputs and outputs.

A key goal of plant-level models intended for policy applications is to capture salient details and key interactions among process areas without becoming unwieldy. One approach, used in the IECM and similar models, is to start with basic mass and energy balances for major "process areas" of the plant to describe, with adequate accuracy, the major mass and energy flows in the plant. For example, the major process areas of a new coal-fired electric-power plant typically include the boiler, economizer, air preheater, particulate matter (PM) control device (typically a cold-side electrostatic precipitator or fabric filter), nitrogen oxide (NO_x) control devices (typically a low-NO_x burner or other combustion-based approaches and perhaps a postcombustion selective catalytic reduction system, CRS), an SO_2 control strategy (for example, use of a low-sulfur fuel or postcombustion flue-gas desulfurization, FGD), a steam cycle (including heat exchangers, steam drums, steam turbines, and condensers), and other special considerations (such as mercury control with carbon injection). For each major process area of the plant, a separate mass and energy balance model is developed. The process areas are interconnected by the flow of mass and energy between them.

Process models, like econometric and other models, are subject to uncertainty. Uncertainty in a process model is associated with a lack of knowledge regarding the performance, emissions, and cost of a facility, either because necessary data are not available or because predictions are being made for future outcomes. Uncertainty is also influenced by the state of development of the technology and the level of detail of the estimation method. Furthermore, individual process technologies are subject not only to uncertainty but to variability in feedstock composition, unit costs of consumables, and the performance of unit operations. In addition, even when comparing facilities of a similar type, there is variability in design, operation, and maintenance from one facility to another. Thus, there are many sources of inter- and intraplant variation. Methods have been developed to make statistical estimates of variability and uncertainty as part of process technology models of electricity-generating facilities, and such models also include the option to simulate alternative system designs. It is possible to develop such models when the design basis of such options is relatively well known and reported. However, for nonelectricity-generator sectors, such as in manufacturing, there may be less nonproprietary information available upon which to base a process model, and there may be greater interplant variability such that it is difficult to develop a single model that captures the diversity of configurations and modifications that may occur in response to changing economic or regulatory conditions. Clearly, there are examples of nonproprietary process models that have been developed for various nonelectricity-generating sectors, typically to evaluate performance, emissions, and cost of specific design options, but an integrated framework for evaluation of variation in plant design and operation, combined with quantitative assessment of uncertainty, is still lacking.

Plant-level models can be incorporated into a larger simulation framework. That has been done in the past, such as for the advanced utility simulation model (e.g., Cole and Chapman 1983), to support systemwide planning applications that take into account some of the details of design and operation of individual plants, as well as systemwide considerations (e.g., Badger and Ojalvo 1988). The "bottom up" sectorwide models discussed in the next section are of this type.

ASSESSMENT OF SECTORWIDE RESPONSE

General Framework for Sectoral Assessment

The response of a full industrial sector to regulation can be estimated with generalizations of the tools used for individual firms, potentially including anecdotal reports and representative case studies or surveys. In addition, economic models are available to estimate the behavior of multiple plants or facilities that may or may not interact in some way in response to common constraints and incentives. The models are most often applied to electric-power generation, including short-term dispatch and long-term capital investment and technology adoption in response to future demand, prices, and regulation.

The purpose of sectoral assessments is to project the possible response of an entire sector of U.S. industry to scenarios involving government policies, technological change, and economic conditions. The major difference between sectoral assessments and individual firm analyses is that sectoral assessments aggregate the actions of all firms in an industry while imposing consistency conditions that must be met by the market as a whole. Those conditions usually require that markets clear—that is, that prices adjust so that supply equals demand for the sector's inputs and outputs.[4]

In the case of outputs, an example of such a market-clearing condition is that the quantity of electric power produced by a region's power plants equals the quantity consumed by the region's consumers, adjusted for net imports. By imposing such a condition, a sectoral analysis ensures that, for example, if one facility or set of facilities greatly increases output (and emissions) in response to a change in NSR rules, some other facility or set of facilities will need to decrease production (and possibly emissions). A sectoral analysis can also account for the effect of price changes on demand so that, for instance, demand increases stimulated by lower prices could also consume and assimilate some of the increased production.

In the case of inputs, market clearing ensures that the aggregate demand by the sector for fuel or emission allowances, for example, is consistent with the amount available. Continuing with the power-industry example, a national cap on SO_2 emissions under Title IV of the 1990 Clean Air Act amendments implies that, if the cap is binding, an increase in emissions from

[4]Sector models are also limited in their ability to track or predict other aspects of firm-specific behavior, such as the performance improvements that result from site-specific process adjustments or learning by doing.

one group of facilities must be matched by a decrease somewhere else or, because of allowance-banking provisions, at some other time in the future. Conversely, if emission allowances have a positive price and if a regulatory action forces a power plant to reduce its emissions and the plant is allowed to sell the resulting excess allowances rather than surrender them, the result will be an increase in emissions at another location or at another time. That outcome would not occur if, as part of the settlement agreement imposed by the regulatory action, the allowances are eliminated.[5] Because the supplies of some sectoral inputs, especially fuels, respond to price, increases in inputs demanded by one set of facilities can be met by decreases in use by other facilities and by an increase in supply. Thus, for instance, if an emission policy motivates a shift in fuel from coal to natural gas, prices for coal will fall, shrinking its supply, and prices for natural gas will increase, stimulating an increase in its supply. The resulting redistribution of fuel use (and emissions) among the nation's power plants will reflect a balancing of supply of and demand for the fuels and allowances. The purpose of sectoral analyses is to project those shifts in a way that is consistent with the operation of the sector's input and output markets.

However, sectoral assessments do not attempt to trace the effects of a policy change throughout all sectors of the economy. For instance, changes in energy use and emissions by railroads due to a change in the power industry's demand for low-sulfur western coal might be significant but would not be considered in a power-sector assessment.

Previous Applications of Sectoral Models for the Electric-Power Industry to Assess New Source Review Rule Changes

In EPA (2003b), the impact of the October 2003 equipment replacement rule (ERP) upon power generation emissions was projected in two separate sets of analyses. One used EPA's Integrated Planning Model (IPM), while the other utilized the National Energy Modeling System (NEMS) of the U.S. Energy Information Agency. Both analyses are summarized below.

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[5]In a statement regarding the surrendering of emission allowances as part of settlement agreements, a recent report of EPA's inspector general's office notes that (EPA 2004c)

> When controls are installed, excess allowances of SO_2 emissions are created, and it is vital that these allowances not be used. Consequently, all seven settlement agreements included an Emissions Trading Clause requiring the company not to use or sell any emission reductions. Also, all the settlement agreements required the surrender of allowances, except for Tampa Electricity-Power, which prohibited the selling and trading of SO_2 allowances. If a facility is able to use allowances elsewhere at a plant or sell them to another facility, there will be no environmental benefit achieved.

Further discussion of the role of allowance surrenders in NSR settlements is found in Chapter 2.

IPM Analysis

The IPM-based regulatory impact analysis of the NSR rule change consisted of a comparison of two sets of IPM solutions, defined as follows:

- A base case in which the previous NSR rules (in particular, those concerning routine maintenance exclusions) remain in force. EPA assumed that if a power-generation facility faced a decision about a repair or maintenance project, the facility would only opt to go forward with the project if it would clearly not trigger NSR. Thus, it was assumed that the expense of the project, including compliance with NSR, would never be justified by the net increase in energy and emission allowance revenues that would accrue because of the facility's more efficient operation. EPA assumed that the result would be a deterioration over time in fuel-use efficiency and capacity of existing coal-fired plants, and that the recent trend towards improvement in plant availability would slacken. IPM automatically retires those facilities whose efficiencies and going-forward costs render them uneconomical under projected power prices.
- A set of five increased maintenance cases, based upon an assumption that the proposed changes in the NSR rules would result in existing coal-fired plants undertaking more maintenance. These plants' fuel-use efficiencies, capacities, and availabilities were assumed to have a higher trend than in the base case. The assumed increases in efficiency and capacity over the base cases ranged up to 3.2%, and the range of availability improvements considered was 0-3.4%. Ranges were considered because the precise amount of incremental maintenance and its exact effect cannot be confidently forecast.

Although the clean unit and PAL features of the NSR rule changes may also be taken advantage of by power generators, their impact was not considered in these solutions.[6] It is important to note that it was not possible to tailor the efficiency, capacity, and availability assumptions to the particular circumstances of individual facilities, because it is unknown what the potential projects are at each plant, nor their effects. Rather, the intent of this analysis was to show what the implications would be of different trends for plant efficiency, capacity, and availability, under the assumption that the major impact of NSR rule changes would be to shift those trends upwards.

[6]Furthermore, the clean-unit provisions of the 2002 rule changes have now been invalidated.

The major conclusions of the comparison of these IPM cases were as follows:

- Total SO_2 emissions over the period of 2005-2020 would not change, remaining, on average, at the national cap, plus allowances that were banked from previous years. Because of banking, there were some slight shifts of emissions from year to year. In none of the cases is so much coal capacity retired that the cap on SO_2 emissions is no longer binding.
- NO_x emissions change more than SO_2 because they are capped only in some regions for some portion of the year. The five increased maintenance cases were reported to have varying effects for the years 2005, 2010, 2015, and 2020, ranging from a decrease of less than 1% to a 2% increase. The varying results represent shifts in the relative importance of efficiency improvements (which lower NO_x emissions by decreasing fuel use per megawatt-hour [MWh]) relative to capacity and availability improvements (which can increase NO_x emissions by allowing the output of relatively high-emission older units to expand, at least in times and places that such emissions are not capped).
- The improved performance due to higher maintenance would save $100 million to $2,500 million in 2005 and between $2,000 million and $3,900 million in 2020. However, these savings include only decreases in fuel costs and investments in major retrofits and new plants. They do not include the higher expenditures on maintenance that would occur under the new NSR rules, so the net savings would be less than these values.

Given the presence of binding emission caps for SO_2 (nationally) and NO_x (only in the 22 eastern states for the ozone season), and the assumption that the main effect of NSR rule changes would be to increase the amount of maintenance and, consequently, the efficiency and capacity of existing plants, these relatively small changes in national emissions are what should be expected.

Alternative assumptions about the impact of NSR could, however, change these results. In particular, one such alternative assumption might be that the prerevision NSR policy would result in retrofits of flue-gas desulfurization or other major New Source Performance Standard–compliant retrofits that otherwise would not take place. The above base case does not show this happening because, under the model's assumptions, plant owners will choose to accept deterioration in performance rather than undergoing major retrofits, which are assigned a capital cost in IPM. If, on the other hand, it was assumed as part of the base case that a large number of existing coal plants would eventually deteriorate in performance so far that the only options would be retiring the plant or investing in a costly retrofit that would trigger NSR-required reductions in emissions, we might get different results—many more retrofits and retirements in the base case, with the possibility that the NSR rules changes would result in higher emissions than the (new) base case. Such a scenario is considered in our analyses utilizing the IPM model, found in Chapter 6.[7]

NEMS Analysis

EPA (2003b) also provides an analysis of the ERP undertaken using the NEMS (EIA 2003b). An additional set of NEMS analyses was also undertaken by the U.S. Department of Energy (DOE) (D. Carter, DOE, unpublished material, Aug 21, 2003). Both NEMS analyses are summarized here.

NEMS is an interconnected suite of models for various components of the U.S. energy sector, as well as models of the remainder of the U.S. macroeconomy and world energy markets (EIA 2003b). The model searches for a set of prices and quantities supplied and demanded that represents an equilibrium among modules representing oil and natural gas supply, natural gas transmission, coal supply, renewable fuels supply, electricity generation, petroleum fuels processing, and energy demands by residential, commercial, transportation, and industrial customers. The modules can also be run in stand-alone fashion, for example, for just the electricity sector subject to fixed energy demands. NEMS breaks down the results by nine Census divisions and provides projections through the year 2025.

Similar to the IPM analysis, the impact of NSR rule changes upon the electric-power sector was assessed by NEMS in EPA (2003b) by assuming that the changes would encourage more maintenance in the industry, yielding improvements in the efficiency and availability of existing coal-fired power plants. Three higher maintenance scenarios were simulated, as well as a base case. Like the IPM analysis, the base case reflects an assumption that the existing coal plants would opt to avoid NSR, and so performance would not improve as much as in the higher maintenance scenarios. The ranges of values considered in the higher maintenance cases were a 5-15% improvement in fuel-use efficiency and a 0-5% improvement in availability, although additional generation by existing units was capped assuming that they would use no more fuel than in the base case. That capping served to diminish the impact of additional capacity upon output and emissions of existing coal plants. A comparison of the base and higher maintenance cases for 2010 and 2020 resulted in the following conclusions about the effect of the proposed NSR rule changes:

[7]In our analysis in Chapter 6, we allow for plants to retrofit scrubbers, retool, or retire, although not in response to a modeled deterioration in performance, but rather as a surrogate for stricter NSR enforcement.

- SO_2 emissions would be unchanged, remaining at the cap except in early years when allowances banked from Phase I of Title IV are consumed.
- The increased maintenance cases were reported to have varying effects on NO_x emissions, ranging from a decrease of approximately 10% to a slight (1% or less) increase. As in the IPM analysis, the net effect depends on the extent to which the impact of efficiency improvements (which lower NO_x emissions) offsets the impact of capacity and availability improvements (which can increase emissions).
- Regarding unregulated emissions, CO_2 emissions fall in all of the increased maintenance cases by as much as 10% or more. Mercury emissions fall, except in one case when capacity improvements were at their highest assumed value and efficiency improvements were at their lowest. Variations in mercury emissions among the scenarios were generally below 10%.
- No cost impacts were reported.

The above ranges of emission impacts are much larger than the IPM analysis because the assumed performance improvements are much greater. EPA (2003b) did caution that the higher assumptions concerning efficiency improvements may not be technologically or economically feasible. However, the central result—that the existence of emission caps dampens or eliminates changes in SO_2 and NO_x emissions—is the same as the IPM analysis.

The later DOE (2003) analysis using NEMS considered a narrower range of fuel efficiencies (5% and 10% improvements) and availabilities (0-2%). The earlier NEMS analysis did not consider capacity improvements, but the second analysis assumed an improvement in capacity equal to one-half the efficiency improvement. These changes did not materially alter the SO_2 and NO_x conclusions of the earlier NEMS analysis; cumulative SO_2 emissions were unchanged, and annual NO_x emissions differed from the base case by –6% to +0.2%. The later analysis did quantify cost savings, net of an assumed cost of $100/kW for capacity increases, yielding cumulative cost savings over the 24-year simulation of between $10 billion and $100 billion.

Like the IPM analyses, the NEMS analyses assumed that, under present NSR rules, owners of coal-fired power plants would be able to avoid triggering NSR by forgoing large maintenance expenditures. As noted above, we consider in Chapter 6 a different set of conditions in which plants are forced to retire or meet stricter emission standards (through scrubbing).

A RETROSPECTIVE STATISTICAL ANALYSIS OF RELATIVE EMISSION CHANGES

In Chapter 5, we consider the data needs for an effective econometric model that could address whether stricter enforcement of NSR tends to reduce or increase emissions by industry. As a preliminary statistical analysis, we evaluated changes in available reported emissions by industry in the National Emissions Inventory (NEI) for 2 years, 1989 and 1998, in each case relative to the reported emissions in the 2 previous years.

The analysis illustrates methods that could be used to better understand the distribution of actual emission changes that have occurred at different times. The analysis compares the reported emissions in 1989 and 1998 to the emissions reported for the 2 previous years, 1987 and 1988, and 1996 and 1997, respectively. This is appropriate, because the average of the previous 2 years had, until the December 2002 NSR rule change, served as the baseline for determining whether a significant increase in emissions had occurred.[8] The December 2002 NSR rule change allows the use of any consecutive 24-month period during the previous 10 years.

In the October 2003 report, "Reform or Rollback? How EPA's Changes to New Source Review Could Affect Air Pollution in 12 States," the Environmental Integrity Project (EIP) and the Council of State Governments/Eastern Regional Conference (CSG/ERC) conducted an analysis of historic emissions data from industrial sources to determine the potential impact of the use of a 10-year baseline period for deciding whether an emission increase at a facility triggers a NSR (EIP and CSG/ERC 2003). The study evaluated emissions from major sources of criteria pollutants, i.e., those with pollutant-specific emissions greater than 100 or 250 tons per year, depending on the source category of the plant (electric-power plants were not included in the analysis, since the proposed rule change allowing the 10-year look-back period does not apply to electricity-generating facilities). The data include annual emissions of particulate matter, nitrogen oxides, sulfur dioxide, VOCs, and carbon monoxide for periods ranging from 6 to 10 years. The results indicate significant potential emission increases allowable as a result of the switch from the 2-year to 10-year baseline period. For the 1,273 facilities considered, a total allowable increase of 1.4 million tons per year is computed across the five pollutants and the 12 states. In the following we present the results of an analysis that we conducted of actual changes in emissions from the NEI.

Emission data for two 3-year periods, 1987-1989 and 1996-1998, were obtained from the NEI database. The NEI contains information about

[8]Some flexibility for using earlier time periods for the baseline calculation may have been allowed in certain circumstances and states.

sources that emit criteria air pollutants and their precursors, and hazardous air pollutants. The database includes estimates of annual air pollutant emissions from point sources throughout the United States. The NEI database is based on emission inventories compiled by state and local environmental agencies, supplemented for electricity-generating units in recent years with continuous emission monitoring data. Emission data are reported for CO, SO_2, and NO_x for both time periods. PM emission data are reported for 1987-1989, while both PM_{10} and $PM_{2.5}$ emissions are reported for 1996-1998. This latter period also includes VOC emission data. Comparisons between the two periods are made for the common pollutants, CO, SO_2, and NO_x, as well as PM in 1987-1989 versus PM_{10} in 1996-1998, since these should respond in a similar manner.

A calculation similar to that used to determine facility-allowable emissions under the current NSR rules was implemented by comparing the new actual emission value to the average of the previous 2 years[9] and determining whether it exceeds the previous average by the allowable amount. To address this issue, we define a relative emission change for facility i and pollutant j ($REC_{i,j}$), as follows:

$$REC_{i,j}(t) = \frac{E_{i,j}(t) - \left[\dfrac{E_{i,j}(t-1) + E_{i,j}(t-2)}{2}\right]}{E_{Allow,\,j}},$$

where $E_{i,j}(t)$ is the annual emissions (tons) of pollutant j from facility i in year t, and $E_{Allow,\,j}$ is the allowable increase in emissions before NSR is triggered. As in the EIP report, we assign a value of 1 ton below the trigger value for each pollutant:

$$\begin{aligned} E_{Allow,\,j} &= 39 \text{ tons for } SO_2 \text{ and } NO_x \\ &= 24 \text{ tons for PM} \\ &= 99 \text{ tons for CO} \end{aligned}$$

The REC variable thus provides a standardized measure that can be compared across facilities and pollutants. Emission decreases result in a negative REC value while increases in emissions result in a positive value of the REC. When the REC exceeds 1.0, this indicates an emission increase that should (or at least could) trigger NSR if this increase were associated with an

[9]As pointed out in Chapter 2, firms can use a different time period to calculate the baseline, if they can demonstrate that this alternative period was more representative of normal operations. However, since the prior 2-year period is the default period for the baseline calculation, it is used as the basis for calculation in this analysis.

applicable plant modification. We examined the distributions of REC (1989) and REC (1998) with the hypothesis that some clumping or truncation of the data below a value of 1.0 should be evident if facilities were increasing emissions at the maximum amount allowable without triggering NSR. As shown in Figures 4-1–4-8, where the empirical cumulative distribution functions (CDFs) are plotted, no such clumping is evident. Each figure includes the CDF plot for –3 < REC < 5 to illustrate nearly the full range of REC values, along with a blow-up of the region of the relative emission change between 0.2 and 2.0, to look more closely at the distribution at or below REC = 1.0. The plots indicate that some degree of aggregation is evident at a REC value of zero, since many firms undertake no change in emissions over the 3-year periods; however, the curves are otherwise smooth, with no evidence of truncation at or below REC = 1.0.

Also, we explored whether there was any change in the distribution of REC (1998) values between 1989 and 1998. This analysis is summarized in Table 4-3.

As indicated, a large sample of emission records is available, ranging from 4,957 observations of SO_2 in 1989 to 20,223 observations of PM_{10} in 1998. In all cases, the fraction of facilities reporting increases in emissions decreased from 1989 to 1998. Mean values of $REC_{i,j}(t)$ values decreased as well for all pollutants from 1989 to 1998, as did their standard deviations (substantially for CO and SO_2, only marginally for PM and NO_x). In all cases, the fraction of $REC_{i,j}(t)$ values greater than 1.0 is lower in 1998 as compared with 1989. For the four pollutants, the fraction exceeding 1.0 in 1998 is reduced by a factor ranging from 2 to 6 as compared with 1989 (e.g., for SO_2, the fraction above 1.0 decreases from 0.331 to 0.140, while for PM it decreases from 0.061 to 0.010). This result, consistent with the reduced means and standard deviations apparent in 1998 versus 1989, indicates that a smaller fraction of facilities implemented actual emission increases (of the magnitude associated with the current NSR rule) in 1998 as compared with 1989. Likewise, the conditional probability that the $REC_{i,j}(t)$ value is greater than 1.0, given that it is greater than zero (next to last row of Table 4-3), is lower in all cases in 1998 as compared with 1989. As indicated in the last row of Table 4-3, the ratio of the probability of exceeding a $REC_{i,j}(t) = 1$ for those who had emission increases, decreases by a factor ranging from 2.4 to 5.6.

This analysis is illustrative of statistical evaluations that can be applied to large datasets. The analysis shows that only a small percentage of facilities report emission increases in 1989 or 1998, relative to their previous respective 2-year periods. Furthermore, the results suggest no clumping or truncation at or below 1.0 that would be suggestive of behavior by firms to undertake modifications that increase emissions, but by amounts that are constrained by NSR limitations. There is, however, a significant drop

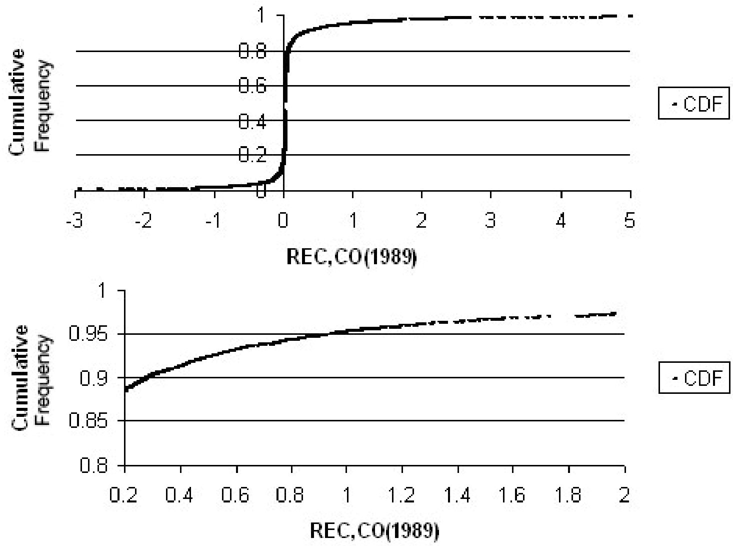

FIGURE 4-1 Relative emission change (REC) for carbon monoxide (CO) for the period 1987-1989. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

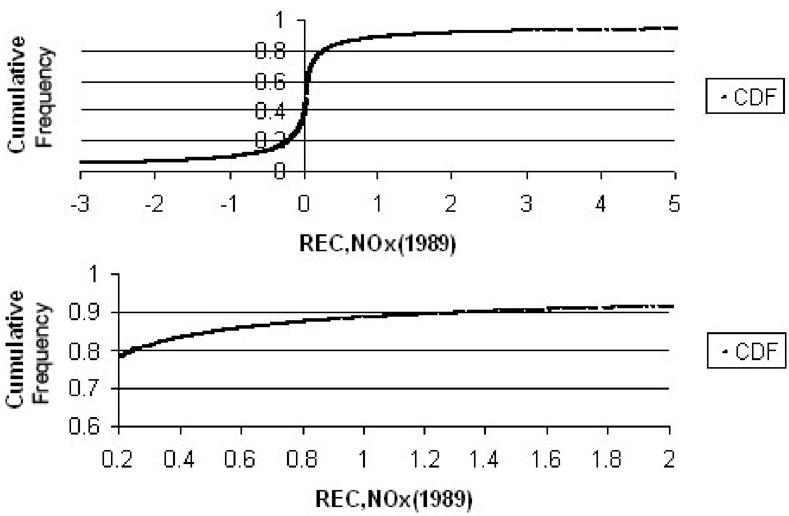

FIGURE 4-2 Relative emission change (REC) for nitrogen oxide (NO_x) for the period 1987-1989. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

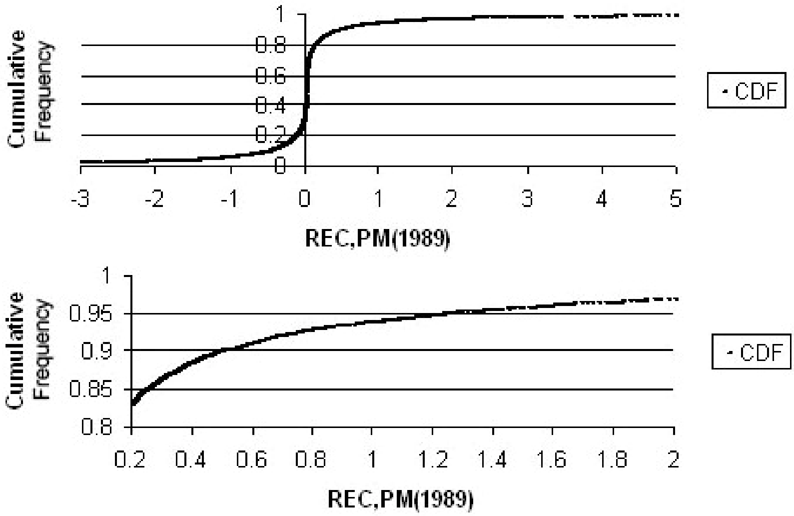

FIGURE 4-3 Relative emission change (REC) for particulate matter (PM) for the period 1987-1989. Cumulative distribution functions (CDFs) are shown for –3 ≤ REC ≤ 5 and a blow-up of the region of the REC between 0.2 and 2.0.

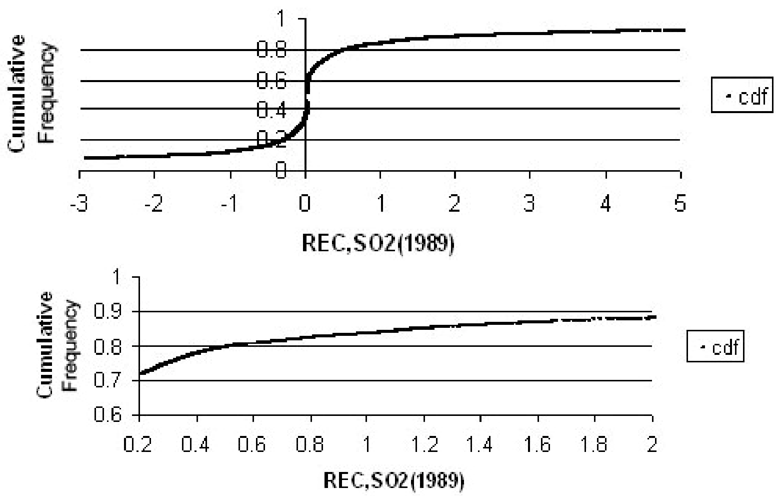

FIGURE 4-4 Relative emission change (REC) for sulfur dioxide (SO_2) for the period 1987-1989. Cumulative distribution functions (CDFs) are shown for –3 ≤ REC ≤ 5 and a blow-up of the region of the REC between 0.2 and 2.0.

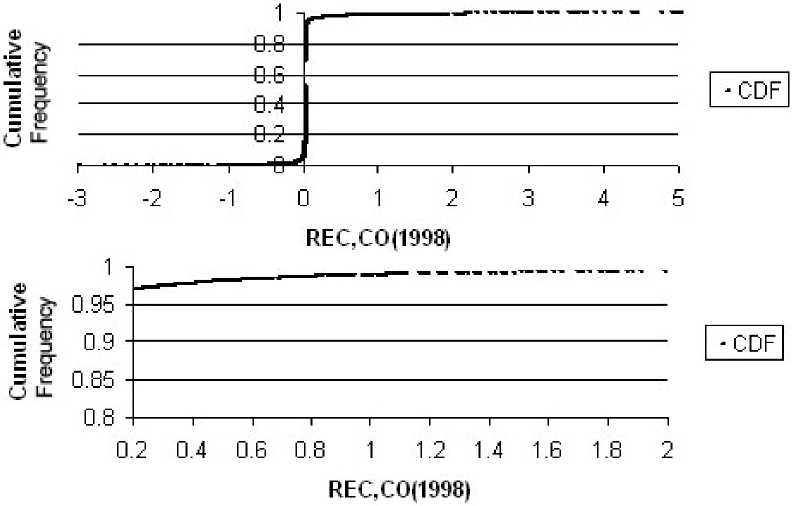

FIGURE 4-5 Relative emission change (REC) for carbon monoxide (CO) for the period 1996-1998. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

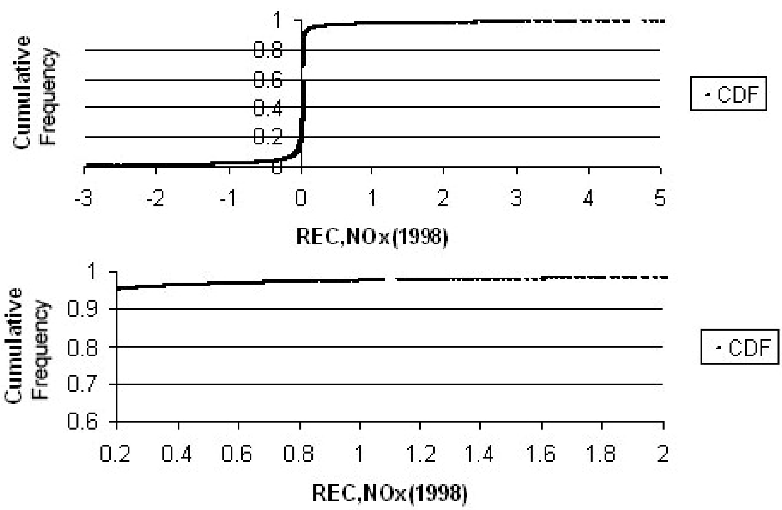

FIGURE 4-6 Relative emission change (REC) for nitrogen oxides (NO_x) for the period 1996-1998. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

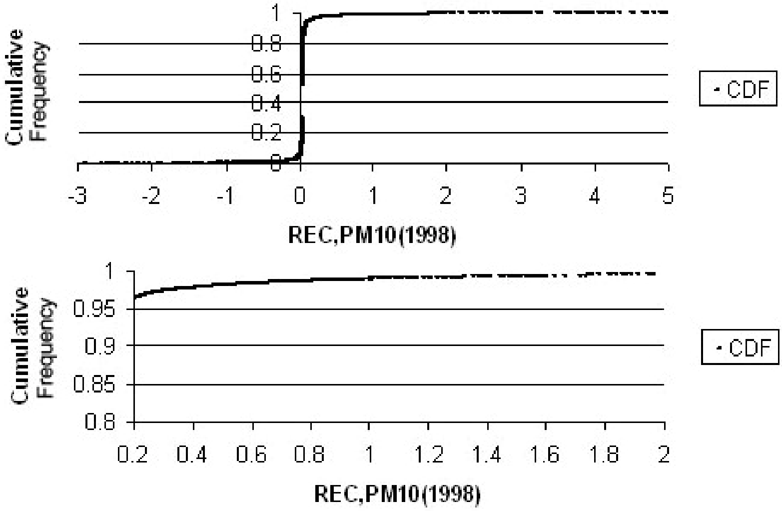

FIGURE 4-7 Relative emission change (REC) for particulate matter with an aerodynamic diameter less than 10 μm (PM_{10}) for the period 1996-1998. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

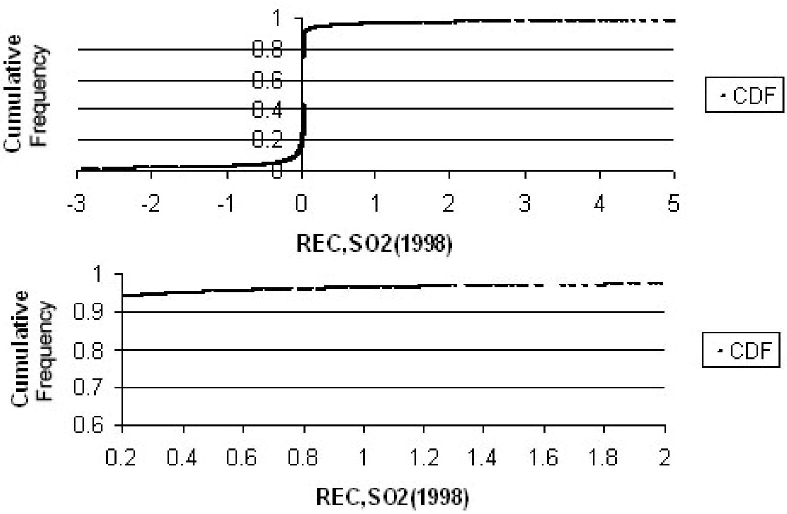

FIGURE 4-8 Relative emission change (REC) for sulfur dioxide (SO_2) for the period 1996-1998. Cumulative distribution functions (CDFs) are shown for $-3 \leq REC \leq 5$ and a blow-up of the region of the REC between 0.2 and 2.0.

TABLE 4-3 Statistical Summary of $REC_{i,j}(t)$ Values

	CO		PM	PM_{10}	SO_2		NO_x	
t =	1989	1998	1989	1998	1989	1998	1989	1998
N (number of plants)	5,628	17,286	6,360	20,223	4,957	13,220	6,100	18,635
Mean	0.304	0.07	–0.0576	–0.088	1.934	0.778	0.895	–0.118
Std. Dev.	5.431	1.819	6.589	6.21	87	31.68	15.4	13.85
Fraction > 0	0.492	0.309	0.517	0.477	0.489	0.258	0.48	0.316
Fraction > 1	0.046	0.0104	0.061	0.01	0.162	0.0362	0.113	0.0246
Prob (>1)/Prob(>0)	0.094	0.0337	0.118	0.021	0.331	0.14	0.235	0.0778
Ratio (1989:1998) of Prob (>1)/Prob (>0)	2.79		5.62		2.36		3.02	

in relative emission increases from 1989 to 1998. Inferences regarding possible implications for NSR enforcement would require information on those facilities undertaking modifications potentially subject to the NSR rules during these periods. Before such an inference could be made, however, other factors that changed during this period (e.g., economic conditions or the stringency of other regulations) would need to be considered. Furthermore, as discussed in Chapter 5, a more complete evaluation would consider more-recent time periods and differences between states.

5

Econometric Analysis

INTRODUCTION

This chapter explores the possibility of using econometric analysis to measure the effects of the New Source Review (NSR) rule changes on a variety of outcome measures. As explained in Chapter 4, the best available approach (given data constraints) would be a reduced-form estimation, in which a facility's outcome measure (Y) is related to an indicator of the type of NSR rules faced by the facility (X) and to other explanatory variables (Z) that could affect the outcome (as in Equation 4-1):

$$Y_i = a + bX_i + cZ_i + e_i.$$

Chapter 4 noted that a reduced-form analysis could identify the variation in NSR regulation in three different ways. A time-series approach would focus on variation in Y for the same facility before and after the NSR rule changes. A cross-section approach would focus on variation in Y across facilities in different states when some of the states had implemented the NSR rule changes and others had not. A difference-in-differences approach would combine the two others, first calculating the changes in Y for each facility over time, and then comparing those changes across facilities that were affected by the NSR rule changes at different times. A comprehensive analysis could include all three approaches, testing for consistency across the different sets of results. As with any econometric analysis, it is important to include a comprehensive set of Z variables to control for other factors that might affect Y. In the case at hand, we are looking at the impact of the 2002 and 2003 changes in the U.S. Environmental Protection Agency (EPA) NSR process, which made it easier for a facility to renovate without triggering NSR. Changing the stringency of NSR requirements could have offsetting effects on overall pollution. If a firm chooses to go through NSR permitting despite having to face the stringent rules, stricter NSR requirements would generate greater emission reductions at the facility. Some firms trying to avoid NSR requirements would also reduce emissions by undertaking other pollution-control projects to avoid an increase in overall emissions or by accepting enforceable limits on facility emissions in the form of a "synthetic minor"[1] designation. If a firm facing less strict regulations decides to invest in new equipment that results in a lower emission rate than does its existing equipment (although not as low as NSR might require), the less strict NSR rules could actually decrease emissions. NSR could thus affect both the decision of whether to adopt a new investment project and the final characteristics of the project, and it might cause alterations in other areas of a facility either to meet NSR requirements or to avoid NSR entirely. As outlined below, the recent and ongoing nature of the NSR rule changes, combined with the multiyear lags in the availability of outcome measures, make it impossible at this point to analyze the impact of the NSR rule changes on investment projects and overall emissions—the data are simply not yet available.

IDENTIFYING VARIATIONS IN POLICY

Variations in Policy Timing

To do any econometric analysis, we must be able to measure when and where the NSR rule changes became effective so that we can properly define the X variable in Equation 4-1 for any given facility-year observation. Under the U.S. federal system of environmental regulation, much of the regulatory activity is conducted by state agencies and is subject to federal oversight. In the case of air-pollution regulation, states develop state implementation plans (SIPs) designed to meet federal air-quality standards and conform to various federal requirements. Existing SIPs have been approved by EPA, and changes in a SIP must also be approved by EPA. Thus, if a state's SIP includes an NSR program that applies to a particular facility, the state has to propose a revision to the NSR program, and EPA has to approve the revision before the NSR rule changes become effective for that facility. EPA gave such states until January 2006 to submit revised SIPs that incorporate the new

[1]As discussed in Chapter 2, a source may reduce its potential to emit by agreeing to a legally binding limit on its emissions. If the source agrees to a limit that reduces its potential to emit below the coverage thresholds, it is no longer a major emitting facility and is exempt from the program.

NSR rules. A few states have already revised their SIPs and submitted them to EPA for approval (see Chapter 2), although at this writing none of the revised SIPs has been formally approved by EPA, so at least in 2005 none of the facilities in these states has been covered by the NSR rule changes.

In contrast, facilities in states without an approved NSR program are subject to NSR rules at the federal level, so changes in the NSR rules for these facilities could be implemented directly by EPA. For such states, EPA made the NSR rule changes effective on March 3, 2003. All areas in nonattainment of the National Ambient Air Quality Standards (NAAQS) in which Part D applies have incorporated the Part D NSR program into their SIPs. A total of 13 states (entire or part) chose not to include a prevention of significant deterioration (PSD) rule in their SIPs, so make up the "implemented" group, where the NSR rule changes took effect first, in 2003.

Table 5-1 shows the list of states in the "implemented" and "nonimplemented" groups. The 2002 NSR revisions took effect on March 3, 2003, for states in the implemented group. States in the nonimplemented group will be subject to the revisions once they submit and EPA approves a revised SIP incorporating the NSR rule changes If a state opposing the NSR changes chooses not to submit such a SIP revision, EPA would have to decide whether to make the SIP changes themselves, which might involve further delay. A few of the states in the nonimplemented group indicated that they have already submitted revised SIPs to EPA, which may result in their NSR changes being approved earlier than those of other states in the nonimplemented group (but still at least 3 years after the implemented group).

One potential measurement difficulty for this analysis is related to identifying the "true" effective date of the regulations. Two sets of NSR rule changes were made final by EPA: in December 2002, changing the calculations that determine whether a given modification results in an important emission increase that will trigger NSR; and in October 2003, exempting routine maintenance, repair, and replacement projects from NSR. The latter set of rule changes are referred to as the equipment replacement provision

TABLE 5-1 Timing of NSR Rule Changes

Implemented group (March 3, 2003; only NAAQS attainment areas)	AZ[a], CA[a], HI, IL, MA, MI, MN, NV[a], NJ, NY, PA[a], SD, WA
Nonimplemented group (no sooner than 2005-2006)	AL, AK[b], AR, CO, CT, DE, DC, FL, GA, ID[b], IN[b], IA[b], KS, KY[b], LA, ME, MD, MS, MO, MT, NE, NH, NM, NC, ND, OH[b], OK, OR, RI, SC, TN, TX, UT, VT, VA, WV, WI, WY

[a]Partial coverage of state PSD areas in SIP.
[b]Nonimplemented group states that have already submitted SIP revisions to EPA.

(ERP). The rule changes have been the subject of court challenges and of opposition from some state regulatory agencies. Opponents to the ERP obtained a stay through the courts, so it never went into effect, and has been invalidated. Parts of the 2002 rules were also invalidated by the courts, so those rules are only partly in effect in a few states. Some time may elapse between the initial planning of an investment project and permit approval, so a firm could begin planning for a project, anticipating one set of rules, but face a different set of rules when the permit is finally decided. That uncertainty will tend to make firms conservative in responding to regulatory changes especially when there is a chance that the changes could be reversed. The possibility of reversal makes it difficult to be certain when the rule changes will start to affect investment decisions and thus more difficult to measure the effects of the rule changes. Uncertainty about other regulatory changes could also influence the impact of NSR on investment, including possible changes in NAAQS for ozone and particulate matter, as well as regional regulations, such as the Clean Air Interstate Rule (CAIR) and the proposed mercury rule. Because only the 2002 NSR rules have been implemented, the difficulty of identifying the effects of the two rule changes separately does not arise.

A second measurement difficulty is driven by the "forward-looking" nature of a firm's investment decisions. An investment project at a facility is likely to affect its production process for many years, so the decision to undertake a particular investment today may depend on the firm's expectations about regulatory constraints in the future. To the extent that NSR rules are expected to become less strict in the next year or two, firms may postpone investments until the NSR rule changes take effect. Such postponement could lead to a bunching of investment in the first few years after the rule changes, and the short-run response of investment could be considerably larger than the long-run response. Econometrically, that effect might be inferred if investment fell immediately before the NSR rule changes, rose sharply immediately after the changes, and then returned to near previous levels a few years after the changes. Such a measurement difficulty suggests the need to collect several years of outcome data and to examine closely the time pattern of outcome changes relative to policy changes.

Because the NSR rule changes affected some states in 2003 and other states are not affected until 2006 or later, we have some variation in policy timing to support a reduced-form model: seeing similar changes in outcomes (such as investment, pollution, and efficiency) in the nonimplemented states a few years after they occurred in the implemented states. Of course, other things may affect the timing, but the predictable timing of the policy change, combined with the variation across states, will help. We also get differences in policy timing within states based on the differences between NAAQS attainment and nonattainment areas in the implemented states. We would obtain even stronger data for analysis if EPA were to allow some states to retain the prior NSR rules, which would result in long-run differences in investment and pollution outcomes across states. Note also that if the legal challenges to the NSR changes are successful, all facilities in all states will revert to the previous NSR policies, providing yet another policy change for an econometric analysis to work with (although less long-run effect to measure in the future).

Variations in Policy Stringency

So far we have discussed the NSR rule changes as though they had uniform effects on all facilities. The primary effect of the changes was to exempt from the need for an NSR permit some investment projects that would have required a permit under the prerevision rules. However, the stringency of an NSR permit can differ from one facility to another. First, NSR permit stringency may depend on facility location. Facilities in NAAQS nonattainment areas need to meet the lowest achievable emission rate (LAER), which can be more stringent than the best available control technology (BACT) required of facilities in attainment areas, along with other requirements (see Chapter 2). Second, the details of what is required under LAER and BACT may differ across facilities depending on the interpretation of those standards by the regulatory official responsible for approving the NSR permit. Certain states may tend to have more stringent interpretations of these requirements than others. Finally, the NSR permit review process could differ across states in speed and predictability, with slow or uncertain permit approval in some states serving as a major discouragement to investment activity. The importance of delaying the investment process could be especially important for manufacturing facilities, where firms are attempting to respond to rapidly changing business conditions.

Even if the NSR permit standards are the same for two facilities, the effect of the rule changes at each facility will depend on the stringency of any "fallback" permit requirements that the facility faces if it does not need an NSR permit. Depending on local air quality and state regulatory stringency, the application process for a minor permit might be about as stringent as that for an NSR permit or substantially less stringent. Massachusetts, Michigan, and Virginia indicated that their minor-permit programs require BACT in some circumstances, so the NSR rule changes might have less effect for them. Most states indicated only that they had some sort of minor-permit program in addition to NSR (e.g., Zervas 2005), so there does not seem to be enough information available at this time to characterize the stringency of state minor-permit programs. More detailed information about state minor-permit programs was provided by state regulatory agencies—suggesting that a more comprehensive database of state permit data could be developed and collecting such data is in fact one of the committee's recommendations mentioned later in this chapter.

The existence of different NSR effects among states adds uncertainty to an econometric analysis and makes it more difficult to measure any NSR effect. Suppose that NSR had a big effect in half the states in the implemented group and no effect in the other implemented-group states. The average effect might not be statistically significant, because the no-effect states dilute the effect of the others (the high variance in outcomes in the implemented group would reduce the significance of any difference in average outcomes between the implemented and nonimplemented groups). If we could add variables identifying the no-effect states to the analysis, we could estimate the effect of NSR separately for the high-effect states and improve the overall precision of our estimate of NSR effect and thus we could raise the likelihood of finding statistical significance.

One indirect indicator of a state's desired level of stringency in NSR permits could come from the legal battles surrounding EPA's NSR changes. Fourteen states and the District of Columbia brought suit against EPA to stop the rule changes. Those states arguably prefer more stringent NSR rules, so their permit writers would be expected to be stricter in interpreting the NSR requirements. But nine states supported the EPA's legal position on the NSR rule changes, so permit writers in those states might be expected to be less stringent in their interpretations of NSR. That argument presumes that the variation among states in the policies preferred by state attorneys general who bring the lawsuits is similar to the variation in the policies preferred by the state regulatory-agency staff members who write the permits. Table 5-2 shows the breakdown of the implemented and nonimplemented groups of states by their position on the NSR rule changes. Note that of the implemented states (where the rule changes were implemented first) only South Dakota supported the NSR rule changes.

TABLE 5-2 Legal Challenges to 2002 NSR Rule Changes by States

Challenged NSR Changes	No Position	Supported NSR Changes
Fully and partially implemented group		
CA[a], IL, MA, NJ, NY, PA[a]	AZ[a], HI, MI, MN, NV[a], WA	SD
Nonimplemented group		
CT, DE, ME, MD, NH, RI, VT, WI, DC	AL, AR, CO, FL, GA, IA, ID, KY, LA, MO, MS, MT, NC, NM, OH, OK, OR, TN, TX, WV, WY	AK, IN, KS, ND, NE, SC, UT, VA

[a]Partial implementation of state PSD areas in SIP.

Policy Perception by Industrial Firms

As discussed above, it will be possible to identify when the NSR rule changes became legally valid in different areas, but it may take some time before the affected firms change their investment decisions. Information about the actual timing of the changes should be supplemented by information about how quickly firms recognized those changes. Several approaches may provide useful results to researchers:

- Discussions about the NSR rule changes with decision makers at regulated firms to identify when investment behaviors changed.
- Surveys of firms to identify when they recognized the NSR rule changes, perhaps using a series of surveys over the time period that the new NSR rules are being adopted in different states, to see whether firms' perceptions of the date of change correspond to the actual differences across states in rules change.
- Discussions with state regulators to confirm information obtained from the respondents at firms. This could also involve collecting information across states to confirm the characterization of different states as early and late adopters of the new NSR rules.
- Identification of efforts made in each state to inform affected firms of the change, helping to explain why firms in different states responded more or less quickly to the NSR rules change.

Permit Data

It may seem natural to use NSR permit data to identify changes in outcomes related to the NSR rule changes. The permits include information on allowable emissions and required emission reductions. Such permit data have been used in the past (NESCAUM 2004; FLDEP 2005) to predict increases in allowable emissions if less stringent NSR requirements were adopted. These calculations assume that the same set of investment projects would be getting permits and that they would take advantage of any weakening of NSR requirement to increase their emissions as much as possible. As noted earlier, changes in NSR rules could encourage additional investment in new productive equipment that may be cleaner than the older equipment it replaces. It is possible that enough new, emission-reducing investments would occur that overall emissions would be reduced even if a few investment projects would be able to take advantage of the weaker NSR rules to proceed with projects that might entail increases in emissions, or at least smaller emission reductions than they would have needed under the prerevision NSR rules.

More useful for analysis would be information about minor state construction permits that would still be required of projects that no longer needed NSR permits. If no additional investment activity were needed because of the change in NSR rules, we might see a small increase in minor permits as fewer projects required NSR permits. A substantial encouragement of new investment activity (as anticipated by proponents of the NSR rule changes) would be seen in an increase in minor permits that was considerably larger than the decrease in NSR permits.

The econometric analysis would compare the number and type of permits required in each state, both implemented and nonimplemented, in each year. The analysis would control for other factors that might affect firms' investment decisions among states or over time (such as changes in economic conditions in the states or nationally). EPA has collected some data on NSR permits, and some states maintain permit databases that could support econometric analyses of their minor permits. The analysis would look for changes in the total number of permits approved each year (NSR and minor) around the time of the rule changes and changes in the relative numbers of NSR and minor permits.

The major hindrance to doing such an analysis is the limited amount of permit data available, especially in the minor state permit databases, as noted in Chapter 3. Table 5-3 shows information from the existing EPA dataset of NSR permit data for 1997-2002. Even over that 6-year period, most states have relatively few NSR permits issued. Many states keep their permit data in paper form, and the final permit document is sometimes accessible electronically as a portable document format (PDF) or word-processing file. State permit databases tend to be idiosyncratic, having been developed by state regulatory agencies with no particular effort to be compatible with other states' databases. Of the 13 states in the implemented group, only four were clearly described as having electronic permit data. Of the 38 states (and the District of Columbia) in the nonimplemented group, 18 reported some electronic permit data. An example of a compatible database in use is the TEMPO system (an ORACLE database, developed by AMS, that combines all information about a facility with permit, inspection, and compliance data). The TEMPO system is being used by Kentucky, Maryland, and New Mexico, all in the nonimplemented group, although some of the states began using it only recently.

TABLE 5-3 Permit Data by State (1997-2002)

	Number of NSR Permits			
	Total	Electricity-generating Sector	Manufacturing Sectors	State Permit Data Availability[a]
Implemented states				
AZ	26	26	0	—
CA	52	31	18	Paper records[b]
HI	13	13	0	Paper/document
IL	195	117	78	Electronic (ORACLE, 1972+)
MA	15	15	0	Paper/document
MI	190	109	54	Electronic (DOS)
MN	182	19	61	—
NJ	62	62	0	Electronic (ORACLE)
NV	8	8	0	—
NY	36	32	4	Electronic (AFS)
PA	115	60	22	—
SD	2	2	0	—
WA	22	19	3	Paper/document[b]
Nonimplemented states				
AK	169	6	1	Paper/document
AL	478	196	186	Electronic (new)
AR	229	83	101	Electronic
CO	82	70	0	Paper, electronic (FoxPro)
CT	22	22	0	Paper/electronic
DC	0	0	0	—
DE	14	8	6	Paper
FL	443	325	118	Paper/document
GA	123	67	56	Paper
IA	80	27	53	Electronic (1995+)
ID	2	2	0	—
IN	167	78	89	Electronic (ORACLE)
KS	18	3	15	Electronic (ISTEPS, 1997+)
KY	142	43	99	Electronic (Tempo)
LA	348	79	245	Paper
MD	9	5	4	Electronic (Tempo, old-FoxPro)
ME	31	31	0	Paper/document
MO	99	69	30	Paper
MS	140	88	49	Electronic (2000+)
MT	23	5	18	Paper/electronic
NC	226	103	114	Paper[b]
ND	5	0	5	Electronic (Access)
NE	37	33	4	Electronic (IIS)
NH	0	0	0	Electronic (FoxPro,ORACLE)
NM	51	51	0	Electronic (Tempo, 1998+)
OH	117	37	80	Electronic
OK	90	90	0	Electronic (Access)
OR	15	4	11	Paper

TABLE 5-3 Continued

	Number of NSR Permits			
	Total	Electricity-generating Sector	Manufacturing Sectors	State Permit Data Availability[a]
RI	7	7	0	Paper/document
SC	100	28	72	Electronic
TN	101	12	89	—
TX	250	153	76	—
UT	20	11	6	Electronic (Access, ORACLE)
VA	198	120	48	Electronic (ORACLE)
VT	1	0	1	—
WI	302	102	200	Electronic (ORACLE)
WV	19	11	8	Paper/document
WY	287	23	0	—
Total permits:	5,363	2,505 (47%)	2,024 (38%)	

[a]— = No response to State and Territorial Air Pollution Program Administrators' survey.
[b]County or district responded, but state did not respond.

NOTE: For paper, permit data available as paper files; for paper/document, permit data may be available in electronic text (PDF or word processor); for electronic, permit data available in database (format and years, where available).

Outcome Data

The final data that will be discussed are those that represent the various outcomes, providing the Y variable for estimating Equation 4-1.[2] The initial outcomes to be measured are the investment decisions made by the facilities. The benefits claimed for the NSR rule changes are connected to encouraging investment-generating sufficient investment in new capital equipment, which is cleaner and more efficient than the equipment being replaced, increases economic and energy efficiency, and decreases overall emissions. The discussion of the structural and behavioral econometric model in Chapter 4 noted that it would be difficult to get data on the success or failure of individual

[2]We do not discuss here the various control variables (Z) that might be included in the estimations—controlling for factors besides the change in NSR rules (X) that might affect the outcome variables (Y). Different outcome variables will require different control variables; for example, the other determinants of investment spending at a plant might include the overall demand for the industry's output, tax incentives for investment at the plant, and the owning firm's profitability. Determinants of a plant's emissions might include the age of its capital stock and other regulatory pressures faced by the plant (inspections and other enforcement activity). Developing detailed models for each outcome variable is a large part of the effort needed for the econometric analysis being recommended here.

investment projects, especially if we wished to include project proposals that were ruled out by a facility before a permit request was submitted to regulators. However, there are data on overall capital expenditures related to new plant and structures, which may allow identification of any large swings in investment behavior that happened around the time of the NSR rule changes.

Several other outcomes were identified as part of this committee's charge: emissions of pollutants, effects on human health, investments in pollution-control and -prevention technologies, and efficiency of facility operations. The discussion below focuses on available sources of data for measuring those outcomes at the facility level. Facility-level data are not always available, but because the implemented group consists of facilities in NAAQS attainment areas in 13 states, published aggregate data at the national or even state level do not provide sufficient detail to distinguish between implemented and nonimplemented facilities. Having facility-level data also allows the analysis to include controls for a facility's industry and size, which can improve the precision of the estimates. Also, the facility-level data can be linked to allow the analysis of several outcomes simultaneously, for example, seeing whether a facility that substantially increased its spending on new capital equipment after the rule changes also achieved increased efficiency or reduced emissions in later years.

It is possible to use models of pollution effects and atmospheric chemistry to calculate the impact of emissions from a facility on the ambient air quality in surrounding areas (see Chapter 7). Having connected facility emissions to changes in ambient air quality, one could add data on population concentrations to calculate the expected health effects from changes in pollution emissions. Such models are discussed in Chapter 7. These models do not involve econometric analysis of a connection between the NSR rule changes and health outcome data. Instead, the results of past studies that identified a connection between ambient air quality and health outcomes would be combined with (noneconometric) atmospheric models of pollution flow to quantify the health effects. Hence, any facility-level measure of the effects of the NSR rule changes on human health would be derived directly from changes in facility-level emissions. If emissions increased, we would expect air quality to worsen and adverse health effects to increase. Complications arise in the assessment if emissions of some facilities increase and emissions of other facilities decrease. Then the details of the emission-health connection (tied to such factors as the relative population densities near the emission-increasing and emission-decreasing facilities) would be used to determine the overall net effect on health.

Table 5-4 provides information on available data sources to measure the outcome variables for manufacturing facilities. Many of the data are collected by the U.S. Census Bureau. The cornerstones of this data collection

TABLE 5-4 Types of Outcome Data for Manufacturing Sector

Outcome	Measure	Source
Investments	New capital spending ($)	Census ASM, CM
Pollutant emissions	Amount emitted (tons/year)	EPA National Emissions Inventory, Continuous Emissions Monitoring System
Pollution control	New PACE capital ($)	Census PACE
Technology use	Abatement technology	EPA Aerometric Information Retrieval System Facility Subsystem
Energy efficiency	Output:energy ratio	Census ASM, CM
Materials efficiency	Output:materials ratio	Census ASM, CM
Labor productivity	Output:workers ratio	Census ASM, CM
Total factor productivity	Output:inputs ratio	Census ASM, CM

are the Annual Survey of Manufactures (ASM) and Census of Manufactures (CM) programs. The ASM collects a basic set of data each year from about 55,000 manufacturing facilities. The sample is size-weighted so that very large facilities are included every year, and smaller facilities are rotated in and out of the sample every 5 years. The CM collects a broader range of data on all manufacturing facilities but is conducted only every 5 years (for the purpose of this study, the relevant years would be 2002 and 2007). In addition, the Census Bureau conducts special surveys to collect detailed information on other topics. Most relevant to our project is the Pollution Abatement Costs and Expenditures (PACE) survey, which collects annual data on capital expenditures and operating costs for pollution abatement with some degree of detail that varies among different types of expenditures and pollution media.

The outcome measures available from Census Bureau data include investment spending, pollution abatement spending, and various efficiency measures. Data on investment spending (new capital expenditures) are broken down into equipment and structure investment. These data can be aggregated to generate a measure of a facility's capital stock for large facilities with continuous ASM data. The ratio of annual investment spending to total capital stock shows what fraction of the capital stock is being replaced at a facility each year and can be used to test whether the replacement rate increases or decreases after the NSR rule changes.

The PACE survey data include information on the amount of new investment in air-pollution abatement capital. These data allow tests for increases or decreases in the amount of air-pollution abatement investment after the NSR rules changed. Some limitations of the PACE data may affect the analysis. First, and most seriously, the PACE survey was not conducted during the 2000-2004 period. (The PACE survey was conducted annually from 1973 to 1994; then it was halted for financial reasons. A revised version of the survey was done for 1999, and annual data collection has been resumed, starting with data for 2005.) This makes it difficult to benchmark the pollution abatement investment to the pre-rule-change period and limits the number of observations on the implemented group (losing data for 2003 and 2004). If the PACE data collection resumes on schedule with the collection of data for 2005, there will be 2 years (2005 and 2006) of differences between nonimplemented and implemented groups for analysis followed by a transition (in 2007 or later) of the nonimplemented states into the implemented group—possibly in different years in different states.

The Census Bureau data are particularly helpful in calculating various efficiency measures, including energy efficiency, the focus of most of the discussion of efficiency in other chapters of this report. The energy efficiency of manufacturing firms would be measured as the quantity of fuels and electric energy consumed divided by the real production at the facility. An efficiency index related to life-cycle pollution-prevention outcomes could be calculated in terms of material efficiency as real material input per unit of real production at the facility. The Census Bureau data also include sufficient information to calculate more general efficiency measures, such as labor productivity (real output per production worker hour) or total factor productivity (real output per unit of total input). The measure of total factor productivity, for which total input is a weighted average of all inputs (including capital, materials, and labor) provides an overall indicator of the effect of the NSR rule changes on the efficiency of production and measure of the overall costs (or benefits) of the rule changes.[3]

Through the efforts of the Census Bureau's Center for Economic Studies, the ASM and CM data have been linked at the facility level in the Longitudinal Research Database, as described in McGuckin and Pascoe (1988). The census data also include facility-level links to the PACE survey data, and this link allows investment in pollution-control equipment to be included in the analyses. These data have been used by numerous researchers in recent years to measure the effects of environmental regulatory pressures on a variety of business outcomes (including Levinson [1996] and Becker and Henderson [2000], cited in Chapter 4).

The Census Bureau facility-level data are confidential and are available only to researchers on approved projects and accessible only through the network of Census Research Data Centers (RDCs). The cost of running the network requires that projects pay laboratory fees to an RDC. Considerable time is needed to prepare a research proposal and get approval, in addition

[3]Gray (1987) discusses the use of total factor productivity to measure the net benefits (or costs) of regulatory changes.

to the efforts required to merge the required data and carry out the analyses. Any research project that would use the Census Bureau data would therefore have to be appropriately budgeted with respect to both time and money. One possibility is to incorporate the research into an existing project if there is sufficient lead time and researcher interest.

Similar economic production data on individual electricity-generating plants are collected by the U.S. Energy Information Administration (EIA). Access to the EIA data is easier to arrange than access to the Census Bureau data because much of the electricity-generating sector has been regulated as a public utility, and investment and production have become matters of public record as part of rate-setting deliberations by state utility boards. Because of the public nature of the EIA data, many researchers have used databases compiled at the facility level to analyze the effects of environmental regulations on production, investment, and productivity at electricity-generating facilities (Maloney and Brady [1988] and Nelson et al. [1993], as cited in Chapter 4).

Information on economic outcome measures for nonmanufacturing, nonutility facilities[4] is much less complete. The Census Bureau collects some data on nonmanufacturing industries in its Economic Census every 5 years, but data on most industries outside manufacturing are not collected in the intervening years. That would make it relatively difficult to perform econometric analyses aimed at identifying differences between facilities in the implemented and nonimplemented groups during the period 2003-2006. Fortunately, the NSR permit numbers presented in Table 5-3 (and discussed in more detail in Chapter 3) show that 85% of existing NSR permit activity occurs at either electricity-generating facilities or manufacturing facilities, so this data limitation should not be a serious impediment in measuring the overall effects of the NSR rule changes.

Emission data at the facility level is collected by EPA in the National Emissions Inventory (NEI). The NEI data are collected in great detail on both large and small sources of pollution every 3 years (1999, 2002), but some of the data focus on the larger facilities, updated annually. In addition to the NEI data-collection effort, emission data in recent years on some major sources (notably large electricity-generating facilities) are collected in the Continuous Emissions Monitoring System and should provide especially accurate emission measures. Data on the pollution-abatement equipment in place at a facility are also available in EPA databases, such as the Aerometric Information Retrieval System Facility Subsystem database.

Those outcome measures are not immediately available, so it would be some time before analysis could begin. The Census Bureau datasets take about 2-3 years to become available to researchers: information from the

[4]SIC 13—oil and gas extraction—has the largest number of NSR permits in this area.

2002 Economic Census is being released in 2004-2006; the most recent ASM available at this writing (in late 2005) is from 2003, the first year in which changes might be observed. EPA's NEI data take a similar period before being released.[5] Because the NSR rule changes will not affect facilities in the nonimplemented group of states until 2007, it seems reasonable to project that a complete analysis will be feasible some time in 2009 or 2010.

GAO (2003) noted EPA's lack of data for measuring the emission effects of the NSR rule changes. The report recommended that EPA work with state and local agencies to identify data sources and monitor emissions to better measure impacts on emissions in the future. The report also noted that EPA agreed with the report's recommendations.

UNCERTAINTY AND STATISTICAL POWER

The committee's charge included providing estimates of the amount of uncertainty associated with the estimated effect of the NSR rule changes. One advantage of an econometric model is that it provides both a point estimate of an effect and a measure of its statistical precision. The precision will depend on the number of data points in the sample and the variability in the outcome measures across the implemented and nonimplemented groups, which results in a type of model uncertainty that must be considered. The underlying Census Bureau and EPA databases contain information on thousands of facilities, but considerable data variability may not be covered by the explanatory variables (Z) in the model. With many kinds of facilities in the database (which vary by industry and size), some care may also be needed in deciding whether to apply a single set of estimated coefficients to all facilities.

An example of the calculations of sample variability is given in Gray (1993) as part of a discussion of using Census Bureau data to measure the effects of Occupational Safety and Health Administration (OSHA) regulatory activity on investment spending and plant efficiency. That study focused on the costs of complying with new OSHA regulations, increasing capital investment and lowering productivity at the affected plants, but the underlying assumption was similar: some plants are affected by regulatory changes, and others are not. The statistical calculation used is a test for the difference between the means of the affected and unaffected groups:

$$T = (m_a - m_u)/([(s_a/n_a) + (s_u/n_u)]^{1/2}),$$

[5]On the basis of information posted in September 2005 on EPA's Web site, the 2005 NEI data update will receive less effort than usual, so that resources can be focused on a re-engineering of the NEI data-collection process aimed at the 2008 NEI (EPA 2005d). States will still be expected to submit emission data on large sources, but the data will be less standardized by EPA. The 2005 NEI data are projected to be available by December 2006.

where m is the mean, s is the variance, and n is the number of observations in each group. If the test statistic, T, exceeds 2, it is taken as evidence of a statistically significant difference between the means of the two groups[6] and that would indicate that the OSHA regulation had a significant effect on compliance costs as measured by investment spending or productivity levels.

An alternative use of the T calculation is to estimate how precisely a given dataset could distinguish between the means of two groups. Gray (1993) assumed that the variance in each group is equal to S and calculated how large the difference M between the group means would need to be to give a significant T test (at the 95% level):

$$M = 2S\,[(n_a + n_u)/(n_a n_u)]^{1/2}.$$

Estimates of S were obtained from Census Bureau plant-level data by looking at the unexplained variability from econometric models of investment and productivity. The analyses were done in logarithmic form, so S was expressed in terms of percentage variation. Investment was much more variable than productivity across plants: S was 1.5 for investment and 0.2 for productivity. If there were 500 plants in each group, the value of M for investment would be $0.19 = (2)(1.5)[(1{,}000/(500)(500)]^{1/2}$. A significant value of T would be obtained if the investment was 19% greater in affected plants than in unaffected plants; the additional investment would presumably be driven by the added compliance costs of the regulation. For productivity, a significant T would result from affected plants having productivity 2.5% lower than unaffected plants.

Combining the variance information with estimates of the numbers of plants in the affected and unaffected groups, Gray (1993) was able to calculate which of several OSHA standards were likely to have significant effects on compliance costs, given ex ante estimates of the magnitude of compliance costs for each standard. In the case of the NSR rule changes, there is a wider array of outcome variables to consider, but the fundamental nature of the statistical tests is the same: get estimates of the amount of variation in the data for a variable and then see whether the difference between the affected and unaffected plants in their average outcomes exceeds the critical amount of variation for the T test.

We focus our attention here on the same investment and productivity measures as examined in Gray (1993) to use the same estimates of variation in investment and productivity. The change in the calculation comes in the number of plants in the affected and unaffected groups. For the NSR rule

[6]If the true means of the two groups were the same and we drew n_a and n_u observations at random from the two groups, the T statistic as calculated here would exceed 2.0 less than 5% of the time.

changes, the calculation involves the number of plants that are large enough to be affected by the rule changes and their allocation into the two groups (implemented and nonimplemented). Using data provided by EPA on the number of major sources in each state, we calculate a total of 7,890 plants with emissions of any criteria pollutant exceeding 100 tons/year (tpy). (Strictly speaking, only facilities in 28 source categories face a 100-tpy cutoff, and others face a 250-tpy cutoff—but those 28 categories contain nearly all major facilities.) Of those, 1,888 were in the implemented group. We assume that only half the plants (in both groups) would have Census Bureau data available. For investment, we get

$$M = (2)(1.5)([3{,}945/(944)(3001)])^{1/2} = 0.11,$$

so we would need an increase in investment of about 11% to observe a significant difference between affected and unaffected plants (for productivity, the comparable value for a significant difference is 1.5%).

CONCLUSIONS AND RECOMMENDATIONS

The best econometric approach to measure the effects of the NSR rule changes appears to be to estimate a reduced-form model, comparing outcomes (such as investment spending and pollution emissions) across sets of facilities in states that differed in the effective date of the NSR rule changes. The data for such analyses will not become available until some years after the fact, and this will delay analyses. The NSR rule changes began to be implemented in 2003 but will not take effect in most states until 2007 or later. A complete econometric analysis may not be feasible until 2009 or 2010. Furthermore, any such analysis will be subject to measurement error because of concerns about the uncertainty of whether the rule changes will hold up to court challenge and the possibility that anticipation of the rule changes could affect the timing of investment decisions. Diversity among states in the timing and magnitude of the NSR rule changes will help researchers to get a better measurement of the effects of the changes, and this will make possible a reduced-form analysis of the effects of the changes on investment and emissions.

Carrying out such an analysis efficiently will require preparation. First, the committee recommends that data be collected for each state on the date when the NSR rule changes become applicable for facilities in that state in both attainment and nonattainment regions. That will require tracking EPA's approval of revised SIPs. In addition to the precise legal dates, qualitative data need to be collected, through surveys or interviews with firms and regulators, to identify when firms recognize the NSR rule changes and incorporate them into their investment decision making. It would be especially helpful to gather such information continuously beginning soon, so that analysis need not rely solely on retrospective surveys after the NSR rule changes are firmly entrenched (when firms' and regulators' recollections about what they knew and when they knew it may be colored by their knowledge of what eventually happened).

Second, the committee recommends that a suitable database on NSR and minor state permits be collected. Perhaps EPA could work with state agencies to develop a consensus on the information such a database should include facilitating the development of a national permit database and permitting cross-state analyses for the impacts of NSR rule changes as well as analyzing other regulatory activity.

EPA has done some updating of its NSR permit database beyond the initial 1997-1999 data collection and should be encouraged to continue the updating. Although that database cannot provide complete measures of the effects of the NSR rule changes on outcomes, it constitutes a useful description of where NSR-covered activity continues. Much greater effort will be needed to assemble a useful collection of data on minor state permits. States that have not yet developed permit databases of their own could be encouraged to adopt a common database layout or at least to design their database to make it easy to export permit information to a compatible national permit database. States that do have permit databases should develop conversion programs to export their data into a national permit database.

Third, the committee recommends that resources be made available for analyses of the effects of the NSR rule changes on investment behavior and other outcome measures. Census Bureau data appropriate for facility-level analyses are already being collected, but funding would need to be made available for researchers with Census Bureau-approved projects in secure RDCs to be able to analyze the effects of rule changes on the basis of facility-level data. There is enough time to develop a research protocol before adequate data are available, and these analyses could be an important element in evaluating NSR and related regulations.

Finally, the limitations of an econometric approach should be recognized. If firms respond fairly quickly (within a year or two) to the NSR rule changes with a considerable expansion in investment activity, the change in investment should be noticeable. Conversely, it may be possible to provide upper bounds for the effects of the NSR rule changes on investment (we might observe an average increase in investment of 2% and be able to rule out an impact greater than 20%). Still, it is likely that there will be relatively wide bounds on the estimated effects, especially in the initial years in states where relatively few facilities are being affected by the rule changes.

6

Assessing Potential Effects on the Electricity-Generating Sector[1]

INTRODUCTION

As explained in Chapter 4, of all the affected sectors, electric-power generation is the best candidate for the use of a sectorwide simulation model to assess the potential efficiency, technology, and emission implications of New Source Review (NSR) rule changes. In this chapter, we use the electricity-sector model referred to as the Integrated Planning Model (IPM) to bound some of the possible effects of the NSR equipment replacement provision (ERP), the principal change that was to affect the power-generation industry. We define a set of runs of IPM that represent different scenarios concerning the effects of the rule, other interacting air regulations, and background economic and technological conditions. We then compare and interpret the results.

The analyses presented in this chapter were undertaken before the recent appellate court decision struck down the ERP (see Chapter 2 for a discussion of that decision). It is important to keep in mind that the model simulations of the ERP can also be interpreted as simulations of the U.S. Environmental Protection Agency's (EPA's) hourly emission test (see Chapter 2), because no electricity-generating facilities in the ERP analyses are allowed, according to the analytical procedure used by the committee, to make changes that result in an increase in the maximum hourly emission rate, and so all are in com-

[1]Research assistance for this chapter was provided by David Evans of Resources for the Future (RFF) and Nathan Wilson, a presidential management fellow who visited RFF in summer 2005. The committee's Integrated Planning Model runs were undertaken by Boddu Venkatesh, of ICF Consulting.

pliance with the hourly emission test proposal. Consequently, the analyses of this chapter are relevant to any comparison of NSR prior to proposal of the ERP with the EPA hourly emission test proposal.

The arrangements for the IPM model runs were coordinated through the EPA because of the nature of EPA's contractual relationship with ICF Consulting, the owner of IPM. The committee provided scenarios to EPA, and EPA in turn provided the scenarios to ICF and oversaw the implementation of the model. The results of the model runs were then checked for errors by EPA employees and provided to the committee. The committee independently analyzed the results by creating graphs and tables and doing cross-scenario comparisons.

The modeling effort is intended to build on the earlier modeling work done by EPA as a part of its regulatory impact analysis (RIA) of the adoption of the ERP (EPA, 2003c). Our analysis looks at a wider range of potential effects upon generation investment decision making under the agency's prerevision NSR multifactor approach than were examined as part of EPA's RIA. Furthermore, unlike the EPA analysis, which was prepared before the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) (see Chapter 2) were to be put into place, our analysis takes into account the effects of those rules on industry's response to the NSR changes.[2] The design of these runs and their rationale are reviewed in detail in the next section. After reviewing the results, we discuss the limitations of the model and any conclusions based on them. A set of conclusions closes this chapter.

Table 6-1 summarizes the emission-control status of U.S. coal-fired units in 2004. The focus of our analysis is on the 188.5 gigawatts (GW) of large electricity-generating units (at least 100 MW) that as of 2004 lacked flue-gas desulfurization (FGD) controls for sulfur dioxide (SO_2) and on the 190.4 GW of large units that as of the same year lacked selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) controls for nitrogen oxides (NO_x). That focus is based on our assumption that this capacity constitutes the bulk of power-sector emissions that would potentially be affected by the ERP approach. Those uncontrolled units account for 62% and 63%, respectively, of all coal-fired generation capacity. Our analysis excludes 17 GW of smaller units (less than 100 MW), or about 6% of all coal-fired capacity, on the assumption that they would not be suitable candidates for retrofit of FGD or SCR; we assume that those units avoid undergoing NSR.

[2]EPA did its analysis of the ERP before the CAIR rule was officially proposed in January 2005. However, the Clear Skies Bill, which proposes a national cap on sulfur dioxide (SO_2) and nitrous oxides (NO_x) emissions from electricity generators, was introduced in the Senate in 2002. That bill included national caps (on SO_2, NO_x, and mercury from electricity generators) and a proposal to loosen the restrictions imposed by NSR on electricity-generator investments.

TABLE 6-1 Installed Emission Controls, U.S. Coal-Fired Generation Plants, 2004

NO_x Control[a]	SO_2 Control	Capacity (MW)	% Capacity in Group	Number of Boilers	% of Boilers in Group
Large (≥ 100 MW) generating units					
None	None	126,640	45%	432	56%
None	Dry scrubber	9,574	3%	28	4%
None	Wet scrubber	54,259	19%	123	16%
SCR	None	54,146	19%	105	14%
SCR	Dry scrubber	2,002	1%	6	1%
SCR	Wet scrubber	27,066	10%	45	6%
SNCR	None	7,232	3%	29	4%
SNCR	Dry scrubber	248	0%	1	0%
SNCR	Wet scrubber	1,461	1%	6	1%
Total for large units		282,628	100%	775	100%
Small (< 100 MW) generating units					
None	None	16,333	80%	386	84%
None	Dry scrubber	1,773	9%	33	7%
None	Wet scrubber	710	3%	17	4%
SCR	Wet scrubber	254	1%	3	1%
SNCR	None	737	4%	12	3%
SNCR	Dry scrubber	310	2%	6	1%
SNCR	Wet scrubber	263	1%	5	1%
Total for small units		20,380	100%	462	100%

[a]SCR means selective catalytic reduction. SNCR means selective noncatalytic reduction.

DEFINITION OF SCENARIOS

The IPM scenarios are specified on three dimensions. One dimension consists of different versions of EPA's policy regarding the breadth of the routine maintenance, repair, and replacement (RMRR) exemption from NSR with different assumptions about its strictness or direct effects on electricity-generating facility decisions. A second dimension represents assumptions about what other air-pollution regulations will be in place. The third dimension consists of alternative scenarios about economic and technological conditions, such as growth in the demand for electricity, fuel prices, and investment costs for different electricity-production and pollution-control technologies.

Dimension 1: Strictness of Prerevision Routine Maintenance, Repair, and Replacement Policy

IPM, like all national-scale models of the electricity-generating facility sector, does not explicitly represent the full range of life-extension and maintenance alternatives available to power-plant owners, nor does it have data available on the site-specific costs of such alternatives. As a result, IPM cannot explicitly model how the EPA RMRR policy changes the alternatives that individual plants can consider or how the provision affects their costs, and it is not possible for such a model to project with confidence what individual power plants will do under alternative versions of RMRR policy. However, we can hypothesize different levels of aggregate effects of RMRR policy on generating-plant costs, efficiency, and adoption of pollution controls and then use IPM to examine how the industry might have responded in terms of generator retirement, mix of new generation, and emissions. In particular, the strictness of the prerevision NSR RMRR might be characterized in terms of the following:

- How much coal-fired generating capacity is compelled to upgrade to best available control technology (BACT), repower (to combined-cycle capacity, fired either by natural gas or by integrated coal gasification), or retire as a result of NSR review or the threat of such review.
- How much capacity will instead face mild performance deterioration as a result of deferring maintenance rather than undergoing NSR.
- How many allowances would be surrendered as a result of NSR settlements.

As a first step, we simplify the NSR policies into two basic alternatives: the prerevision NSR multifactor approach and the ERP adopted in 2003. We then define variants of industry response to the prerevision NSR approach to represent different assumptions about the possible effects that the previous approach could have had on post-2004 generator decisions about maintenance, retrofits, repowering, and retirement. These cases span a wide range of possibilities, from all nonscrubbed coal-fired generators deciding in the future to avoid NSR by deferring all maintenance to essentially all such generators retrofitting FGD-SCR systems, repowering, or retiring (R/R/R) by 2020.

Table 6-2 summarizes the various cases. For the prerevision NSR rules, two general variants are defined: (1) "avoid," in which generators by and large are able to avoid triggering NSR but at the cost of worsening performance (that is consistent with the assumptions of the RIA of EPA [2003c]), and (2) "R/R/R," in which the outcome would be enforcement policy that leads to substantial amounts of capacity to choose to retrofit FGD-SCR, repower, or retire. The committee has reached no conclusion as to which general variant involves more realistic assumptions. The R/R/R variant assumes that either lawsuits or the possibility of lawsuits will eliminate avoidance of NSR as an alternative for a substantial amount of generation, so that owners must choose between retiring and undergoing NSR; the latter

TABLE 6-2 Summary of NSR Cases Simulated and Assumptions

NSR Case	Which plants must choose between FGD-SCR, retirement, and repowering as the result of NSR?	Which plants face performance deterioration if they avoid NSR by doing no maintenance or life extension?	Allowance surrenders as a result of settlements
Previous RMRR variant 1: "Avoid"	None	All coal-fired generation	None
Previous RMRR variant 2: R/R/R	Specified fraction of pre-1978 coal-fired plants larger than 100 MW; fraction grows linearly from X% in 2008 to 13X% in 2020, with X = 2, 5, 7.5 ("low," "middle," "high" variants, respectively)	Some or none	No surrenders beyond those in settlements made before March 2004
2003 ERP	None	None	Same as above

will result in retrofitting of BACT-compliant emission controls or repowering to BACT-compliant combined-cycle technology. Those general variants represent the range of possible effects on uncontrolled coal-fired capacity that have been put forth by various parties. As noted, the first variant is that which is assumed by EPA (2003c) in its RIA of the 2003 ERP proposal; the other variant is generally consistent with views that have been stated by some stakeholders, including many in the environmental community.[3] The committee has determined that economic, policy, and legal uncertainties are too large to determine which variant is most likely to be correct, so we have adopted a scenario and bounding approach to explore the consequences of alternative assumptions.

The R/R/R variant is simulated by imposing the following constraints on the 188.5 GW of pre-1978 coal-fired units that are at least 100 MW and lacked FGD as of 2004 (Table 6-1):[4] a lower bound is placed in each model year starting in 2008 on the number of megawatts of such capacity that is either retrofitted with FGD, repowered with BACT-compliant combined-cycle technology, or retired; and an analogous bound is applied to the 190.4 GW of pre-1978 coal-fired units greater than 100 MW that lack

[3]For example, Barcott (2004) argues that the old NSR RMRR would have been a major and effective means of reducing power-sector emissions of SO_2 and NO_x by eventually forcing many or most uncontrolled coal plants to retrofit, repower, or retire, eventually pulling emissions below the relevant caps. For a contrary position, see Easterbrook (2004).

[4]Pre-1978 refers to generation units whose emission controls were permitted before the 1978 changes in new source performance standards. Some such plants actually came on line after 1978.

SCR or SNCR, which must either retrofit SCR, repower, or retire. Those bounds simulate a possible outcome of the prerevision NSR RMRR: that some unscrubbed capacity or capacity without SCR would be cleaned up or retired. Variants of the basic alternative assume different levels of the lower bounds, which represent different rates of retrofitting, retiring, or repowering of existing capacity. The lower bounds are tightened over time by increasing the percentage of such capacity that has to make that choice. The first variant (termed the low R/R/R impact variant) assumes that 2% per year of the 188.5 GW of unscrubbed capacity (190.4 GW of capacity without SCR-SNCR) is retrofitted, repowered, or retired in each year from 2007 and 2020. As a result, 2% has been retrofitted by 2008, 4% by 2009, and so forth, reaching 26% in 2020, and flat thereafter.[5] This is the equivalent of about 3,700 MW per year of generation either undergoing NSR (retrofit or repower) or retiring, in the case of the SO_2 constraint. The two other variants assume 5% and 7.5% growth per year (equivalent to 9,400 MW and 14,100 MW per year of R/R/R in the SO_2 case, respectively). The 5%/year scenario (called the middle variant) means that 65% would have been scrubbed, retired, or repowered by 2020, and the 7.5%/year scenario (termed the high variant) reaches 97.5% by 2020. The latter scenario is unlikely because it results in R/R/R substantially above what could credibly occur, because some fraction of uncontrolled generation is likely instead to avoid NSR by deferring maintenance. Furthermore, given the historical rate of scrubber retrofits and the rate of NSR settlements that have already been made, the 14.1-GW/year rate implied by the high variant is large and seems unlikely to be sustainable. Table 5-2 (EIA 2004a) shows that a cumulative 99.6 GW of scrubbers had been installed by 2003, whereas in 1992 there was 71.5 GW, a difference of 28.1 GW in over 2 decades. However, Table 6-3 indicates that owners of electricity-generating facilities capable of producing a total of less than 17 GW have agreed to retrofit scrubbers as the result of NSR enforcement to date. The rate of R/R/R could increase if a few successful enforcement cases persuade the industry that there is no sense in risking enforcement action, but an assumption that 14 GW/year of retrofits could be sustained in every year through 2020 appears extreme. Nevertheless, we analyze the high scenario, treating it as a bounding case.

The rationale for this approach to modeling the R/R/R variant of the previous RMRR is as follows. We are attempting to characterize broadly the potential role of NSR-driven retrofits (scrubbing and SCR) and repowerings and retirements. We distinguish between NSR-triggered retrofits and allowance-triggered retrofits resulting from CAIR or (in the absence of the CAIR) Title IV, enacted as part of the 1990 Clean Air Act amend-

[5]Because IPM simulates only the discrete years 2007, 2010, 2015, 2020, and 2026, the constraint actually applies only in those years.

TABLE 6-3 Year of Installation of Emission-Control Retrofits or Repowering Committed to as a Result of Existing EPA NSR Settlements

Year	SO_2 Postcombustion Control or Repowering (MW)	NO_x Postcombustion Control or Repowering (MW)
2003	326	926
2004	3,255	4,695
2005	781	861
2006	1,985	1,377
2007	1,855	1,519
2008	1,020	1,013
2009	360	1,272
2010	2,754	600
2011	581	1,258
2012	3,565	2,234
2013	0	433
Total	16,482	16,188

SOURCE: Committee analysis of EPA NSR settlements.

ments, and from the NO_x state implementation plan (SIP) call of 1998. An allowance-triggered retrofit is defined as one that is adopted in IPM because it is cost-effective under present and future emission-allowances prices; that is, allowance-triggered retrofit is the lowest-cost method of achieving the emission goals embodied in the caps. In contrast, an NSR-triggered retrofit is the amount of capacity that is R/R/R as a result of NSR enforcement or threat of such enforcement but may not be cost-effective for achieving the caps. Where in time, space, and other dimensions CAIR or other caps are binding, we might expect NSR-triggered retrofits to have little effect on national emissions, although there may be some local effects. They might simply displace allowance-driven retrofits, shifting emission reductions in space and time but having relatively small effects on aggregate emissions. Under those conditions, even large differences in the rate of NSR-triggered retrofits would make little difference in overall emissions. But we can imagine a rate of NSR-triggered retrofits that would be great enough to overtake the CAIR rule (or, in its absence, Title IV and the SIP call), in which case some difference in aggregate national emissions might be attributable to the change in the NSR rules.

Therefore, we can think of triggered retrofits as being approximated by a requirement that a specified percentage of existing uncontrolled capacity be retrofitted, retired, or repowered in each year. For example, if the triggered retrofits happened at 5% per year (assuming that 2008 is the first year when retrofits could feasibly take place), then as indicated above, 15% of currently uncontrolled capacity (as of 2004) would be subject to triggered retrofits (or repowering or retirement) by 2010, 40% by 2015, and 65% by 2020.

The three R/R/R variants of EPA's prerevision NSR multifactor approach represent different assumptions about the pace and effectiveness of enforcement. When estimating the costs of implementing the specified fraction of R/R/R, this method should provide an estimated lower bound on cost because the lowest-cost method of meeting the constraint is chosen. This lower-bounding approach allows the model to choose which uncontrolled plants must scrub, retire, or repower on a lowest-cost basis, which of course may not be how EPA chooses plants to be subject to enforcement actions. However, because we cannot predict precisely which generating units will be subjected to such actions in the future or would for other reasons choose to retrofit, retire, or repower and in what order, the use of the lower bound is a simple and transparent way to simulate the possible effect of enforcement of the previous RMRR on power plants.

Because NO_x and SO_2 emission caps are binding in many years in the simulations, an important assumption concerns the number of allowances that are surrendered as part of enforcement actions. As Table 6-2 indicates, the R/R/R scenarios assume no further allowance surrenders than have already been announced. It is possible that under the prerevision RMRR, additional allowance surrenders could occur. If there would be many more allowances surrendered under prerevision NSR rules, the NO_x and SO_2 constraints under the SIP call, Title IV, and CAIR would effectively be tighter, and national emissions probably lower. However, it is uncertain whether and how many additional allowance surrenders would have occurred under the prerevision RMRR, and thus, it would be speculative for the committee to estimate how many more would have occurred under different policies. Therefore, we decided to make no specific estimate.

Dimension 2: Other Regulations

The electric-power industry is affected by a number of air-pollution laws at both the federal and state level. There are therefore many potential interactions that could be investigated. The most important are cap-and-trade programs. We defined two alternative other regulations or policies to consider the issue of how NSR would interact with different caps on NO_x and SO_2 emissions. Those policies are shown as columns in Table 6-4: non-CAIR (present Title IV and NO_x SIP call, under the assumption that court or other challenges result in withdrawal of CAIR and CAMR) and CAIR-CAMR, as promulgated by EPA. The CAIR-CAMR simulation includes the best available retrofit technology (BART) provisions associated with the recently promulgated amendments to the regional haze rule (EPA, 2005e). There could be variants on the CAIR-CAMR scenario because there may be

TABLE 6-4 Combinations of NSR ERP Cases and "Other" Air Regulations Simulated

NSR Case	"Other" Case 1: Title IV and NO_x SIP Call	"Other" Case 2: CAIR-CAMR
Previous RMRR variant 1: "Avoid"	Analysis of effects relative to 2003 ERP based on EPA (2003c)	Not simulated
Previous RMRR variant 2: R/R/R	IPM simulations: Three variants run (various lower bounds)	IPM simulations: three variants run (various lower bounds)
2003 ERP	EPA (2005e) base case	EPA (2005e) CAIR-BART-CAMR run

lawsuits challenging CAIR, which may result in changes in the caps or the timetable. Other developments, such as revised ambient standards for airborne particles, could result in further restrictions. Furthermore, individual states can choose to opt out, although their share of emission reductions (based on Section VII of the preamble to the final CAIR, 70 Fed. Reg. 25255) would still need to be achieved by other means. This could change the spatial distribution of emissions if not the total. However, time and resource limitations meant that we could not consider such variants of CAIR.

The combinations of "other policies" and NSR policies considered in this chapter are shown in Table 6-4. The table also indicates what runs of IPM were used to assess each case. According to EPA statistics, of the 188.5 GW of unscrubbed capacity considered in the R/R/R scenarios, 165.8 GW lies in the CAIR region and an additional 16.5 GW is subject to BART. Of the 190.4 GW of existing non-SCR capacity that is subject to the R/R/R constraint, 144.1 GW is subjected to CAIR and 41.7 GW to BART. Thus, 97% of the capacity subjected to our technology lower bound in the R/R/R prerevision NSR RMRR scenario comes under the CAIR caps or the BART program.[6] (Of course, capacity subject to the cap is not required to go through R/R/R.)

Because of budget and time limitations, we used the EPA (2003c) RIA results to represent the "avoid" variant of the previous multifactor test. We do not expect the qualitative results to change significantly if that variant

[6]In the CAIR-CAMR runs, the impact of BART was modeled as follows, consistent with other EPA analyses of BART using IPM. If a BART unit already has SCR for NO_x control, IPM modeled year-round operation of the SCR. On the other hand, if a unit did not have SCR, IPM modeled state-of-the-art NO_x combustion controls, except for cyclone units for which IPM modeled SCR. Concerning SO_2, if a BART unit did not already have FGD, IPM applied the following emission-rate limit to the unit: the higher of 0.15 lb/million Btu or a 95% reduction from the sulfur grade used by the unit in the base case.

were rerun. As described in Appendix B of the RIA, IPM simulations assume that in the face of the previous policy, generator owners would opt to avoid undergoing NSR by deferring maintenance. The assumed result would be a steady deterioration of 0.1%/year in efficiency (heat rate) and capacity; in contrast, the RIA assumed that the ERP would increase maintenance, yielding improvements in efficiency, capacity, and, in some scenarios, plant availability. The RIA considered five "increased maintenance" cases with various assumptions. The results showed that the Title IV and SIP emission caps remain binding throughout the entire time horizon of the IPM simulation. Consequently, the deterioration that the RIA assumed in plant capacity and efficiency yielded higher generation costs but essentially the same NO_x and SO_2 emissions as the "increased maintenance" cases. SO_2 emissions varied between the cases by no more than 0.5% in 2010-2020. NO_x emissions varied more (by up to 2.5%) because the SIP cap applies only during the ozone season[7] and applies to a limited number (22) of states. However, the emission differences between the prerevision NSR rule and the "increased maintenance" cases were 1% or less for most of the cases and years considered because the emission caps are always binding. Therefore, we conclude that the presence of emission caps is what determines the total emissions in the "avoid" variant. Hence, if the prerevision NSR RMRR results in all generators, avoiding NSR, the national NO_x and SO_2 emission differences between the prerevision RMRR and the proposed ERP would be minor.

EPA (2003c) considered the "avoid" variant only under present SO_2 and NO_x rules. We expect that a tightening of the emission caps, as promulgated under CAIR, would not change the basic IPM result in EPA (2003c) that an "avoid ERP" strategy of deferred maintenance would leave emissions at the cap and result in higher costs. That is because the logic of market-simulation models, such as IPM, is such that if a constraint is binding in one solution, it will remain binding if it is tightened.[8] The magnitude of cost increases would no doubt differ from a non-CAIR scenario, but our main focus here is on the emission effects. Essentially, by making the aggregate emission caps stricter in the East and Midwest and, in the case of NO_x, broader in geographic scope, CAIR raises the cost of maintenance deferrals that would increase emissions at individual facilities. Thus, CAIR makes it even less likely that aggregate emissions would be higher under an "avoid ERP" strategy. Given that little was likely to be learned, we chose to forgo the cost of an additional IPM run for a CAIR variant of the "avoid ERP" strategy.

[7]The months when ambient ozone in an area is more likely to reach unhealthful concentrations.

[8]Because the geographic and temporal scope of CAIR is wider than the SIP NO_x call, we anticipate that the minor NO_x increases that EPA (2003c) found in the "avoid" scenario relative to the base case would become even smaller if CAIR-type constraints were imposed instead.

The R/R/R variants are analyzed under both a non-CAIR-CAMR and a CAIR-CAMR regulatory regime with IPM runs undertaken at the request of the committee. The technology, cost, and other IPM assumptions are the same as in the EPA (2005e) analyses of the June 15, 2005, amendments to the Regional Haze Rule. (That rule led to the BART requirements that will lead some western generators, outside the CAIR region, to retrofit with scrubbers and postcombustion NO_x controls.) The IPM database did not include the most recent settlements under the NSR rule, but in the committee's judgment the differences that those settlements would make in the analyses were too small to justify the delay and expense involved in updating the database.[9] The limitations and assumptions of the IPM model are discussed later in this chapter.

The last row of Table 6-4 shows that the 2003 ERP is analyzed on the basis of the EPA (2005e) base cases, which assume that under the new rule no further settlements that result in mandatory retrofit of FGD-SCR are made under NSR rules beyond settlements that were in place as of March 2004.[10] Those base cases include both non-CAIR-CAMR and CAIR-CAMR scenarios. These are compared with the IPM R/R/R runs (next to last row) to assess possible emissions, cost, and technology effects of the ERP, if it is assumed that the effect of retaining the prerevision NSR approach would

[9]Two recent settlements between EPA and electricity-generating facilities are not in the IPM database, including Ohio Edison (Sammit Units 1-7; Eastlake 4,5; Burger 7,8) and Illinois Power (Baldwin 1,2,3; Havana 6; Hennepin 1,2; Wood River 4,5; Vermillion 1,2). In addition, a state settlement with Mirant is omitted (Potomac River 3,4,5; Morgantown 1,2). A total of 7,805 MW is involved. Of that capacity, 4,936 MW is chosen to be scrubbed anyway as part of the IPM CAMR-CAIR base case run (the run represented by the last cell in the last row of Table 6-3), and 2,869 MW is not (primarily the Baldwin plant). The 2,869 MW is about 1.5% of the total of 188.5 GW of unscrubbed coal capacity in 2004. That small value indicates that omitting those settlements would not greatly distort the solution in that case. IPM also does not have some other recent state NSR settlements. Known examples include the NEG and AES cases in New York. However, these sources may have retrofit anyway in response to state cap-and-trade programs.

The other aspect of the recent settlements that is not included in the IPM runs is any systemwide restriction on annual emissions and retirement of allowances. Such retirements would have the effect of lowering the relevant emission caps by the amounts involved. Consequently, national emissions may be overstated in our runs, but because the retirements are small we judge that any such overstatement would not affect our conclusions about the effects of the old NSR RMRR compared with the ERP. For Illinois Power, roughly 30,000 Title IV SO_2 allowances must be surrendered each year after 2011. Ohio Edison is required to retire all excess allowances above those that it was initially allocated, but the exact number is not specified in the settlement.

[10]Whether this assumption is valid depends on future judicial holdings regarding the legality of EPA's enforcement strategy. An alternative assumption that would not change these solutions is that additional settlements result in retrofits that the generating-capacity owners would have voluntarily undertaken in any event under CAIR-CAMR.

be to force a substantial amount of nonscrubbed coal capacity to face the R/R/R decision. Those base cases are not compared with the "avoid" scenarios, because the EPA (2003c) RIA IPM runs are based on an earlier set of economic and technological assumptions.

Dimension 3: Alternative Economic, Market, and Technology Scenarios

It was not possible to conduct a thorough set of sensitivity analyses of the cases in Table 6-4 with respect to an array of economic and technology assumptions. Because the IPM analyses indicate that very little uncontrolled coal capacity would be retired by 2020 in any of the scenarios of Table 6-4, we decided to consider whether alternative plausible assumptions might result in more retirements. We focused on the most extreme, bounding R/R/R case ("high," with a 7.5% increase per year in the amount of uncontrolled coal capacity that must decide to retrofit, repower, or retire) under the CAIR-CAMR scenario.

Natural gas, renewables, and integrated gasification combined cycle (IGCC) were considered because they would be the primary candidates for substituting for retired uncontrolled coal capacity. These sensitivity analyses are performed on the bounding "high" case because it is the scenario in which the prerevision RMRR has the greatest effect on emissions. The "low" and "middle" cases, in which emissions are at the cap in most or all years, would not exhibit as much sensitivity if subjected to the same analyses, because if emissions are at the cap, they are likely to stay at or near the cap.

Two additional IPM runs were specified for the sensitivity analyses using the 7.5% R/R/R case. The first sensitivity analysis had the following changed assumptions relative to the base case assumptions:

- 20% lower investment costs for renewable-energy plants, including wind, solar, landfill gas, biomass, and geothermal.
- Lower investment costs for IGCC plants: 15% lower in 2010, 20% lower in 2015, and 25% lower in 2020 and 2026. In addition, the capital cost of repowering coal steam to IGCC was lowered by 20%.

The second sensitivity analysis made the same investment-cost assumptions as the first, and assumed lower natural gas prices. That was accomplished by scaling gas-supply curves downward by 15% in 2010, 20% in 2015, and 25% in 2020 and 2026. It should be noted that the base case prices for natural gas in the IPM runs were already low—just over $3.00 per million Btu in $1999, measured at the Henry Hub. In contrast, gas prices that actually prevailed in 2005 were much higher, peaking at about four times that price in October 2005.

We did not consider a scenario with higher gas and investment costs for alternative-energy sources, because such assumptions would yield the same generally low rates of retirement for coal plants as the base case assumptions.

As discussed later in the chapter, we considered the national NO_x and SO_2 emission reductions occurring under the most extreme (7.5%/year) R/R/R case under CAIR, and calculated the lowest-cost means of achieving those reductions in the same years when they occur. That simulates the use of a policy of caps to achieve the same national emission goals.

RESULTS

Comparison of Emissions

In Table 6-5, we summarize the simulated SO_2 and NO_x emissions effects of each prerevision NSR RMRR variant ("avoid" and three R/R/R cases) relative to the ERP. These results are discussed in more detail later in this section. Four of the 5 years calculated by the IPM are presented (2007, 2010, 2015, and 2020); 2026 is omitted because the committee judges the last year's results to be less reliable than those of earlier years.[11] As mentioned, the estimated effects in the "avoid" case are based on the EPA (2003c) RIA, which considers only the Title IV and NO_x SIP call caps. The R/R/R cases' effects are calculated by using the IPM runs requested by the committee. The effects are expressed as percentage changes relative to the ERP base case (last row of Table 6-4) for each of the two assumed sets of emission caps. Figures 6-1 through 6-4 present the same results in graphic form, expressed as total tons (Figures 6-1 and 6-2) and tonnage differences between the prerevision NSR RMRR and base case results (Figures 6-3 and 6-4). Those figures show the changes in emissions resulting from the three variants of the R/R/R prerevision NSR RMRR scenario relative to the 2003 ERP base case over the 2007-2020 period under both

[11]This conclusion is reached not only because economic and technological projections become more uncertain for years that are further in the future but also because decisions in the last year of a model run can be subject to "end effects," which are distortions in capital investments that occur because the benefits and costs of those investments for later years are not considered (Grinold 1983). Another distortion can occur because banked allowances might have value past that year, which could increase the price of allowances in early years, altering the patterns of emissions reductions. In solutions where emissions are below the cap in 2026, such as the more stringent R/R/R scenarios, there would be no distortion, because the allowances would be without value in that and subsequent years. In particular, the 7.5% R/R/R runs show zero value for Title IV/NO_x SIP allowances (in the Title IV/SIP case) and CAIR allowances for SO_2, NO_x, and Hg (in the CAIR case), confirming that there would be no such distortion, at least in those situations.

TABLE 6-5 Summary of SO_2 and NO_x Emission Effects of Prerevision NSR RMRR Relative to ERP (Base Case) Under Base Case Economic and Technology Assumptions (Rounded to Nearest Percent)

NSR Case	"Other" Case 1: Title IV/NO_x SIP Call[a]	"Other" Case 2: CAIR-CAMR, as Promulgated[a]
Prerevision RMRR policy, "avoid" variant (compared with 2003 ERP from EPA [2003c] RIA)	$\Delta SO_2 > -1\%$ all scenarios and years (small positive values if ERP assumed to result in increased maintenance) $\Delta NO_x > -2.5\%$ all scenarios and years (usually, $\Delta NO_x > -1\%$) (decreases occur mainly outside SIP region and ozone season) (small positive values if the ERP assumed to result in increased maintenance)	Not simulated
Prerevision RMRR, "low" R/R/R variant: 2%/yr of uncontrolled coal capacity retrofit, repower, or retire (compared to ERP, IPM base cases)	ΔSO_2: 0% (2007), +2% (2010), –2% (2015), 0% (2020) ΔNO_x: 0% (2007), –4% (2010), –6% (2015), –8% (2020)	No changes in SO_2, NO_x emissions
Prerevision RMRR, "mid" R/R/R variant: 5%/yr of uncontrolled coal capacity retrofit, repower, or retire (compared to ERP, IPM base cases)	ΔSO_2: +10% (2007), 0% (2010), –2% (2015), –1%(2020) ΔNO_x: 0% (2007), –5% (2010), –14% (2015), –27% (2020)	ΔSO_2: +1% (2007), 0% (2010), +3% (2015), –4% (2020) ΔNO_x: 0% (2007-2015), –12% (2020)
Prerevision RMRR, "high" R/R/R variant: 7.5%/yr of uncontrolled coal capacity retrofit, repower, or retire (compared to ERP, IPM base cases)	ΔSO_2: +19% (2007), –2% (2010), –3% (2015), –59% (2020) ΔNO_x: 0% (2007), –7% (2010), –25% (2015), –46% (2020)	ΔSO_2: +7% (2007), +10% (2010), –5% (2015), –21% (2020) ΔNO_x: 0% (2007, 2010), –7% (2015), –34% (2020)

[a]Negative number for ΔSO_2 or ΔNO_x indicates that estimated prerevision NSR RMRR emissions are less than ERP emissions; positive number indicates that prerevision NSR RMRR emissions are more.

the Title IV/NO_x SIP call and CAIR-CAMR systems of caps.[12] For reference, Figures 6-1 and 6-2 also show the historical SO_2 and NO_x emissions by U.S. electricity-generating facilities.

[12]Thus a given percentage change in Table 6-5 will represent different tonnages in different years. For instance, because total emissions are highest in 2007, an X% change in 2007 will represent a larger tonnage than the same percentage in, say, 2020.

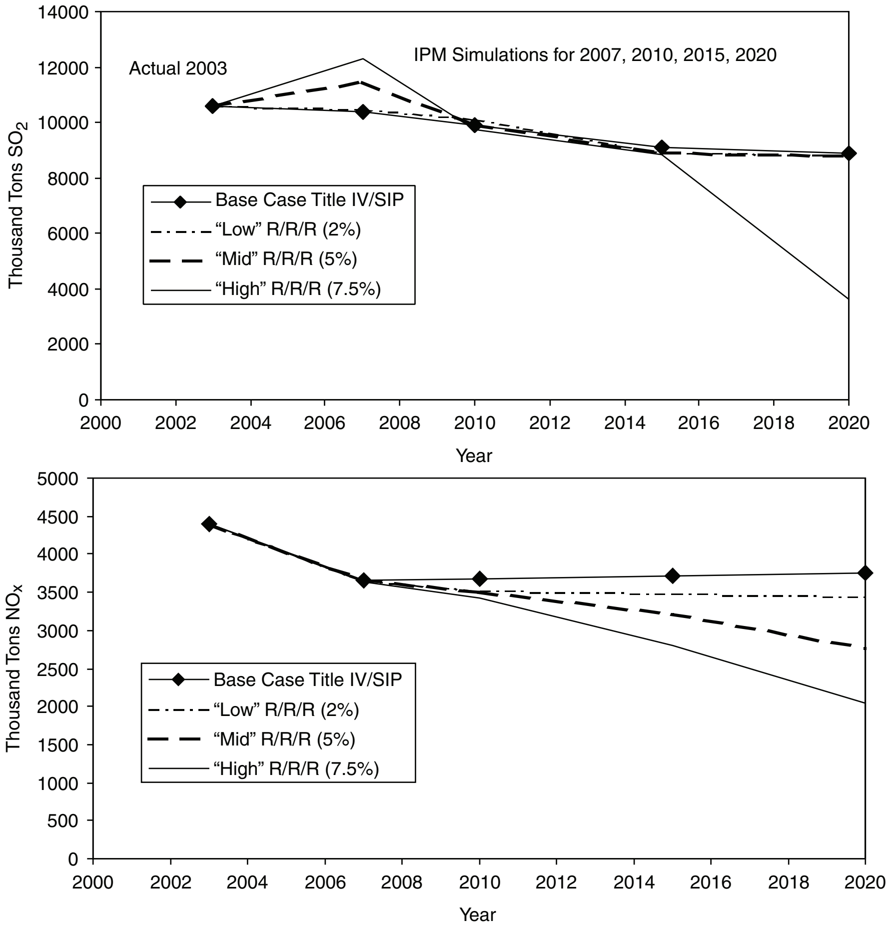

FIGURE 6-1 National SO_2 and NO_x emissions under R/R/R and base case scenarios, under Title IV and SIP caps (no CAIR-CAMR).

As explained above, a comparison of the nationwide NO_x and SO_2 emissions of an "avoid" prerevision NSR RMRR scenario with the ERP has been undertaken by EPA (2003c) in its RIA, and by other national modeling studies.[13] The basic conclusion of EPA's analysis, summarized earlier

[13]Two other national analyses of the ERP change have been undertaken that also assume that electricity-generating facilities adopt the "avoid" strategy under the old NSR rule. Both used the National Energy Modeling System (NEMS), a bottom-up model of the U.S. energy sector, briefly mentioned in Chapter 4. The NEMS analysis by EPA (2003c) adopted a wider range of assumptions than the IPM-based RIA concerning efficiency and capacity availability improvements resulting from the rule change. The conclusions are qualitatively the same,

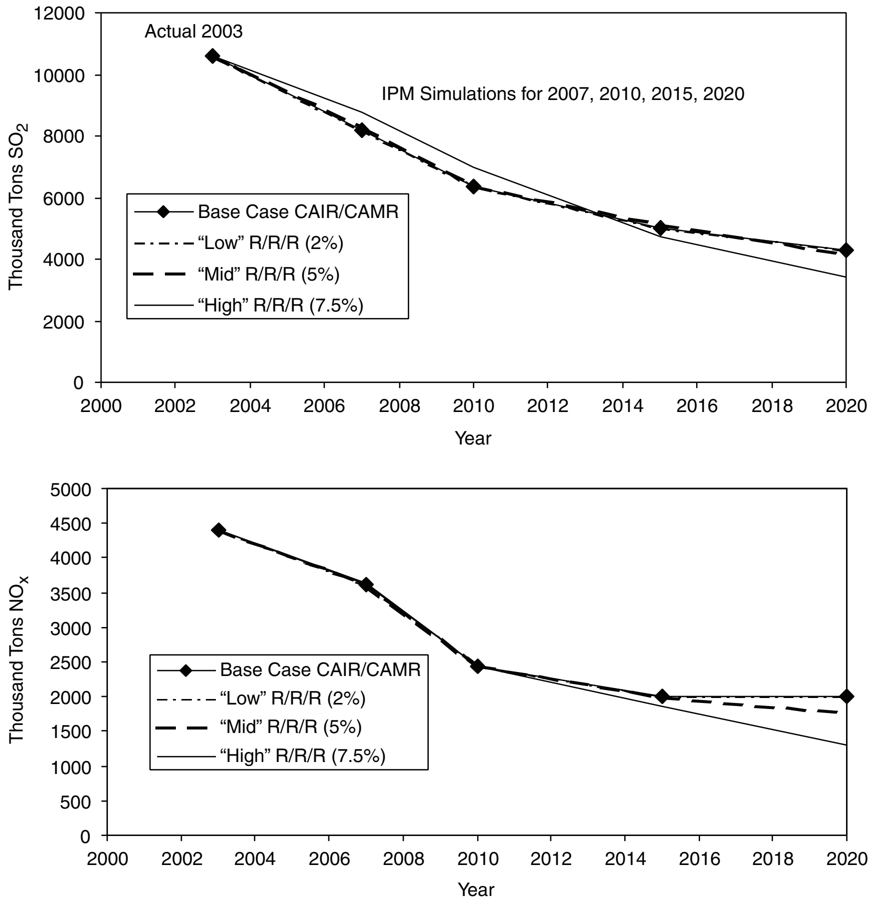

FIGURE 6-2 National SO_2 and NO_x emissions under R/R/R and base case scenarios, under CAIR-CAMR emission caps.

however; the existence of emission caps dampens or eliminates any national emission effect. The Title IV cap implies that SO_2 emissions are changed slightly, if at all, and NO_x emissions vary somewhat because the SIP call cap is geographically and seasonally limited. DOE (2003) also used NEMS in its analysis of the rule change but with a narrower range of efficiency and availability assumptions. In particular, fuel efficiencies were assumed to improve by 5% or 10% and capacity availabilities by 0-2% under the ERP. The EPA NEMS analysis did not consider capacity improvements, but the second analysis assumed an improvement in capacity equal to half the efficiency improvement. The changed assumptions did not materially alter the SO_2 and NO_x conclusions of the earlier NEMS analysis; cumulative SO_2 emissions were unchanged, and annual NO_x emissions under the ERP differed from the old NSR RMRR case by –6% to +0.2%. The later analysis did quantify cost savings, net of an assumed cost of \$100/kW for capacity increases, yielding cumulative cost savings over the 24-year simulation of \$10-100 billion.

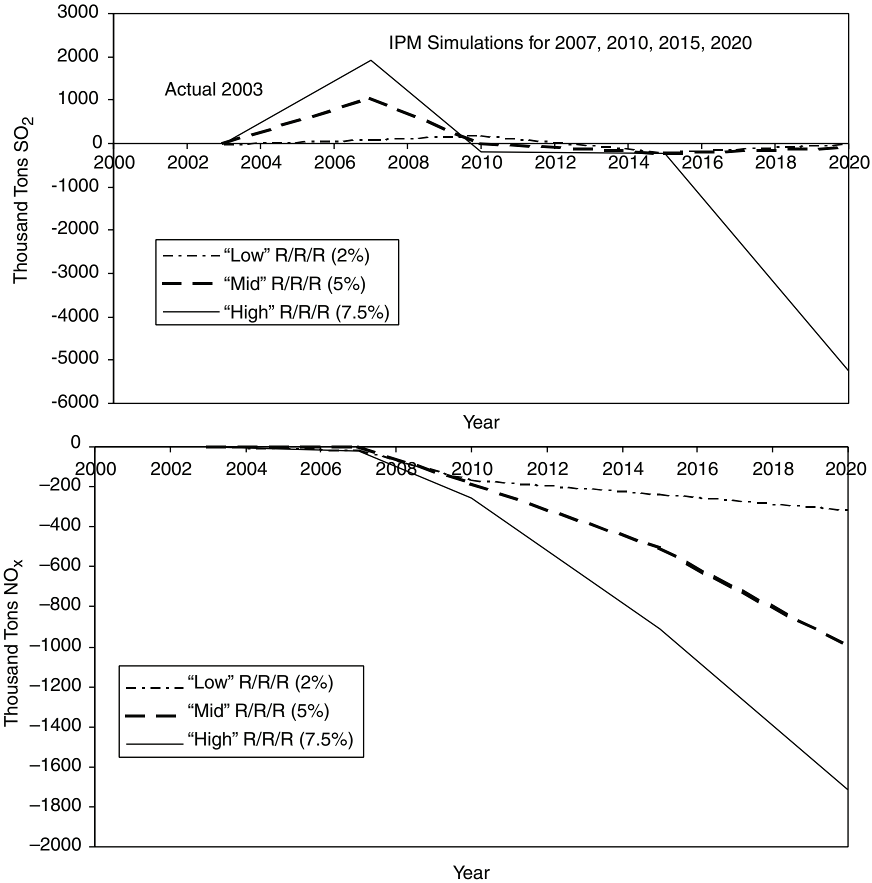

FIGURE 6-3 Difference in national SO_2 and NO_x emissions under Title IV NO_x SIP call emission caps (comparison of prerevision NSR RMRR with the ERP base case in Figure 6-1).

in this chapter, is that in the presence of tight emission caps shifts in plant efficiency and capacity due to the ERP would not appreciably affect total national emissions of these pollutants. As mentioned earlier, the committee has reached no conclusion as to whether the "avoid" assumptions are more realistic than the assumption of the R/R/R cases that the prerevision NSR RMRR would induce additional large amounts of R/R/R.

We have not considered the effect of the "avoid" variant of the prerevision NSR RMRR under the tighter caps that would prevail under CAIR-CAMR, because, as pointed out above, tighter caps will not change the

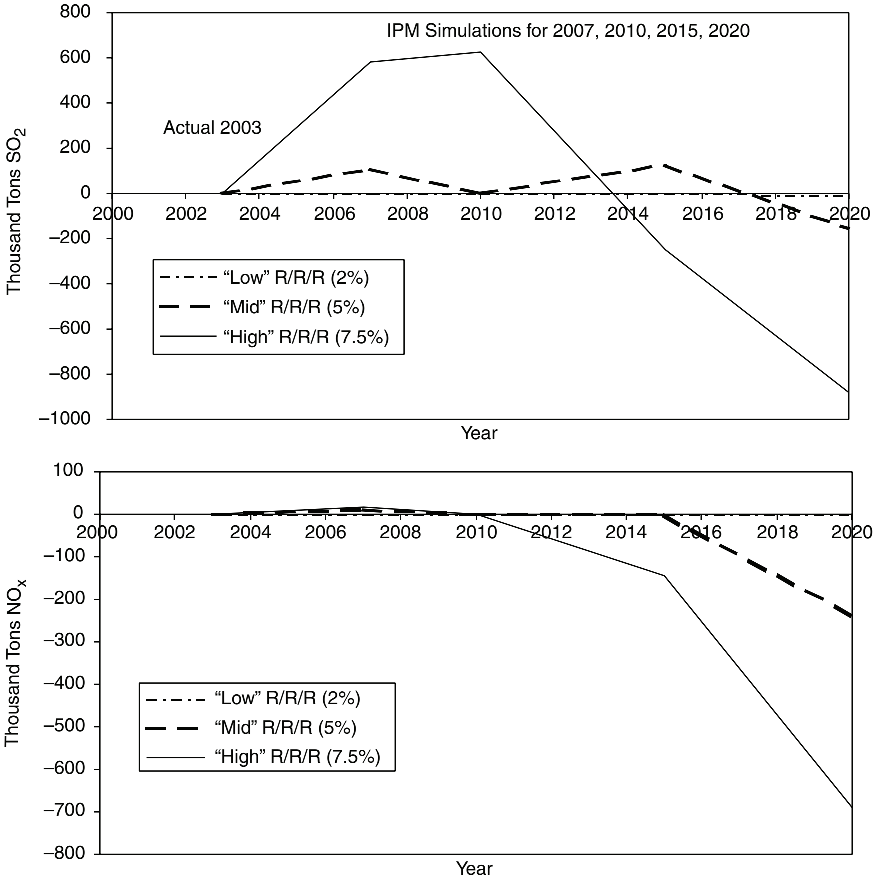

FIGURE 6-4 Difference in national SO_2 and NO_x emissions under CAIR-CAMR emission caps (comparison of prerevision NSR RMRR with the ERP base case in Figure 6-2).

qualitative results if emissions are already at the cap. Rather, emissions will remain at the cap.

The rest of this section is devoted to our comparison of the R/R/R variants of the prerevision NSR RMRR with the ERP. Tables 6-6a to 6-6d provide some details on the prerevision NSR R/R/R and ERP simulations for the years 2007, 2010, 2015, and 2020, including information on the mix of generation sources, the types of generation capacity, sources of coal, and what types of R/R/R decisions are made in each case. The results show that generating-plant owners nearly always respond to an assumed mandate to retrofit, repower, or retire by retrofitting emission controls. Imposition of even the most aggressive technology constraint ("high") results in a decision by less than 2% of the uncontrolled capacity to retire or repower.[14] The solutions show relatively little difference in the share of coal-fired generation but some variation in the sources of coal. The latter result comes about because differing amounts of scrubbing and allowance prices cause electricity-generating facilities to switch between coal sources with differing costs and sulfur content.

Figure 6-5 shows the trends over time in the cumulative amount of capacity scrubbed since 2007 for the R/R/R and base case solutions and one additional solution ("Minimal Cost") discussed later. Under the Title IV-NO_x SIP call regulatory scenario (Figure 6-5 top), the R/R/R constraint is binding in each year, and the amount of scrubbed capacity increases linearly according to the assumptions in each scenario. But under the CAIR-CAMR-BART scenario (Figure 6-5 bottom), the R/R/R constraint has negligible effect in the early years. Only in the later years does that constraint bind, and then only in the "middle" and "high" R/R/R scenarios. Because of the higher allowance prices under CAIR-CAMR than under Title IV, sufficient scrubber capacity is added to more than meet the "low" R/R/R constraint in all years and the "middle" R/R/R constraint through 2015. In those cases, enforcement of the prerevision NSR RMRR results in scrubber installations that would have occurred anyway, although not necessarily at the same places, possibly increasing costs.[15] However, by 2020, the "high" R/R/R scenario has resulted in 50% more retrofits than the other cases.[16]

The emission results for prerevision NSR RMRR R/R/R variants show the following general patterns. Under the assumption that only Title IV and the NO_x SIP call caps are in place, all three of the R/R/R scenarios yield some emission changes. That is, EPA's prerevision NSR RMRR policy is estimated to have some effects on national emissions under scenarios in which a minimum of 2-7.5% per year of the nonscrubbed coal capacity in 2004 chooses to R/R/R, assuming no tightening of emission caps. The effects are important for the 2%/year and 5%/year scenarios only for NO_x. SO_2

[14]Ellerman (1998) discussed why existing power plants seem to being staying on line indefinitely. He identified improvements in sensing, diagnostic, and computing equipment as a major contributor to lower costs of maintenance at existing plants and longer lives as a result.

[15]In the IPM model, if the R/R/R constraint does not bind, the mathematics of constrained cost minimization will imply that costs will not increase and scrubber installations will occur at the same places and times as in the lowest-cost CAIR-CAMR solution. However, in actuality, EPA enforcement priorities and electricity-generating facility response to those priorities could result in changes in locations of scrubbing without lowering national emissions, so costs would increase.

[16]The scrubber installations are mostly wet scrubbers. For instance, of the 181 GW of capacity scrubbed in that year because of that constraint, 25.7 GW has installed dry scrubbers and 155.3 GW was fitted with wet scrubbers.

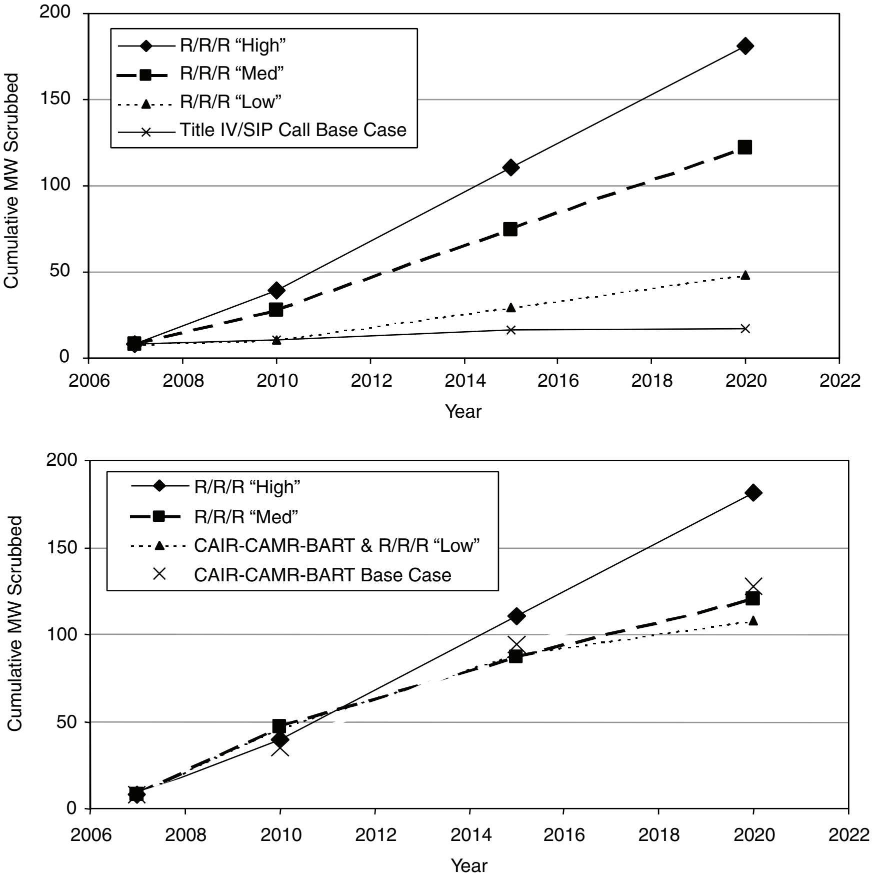

FIGURE 6-5 Cumulative FGD retrofits since 2007 for base case and prerevision NSR RMRR solutions under (top) Title IV-NO_x SIP call and (bottom) CAIR-CAMR-BART.

emissions show some changes for the 5% scenario, but the anticipated 2% decrease in 2010 is more than matched by a predicted increase of 10% in 2007, with only negligible total effects over the entire time horizon of IPM. Only for the "high" (7.5%) scenarios are there so many retrofits of scrubbers that the SO_2 emissions are pulled below the Title IV cap by more than about 1-2%, and then only in 2020. By that year, nearly all coal capacity is scrubbed, and SO_2 emissions fall to 41% of the base case value. Meanwhile, NO_x emissions in that year are 54% of the base case values. Thus, installing emission controls on 62.5% of the 2004 uncontrolled coal capacity is not sufficient to pull both pollutants much below their caps, this being (a) the percentage scrubbed in 2020 in the "middle" (5%) scenario and in 2015

TABLE 6-6a Detailed Results of IPM Simulations for Year 2007

Other regulations:	Title IV and NO_x SIP Call			
Lower Bound on R/R/R (%/yr increase)	ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
National emissions				
SO_2 (million short tons)	10,374	10,463	11,433	12,314
NO_x (million short tons)	3,665	3,653	3,662	3,643
CO_2 (million metric tons)	2,391	2,390	2,392	2,387
Hg (short tons)	52.0	52.2	52.9	53.3
Generating capacity (GW)				
Coal	305	305	305	302
Hydro	110	110	110	110
Nuclear	100	100	100	100
Oil-natural gas	387	387	387	387
Other	12	12	12	12
Renewables	13	13	13	13
Total	927	927	927	924
Energy generation (thousand GWh)				
Coal	2,161	2,160	2,164	2,158
Hydro	298	298	299	299
Nuclear	785	785	785	785
Oil-natural gas	655	656	653	658
Other	68	68	68	68
Renewables	54	54	54	54
Total	4,021	4,021	4,023	4,022
Retrofits (cumulative GW, 2007-2020)				
FGD[a]	7.8	8.0	8.0	8.0
SCR[a]	20.2	21.7	21.8	22.3
SNCR	2.5	0.2	0.2	0.2
ACI[b]	0.0	0.0	0.0	0.0
Coal retirements and repowering (cumulative GW, 2007-2020)				
Repower to CC	0.0	0.0	0.0	0.0
Repower to IGCC	0.0	0.0	0.0	0.0
Coal retired	0.0	0.0	0.0	2.2
Oil-gas retired	41.1	41.0	40.9	40.1
Total	41.1	41.0	40.9	42.3
Coal production (million tons)				
Appalachia	334	332	335	342
Interior	164	170	187	200
West	577	572	551	525
Total	1,075	1,074	1,073	1,067
Total cost ($ billion 1999)	81.2	81.2	81.0	80.9

[a]IPM database assumes that 107 GW and 105 GW of coal-fired capacity are retrofitted with FGD and SCR, respectively, before 2007.
[b]Activated carbon injection, a mercury-control technology.

CAIR-CAMR-BART			
ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
8,172	8,173	8,279	8,756
3,613	3,613	3,623	3,629
2,369	2,370	2,374	2,380
47.4	47.4	47.5	49.2
300	300	301	302
110	110	110	110
100	100	100	100
387	387	387	387
12	12	12	12
13	13	13	13
922	922	923	924
2,127	2,128	2,134	2,144
292	292	293	295
785	785	785	785
685	685	680	670
68	68	68	68
54	54	54	54
4,011	4,012	4,014	4,016
8.0	8.0	8.0	8.0
17.1	17.1	17.9	18.8
0.2	0.2	0.2	0.2
0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0
4.2	4.1	3.1	2.3
40.6	40.5	40.5	40.5
44.8	44.6	43.6	42.8
299	299	303	312
138	138	140	142
628	628	625	617
1,065	1,065	1,068	1,071
82.3	82.3	82.3	81.8

TABLE 6-6b Detailed Results of IPM Simulations for Year 2010

Other Regulations:	Title IV and NO_x SIP Call			
Lower Bound on R/R/R (%/yr increase)	ERP (0%)	"Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
National emissions				
SO_2 (million short tons)	9,908	10,094	9,899	9,719
NO_x (million short tons)	3,679	3,516	3,496	3,426
CO_2 (million metric tons)	2,470	2,469	2,474	2,472
Hg (short tons)	50.6	50.7	50.9	49.0
Generating capacity (GW)				
Coal	305	305	305	302
Hydro	110	110	110	110
Nuclear	101	101	101	101
Oil-natural gas	393	393	394	395
Other	12	12	12	12
Renewables	13	13	13	13
Total	934	934	934	933
Energy generation (**thousand GWh**)				
Coal	2,198	2,195	2,201	2,199
Hydro	297	298	300	301
Nuclear	799	799	799	799
Oil-natural gas	777	780	776	777
Other	71	71	71	71
Renewables	56	56	56	56
Total	4,198	4,199	4,203	4,202
Retrofits (**cumulative GW, 2007-2020**)				
FGD[a]	10.4	11.0	27.8	39.8
SCR[a]	25.9	24.7	28.2	40.2
SNCR	5.0	0.2	0.2	0.2
ACI[b]	0.3	0.2	0.2	0.2
Coal retirements and repowering (**cumulative GW, 2007-2020**)				
Repower to CC	0.9	0.9	0.9	0.9
Repower to IGCC	0.1	0.1	0.1	0.1
Coal retired	0.0	0.0	0.0	2.2
Oil-gas retired	42.0	41.7	41.5	40.6
Total	43.0	42.7	42.5	43.8
Coal production (**million tons**)				
Appalachia	325	329	345	353
Interior	161	164	187	210
West	603	594	554	513
Total	1,089	1,087	1,086	1,076
Total cost (**$ billion 1999**)	85.5	85.6	85.8	86.3

[a]IPM database assumes that 107 GW and 105 GW of coal-fired capacity are retrofitted with FGD and SCR, respectively, before 2007.
[b]Activated carbon injection, a mercury-control technology.

CAIR-CAMR-BART			
ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
6,344	6,344	6,343	6,967
2,439	2,439	2,438	2,438
2,445	2,445	2,447	2,453
35.3	35.3	35.5	36.7
300	300	301	302
110	110	110	110
101	101	101	101
394	394	394	394
12	12	12	12
13	13	13	13
930	930	931	932
2,160	2,160	2,162	2,173
290	290	290	291
799	799	799	799
812	812	810	800
71	71	71	71
56	56	56	56
4,188	4,188	4,188	4,190
46.4	46.4	47.0	39.6
41.1	41.2	42.2	43.7
0.2	0.2	0.2	0.2
2.2	2.2	1.8	1.7
0.9	0.9	0.9	0.9
0.1	0.1	0.1	0.1
4.7	4.6	3.6	2.4
41.2	41.1	40.9	41.1
46.9	46.7	45.5	44.5
303	303	305	315
169	169	169	164
589	589	587	587
1,061	1,061	1,062	1,066
88.2	88.2	88.3	87.9

TABLE 6-6c Detailed Results of IPM Simulations for Year 2015

Other Regulations:	Title IV and NO_x SIP Call			
Lower Bound on R/R/R (%/yr increase)	ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
National emissions				
SO_2 (million short tons)	9,084	8,873	8,865	8,854
NO_x (million short tons)	3,721	3,487	3217	2,808
CO_2 (million metric tons)	2,599	2,597	2,604	2,597
Hg (short tons)	48.9	48.7	48.3	48.1
Generating capacity (GW)				
Coal	305	305	304	301
Hydro	110	110	110	110
Nuclear	102	102	102	102
Oil-natural gas	421	421	422	424
Other	12	12	12	12
Renewables	14	14	14	14
Total	964	964	964	963
Energy generation (thousand GWh)				
Coal	2,242	2,240	2,244	2,228
Hydro	296	296	298	297
Nuclear	811	811	811	811
Oil-natural gas	1,026	1,028	1,026	1,040
Other	67	67	67	67
Renewables	61	61	60	60
Total	4,503	4,503	4,506	4,503
Retrofits (cumulative GW, 2007-2020)				
FGD[a]	16.0	29.8	74.9	110.4
SCR[a]	33.3	35.8	75.5	111.0
SNCR	7.6	0.2	0.2	0.2
ACI[b]	0.3	0.2	0.2	0.2
Coal retirements and repowering (cumulative GW, 2007-2020)				
Repower to CC	0.9	0.9	0.9	0.9
Repower to IGCC	0.1	0.1	0.1	0.1
Coal retired	0.0	0.0	0.0	2.2
Oil-gas retired	42.0	41.7	41.5	40.6
Total	43.0	42.7	42.5	43.8
Coal production (million tons)				
Appalachia	315	316	354	364
Interior	162	183	243	260
West	631	603	496	468
Total	1,108	1,102	1,094	1,092
Total cost ($ billion 1999)	96.0	96.2	98.1	100.6

[a]IPM database assumes that 107 GW and 105 GW of coal-fired capacity are retrofitted with FGD and SCR, respectively, before 2007.

[b]Activated carbon injection, a mercury-control technology.

CCAIR-CAMR-BART			
ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
4,992	4,994	5,119	4742
1,994	1,994	1,994	1850
2,569	2,568	2,575	2,590
31.9	31.9	32.3	29.9
299	299	300	301
110	110	110	110
102	102	102	102
426	426	425	425
12	12	12	12
14	14	14	14
963	963	963	964
2,194	2,194	2,202	2,222
294	293	294	296
811	811	811	811
1,072	1,072	1,064	1,046
67	67	67	67
61	61	61	61
4,499	4,498	4,499	4,503
88.3	88.1	86.6	110.3
70.6	70.6	74.0	110.8
0.3	0.3	0.2	0.2
2.7	2.7	2.4	2.4
0.9	0.9	0.9	0.9
0.1	0.1	0.1	0.1
4.7	4.6	3.6	2.4
41.2	41.1	40.9	41.1
46.9	46.7	45.5	44.5
310	309	312	341
194	194	194	224
568	568	570	514
1,072	1,071	1,076	1,079
100.4	100.4	100.3	101.5

TABLE 6-6d Detailed Results of IPM Simulations for Year 2020

Other Regulations:	Title IV and NO_x SIP Call			
Lower Bound on R/R/R (%/yr increase)	ERP (0%)	Prerevision NSR "Low" 2%	Prerevision NSR "Middle" 5%	Prerevision NSR "High" 7.5%
National emissions				
SO_2 (million short tons)	8,876	8,862	8,787	3,632
NO_x (million short tons)	3,758	3,445	2,760	2,041
CO_2 (million metric tons)	2,796	2,797	2,797	2,799
Hg (short tons)	50.2	49.1	48.1	40.7
Generating capacity (GW)				
Coal	326	325	323	321
Hydro	110	110	110	110
Nuclear	103	103	103	103
Oil-natural gas	467	468	470	471
Other	12	12	12	12
Renewables	14	14	14	14
Total	1,032	1,032	1,032	1,031
Energy generation (thousand GWh)				
Coal	2,410	2,411	2,396	2,388
Hydro	294	295	295	295
Nuclear	809	809	809	809
Oil-natural gas	1,221	1,221	1,237	1,244
Other	54	54	54	54
Renewables	61	61	60	60
Total	4,849	4,851	4,851	4,850
Retrofits (cumulative GW, 2007-2020)				
FGD[a]	17.1	48.7	122.1	181.1
SCR[a]	35.8	49.2	122.8	181.4
SNCR	8.4	0.2	0.2	0.2
ACI[b]	0.3	0.2	0.2	0.2
Coal retirements and repowering (cumulative GW, 2007-2020)				
Repower to CC	0.9	0.9	0.9	0.9
Repower to IGCC	0.1	0.1	0.1	0.1
Coal retired	0	0	0	2.2
Oil-gas retired	42	41.7	41.5	40.6
Total	42	42.7	42.5	43.8
Coal production (million tons)				
Appalachia	301	336	383	392
Interior	173	227	275	269
West	714	600	495	505
Total	1,188	1,163	1,152	1,166
Total cost ($ billion 1999)	109.4	110.2	114.5	119.3

[a]IPM database assumes that 107 GW and 105 GW of coal-fired capacity are retrofitted with FGD and SCR, respectively, before 2007.

[b]Activated carbon injection, a mercury-control technology.

CAIR-CAMR-BART			
ERP (0%)	Prevision NSR "Low" 2%	Prevision NSR "Middle" 5%	Prevision NSR "High" 7.5%
4,282	4,279	4,126	3,399
2,002	2,002	1,763	1,312
2,758	2,758	2,772	2,789
28.7	28.7	27.6	26.8
321	321	320	320
110	110	110	110
103	103	103	103
472	472	472	473
12	12	12	12
14	14	14	14
1,032	1,032	1,031	1,032
2,358	2,357	2,373	2,375
292	292	294	295
809	809	809	809
1,272	1,273	1,258	1,257
54	54	54	54
61	61	61	61
4,846	4,846	4,849	4,851
107.9	108.1	120.3	181
72.9	72.9	120.9	181.3
0.5	0.5	0.2	0.2
11.1	11.1	5	4.7
0.9	0.9	0.9	0.9
0.1	0.1	0.1	0.1
4.7	4.6	3.9	2.4
41.2	41.1	40.9	41.1
46.9	46.7	45.8	44.5
330	330	343	398
225	226	246	286
568	568	536	463
1,123	1,124	1,125	1,147
115.6	115.5	116.3	120.5

in the "high" scenario. Only NO_x emissions fall more than about 1-2% below the cap at that level of control. As mentioned, the committee regards the "high" case as an unlikely high level of emission-control retrofit, so it does not regard the 2020 SO_2 reductions in that scenario as being likely outcomes of the prerevision NSR rule. However, because NO_x reductions occur under a less extreme "middle" scenario, we regard the possibility of NO_x increases associated with the ERP as being plausible, given the present Title IV and NO_x SIP call caps.[17]

The different conclusions concerning national NO_x and SO_2 emissions are due in part to the greater flexibility that generators have in ways to adjust (either reduce or increase) SO_2 emissions than they have for NO_x and in part due to the more comprehensive nature of SO_2 regulation in the absence of CAIR. SO_2 emissions can be adjusted either by switching to grades of coal with different sulfur contents or by installing postcombustion controls. Once a scrubber is installed, a coal-fired generator that previously burned low-sulfur coal may switch to less expensive higher-sulfur coal to keep its costs down, thereby limiting the ultimate effect of the retrofit on total emission of SO_2 from the facility.[18] For NO_x, the options are typically more limited. Once an SCR is installed, the associated reduction in the NO_x emission rate will not be partly or wholly offset by a change in fuel choice. In the absence of CAIR, the seasonal, regional NO_x cap-and-trade program under the NO_x SIP call is both geographically and temporally less comprehensive than the national annual SO_2 cap-and-trade program under Title IV. Thus, a smaller percentage of total NO_x emissions from the electricity sector are subject to a cap than the nearly 100% of SO_2 emissions that come under a cap.

We turn now to the analysis under the tighter caps under CAIR-CAMR. Considering the various R/R/R scenarios, the 2%/year and 5%/year simulations indicate that except for NO_x in the year 2020 national emissions are not pulled below the caps. NO_x falls 10% below the cap in 2020 in the 5%/year scenario; considerably less than if only Title IV and the NO_x SIP call were in place. Under the most extreme prerevision NSR case ("high," 7.5%/year R/R/R, involving almost 100% of coal capacity by 2020), SO_2 emissions fall below the cap slightly in 2015 and then by 20% in 2020. The tonnage of SO_2 in 2020 in that case is nearly the same as in the Title IV "high" R/R/R case (3,400 kT/year versus 3,600 kT/year). That is not

[17] A perhaps surprising result is that the R/R/R solutions that involve more scrubbing did not appreciably lower mercury emissions. A possible explanation is that increased scrubber installation was accompanied by additional consumption of higher-sulfur and higher-mercury coals.

[18] SIPs may also limit emissions or fuel choice at individual power plants, and this would decrease flexibility. EPA has informed us that the IPM model includes such limitations.

surprising, in that the caps in both cases are no longer effective, and practically all coal-fired capacity has scrubbers and SCR.

To get a sense of where emission reductions are occurring, we look at SO_2 and NO_x emission changes under the different R/R/R scenarios at CAIR-affected model plants and plants not affected by CAIR.[19] The model results indicate that most of the NO_x emission reductions with the R/R/R "high" scenario (given CAMR-CAIR) occur at non-CAIR-affected units, although in 2020 emissions from CAIR-affected units are reduced as well. For SO_2, the emission reductions in 2015 under the "high" scenario occur at CAIR-affected model plants, and emission reductions in 2020 are split between CAIR-affected and non-CAIR-affected model plants.

Although the committee has determined that the "high" scenario is an unlikely outcome of the prerevision NSR EPA RMRR policy, it does illustrate some interesting interactions of this type of rule with emission caps. In particular, what is surprising is that the SO_2 decrease in 2015 and 2020 in the "high" scenario (given CAMR-CAIR) is matched almost ton for ton by increases in 2007 and 2010. Thus, total emissions over the entire time horizon remain at or very near the cap. As the amount of scrubbing increases in later years, the price of emission allowances falls. If generation owners anticipate that development in earlier years, they will have weaker incentives for making early reductions in emissions and then banking the allowances for later use. The diminished value of banked allowances does not justify the marginal cost of fuel-switching, emission dispatch,[20] and other nonscrubbing emission-reduction measures in the early years.[21] Thus, the main effect of the "high" (7.5%/year) R/R/R constraint has been to redistribute SO_2 emissions over the period 2007-2020, not to reduce the total. If marginal health and other damages are increasing with emissions and any positive discount rate is used to evaluate damages, this redistribution cannot be viewed as a good outcome. However, it is possible that emissions in 2025 and later will be lower under the "high" scenario than under that base case

[19]Note that CAIR-affected units include all units that are subject to the annual CAIR rule for SO_2 or NO_x. Generators with less than 25 MW of capacity in the CAIR region are classified and not affected by CAIR, so their emissions are lumped in with those of generating units outside the CAIR region. Given that these units are small, this classification should not dramatically affect our locational conclusions.

[20]The *emissions dispatch* refers to the reordering of the dispatch of generation units in such a way that more generation comes from cleaner units with higher fuel costs and less from higher-emitting, cheaper units. Such reordering automatically occurs if dispatch orders are constructed in light of the opportunity cost of emission allowances, as well as fuel costs. Lower allowance prices will therefore result in less such emission dispatch. A number of studies have shown that emission dispatch makes an important contribution to emission reductions strategies of electricity-generating facilities (e.g., Heslin and Hobbs 1991; Jackson et al. 1993).

[21]Fuel contracts may somewhat constrain what changes in dispatch and fuels are possible, which may act to moderate the swings in emissions shown here.

and remain there, so damages in the long term might be less in the presence of that constraint. However, such a conclusion would need to assume that emission caps are not tightened after 2020; the likelihood of that cannot be assessed by this committee.

In contrast, the changes in NO_x emissions in the "high" scenario under CAIR-CAMR present no such ambiguity. There are no emission increases in earlier years relative to the base case, and emissions fall by 7% in 2015 and 34% in 2020. Thus, in the bounding case where nearly every coal-fired generator is assumed to be compelled by settlement or economics to be R/R/R by 2020 and there is assumed to be no change in the CAIR caps, there are NO_x emission benefits of the prerevision NSR rules relative to the ERP. Those benefits largely or completely disappear if what this committee considers to be more likely rates of R/R/R occur (0%, 2% "low," or 5%/yr "middle").

One indication of the effectiveness of economic incentives to lower SO_2 and NO_x emissions is revealed by comparing the "high" scenarios under Title IV-NO_x SIP call and under CAIR-CAMR. For instance, those two solutions have similar amounts of FGD retrofits in every year, because the SO_2 R/R/R constraint is binding in both cases in each year. However, a comparison of the SO_2 graphs in Figures 6-1 and 6-2 shows that they have very different amounts of emissions in 2007-2015. The use of fuel switching and fuel blending under CAIR-CAMR results in SO_2 emissions that are nearly 30% less than the Title IV-NO_x SIP call results in 2007 and 2010 and 46% less in 2015. The story is similar for NO_x emissions: the amount of SCR installations is essentially the same in each year, but emissions in the CAIR-CAMR case are 70% of those in the Title IV-NO_x SIP call simulation for 2010 and later (compare the NO_x graphs in Figures 6-1 and 6-2).

These are two reasons for these solutions to have similar emission-control retrofits but different emissions. First, the higher price of NO_x and SO_2 allowances in the CAIR-CAMR cases motivates installation of the control retrofits at locations where the emission controls are most cost effective. That is consistent with the idea that under the CAIR caps one would expect the NO_x controls to be installed first at the plants that can achieve the most cost-effective reductions. However, with only the type of rule used for NSR, controls might instead be installed at plants with low installation and operation costs per megawatt and not necessarily where the costs per ton of reductions are lowest. Second, allowance costs also motivate the adoption of fuel-switching and emission-dispatch strategies that can cost-effectively reduce emissions at generating units that are not retrofitted with FGD or SCR. In general, the least costly way of achieving an emission target involves a mix of emission-control investments, fuel-switching, and operational changes (Heslin and Hobbs, 1991). Strategies, such as the emission-control retrofits required by NSR settlements, can be relatively inefficient because they provide no incentives to adopt such combination strategies. Cap-based policies, in contrast, create a level playing field among alternative means of reducing emissions.

Sensitivity Analysis

As mentioned above, we have rerun the R/R/R "high" solution under CAIR-CAMR using alternative assumptions concerning the cost of alternative generation technologies. In particular, we are testing whether substantially lower natural gas prices or lower investment costs for renewables (wind, solar, landfill gas, biomass, and geothermal) and integrated gasification combined-cycle generation (IGCC) could affect our conclusions by pulling emissions below the cap earlier or by a larger amount. Table 6-7 compares that R/R/R "high" solution under base case investment and gas-cost assumptions with a R/R/R "high" solution that has lower renewable and IGCC investment costs ("low capital") and a second R/R/R "high" sensitivity case that, in addition, has much lower natural gas prices ("low capital-gas").

Considering first the sensitivity analysis involving lower investment costs for renewables and IGCC, we conclude that those assumptions make almost no difference in emission, generation mix, and emission controls, at least through 2020. Renewable generation capacity goes up by about 15% in 2020, but because this is from a small base (14 GW, less than 5% of the amount of coal capacity), there is negligible effect on emissions. There is no additional repowering to IGCC, but new IGCC rises from 6.9 GW to 12.2 GW by 2020 (about 3% of total coal capacity). The latter displaces some other types of capacity additions that occurred in the base R/R/R "high" case but does not appreciably affect total system emissions.

A greater effect on emissions occurs in the second sensitivity analysis (low gas cost and low renewables and IGCC investment cost). SO_2 emissions fall by about 3% in 2020, although the total 2007-2015 SO_2 emissions are essentially unchanged, as are 2007-2020 NO_x emissions. The fall in SO_2 emissions occurs because natural gas energy generation expands by 15% (compared with the R/R/R "high" case), mainly at the expense of coal generation. Natural gas capacity increases by 25 GW compared with the R/R/R "high" case, and the increase is matched by an identical decrease in coal capacity. Thus, a mix of generation, especially new plant additions, is somewhat sensitive to gas prices and investment cost assumptions. However, the basic conclusion—that SO_2 emissions are pulled slightly below the CAIR-CAMR cap by 2020 only if all existing unscrubbed capacity is retrofitted with scrubbers and that NO_x emissions would be pulled below the CAIR cap in 2015 only if nearly all coal capacity is retrofitted with SCR—is unaffected.

TABLE 6-7 Sensitivity Analyses of R/R/R Case: Lower Capital Costs for Renewables and IGCC and Lower Natural Gas Prices

Variable	Solution	2007	2010	2015	2020
National emissions					
SO_2 (thousand tons)	R/R/R "high"	8,756	6,967	4,742	3,399
	Low capital	8,743	6,974	4,735	3,406
	Low capital-gas	8,782	7,011	4,674	3,292
NO_x (thousand tons)	R/R/R "high"	3,629	2,438	1,850	1,312
	Low capital	3,628	2,441	1,859	1,329
	Low capital-gas	3,611	2,430	1,873	1,307
CO_2 (million tons)	R/R/R "high"	2,380	2,453	2,590	2,789
	Low capital	2,378	2,451	2,600	2,822
	Low capital-gas	2,374	2,418	2,556	2,707
Hg (tons)	R/R/R "high"	49	37	30	27
	Low capital	49	37	30	27
	Low capital-gas	49	37	30	26
Retrofits (cumulative GW from 2007)					
FGD	R/R/R "high"	8.0	39.6	110.3	181
	Low capital	8.0	39.0	109.7	179.2
	Low capital-gas	8.0	34.4	104.9	175.3
SCR	R/R/R "high"	18.8	43.7	110.8	181.3
	Low capital	18.6	43.2	110.1	179.3
	Low capital-gas	18.2	37.7	104.8	175.0
Coal retirements and repowering (cumulative GW, 2007-2020)					
Repower to CC	R/R/R "high"	0.0	0.9	0.9	0.9
	Low capital	0.0	0.9	0.9	0.9
	Low capital-gas	0.0	0.9	0.9	0.9
Repower to IGCC	R/R/R "high"	0.0	0.1	0.1	0.1
	Low capital	0.0	0.1	0.1	0.1
	Low capital-gas	0.0	0.0	0.1	0.1
Coal retired	R/R/R "high"	2.3	2.4	2.4	2.4
	Low capital	3.0	3.1	3.1	4.4
	Low capital-gas	7.2	8.4	9.0	9.4
Oil/gas retired	R/R/R "high"	40.5	41.1	41.1	41.1
	Low capital	40.5	41.0	41.0	41.0
	Low capital-gas	33.2	33.4	33.4	33.4
Energy generation (thousand GWh)					
Coal	R/R/R "high"	2,144	2,173	2,222	2,375
	Low capital	2,142	2,171	2,253	2,475
	Low capital-gas	2,134	2,118	2,161	2,189
Oil/natural gas	R/R/R "high"	670	800	1,046	1,257
	Low capital	670	800	1,007	1,149
	Low capital-gas	679	852	1,107	1,441

TABLE 6-7 Continued

Variable	Solution	2007	2010	2015	2020
Renewables	R/R/R "high"	54	56	61	61
	Low capital	56	58	69	69
	Low capital-gas	55	58	60	61
Generating capacity (MW)					
Coal	R/R/R "high"	302	302	301	320
	Low capital	302	301	305	334
	Low capital-gas	297	296	294	295
Oil/natural gas	R/R/R "high"	387	394	425	473
	Low capital	387	394	419	458
	Low capital-gas	396	402	431	498
Renewables	R/R/R "high"	13	13	14	14
	Low capital	13	14	16	16
	Low capital-gas	13	14	14	14

Economic Efficiency of Different Approaches to Reducing National or Regional Emissions

To assess the potential efficiency of the R/R/R variants of the prerevision NSR RMRR, we have calculated cost effectiveness in dollars per ton for each R/R/R case against its base case for both the Title IV-NO_x SIP call and the CAIR-CAMR emission cap scenarios. That is, given a set of emission caps, what is the cost per ton of emission reduction? For simplicity, the reductions include both the NO_x and SO_2 effects, assuming that they get equal weight in the calculation. Costs and emissions from 2007 through 2020 are considered; values for years between the solutions for 2007, 2010, 2015, and 2020 are obtained by linear interpolation. Table 6-8 shows the calculations for two assumptions about discounting emissions: one with a zero discount rate and the other with a 5%/year real discount rate. The former assumes that a ton of emissions in 2020 should be weighted just as much as a ton emitted today. The latter is more consistent with a levelized emission-costing approach.[22]

[22]A levelized cost-effectiveness number is interpreted as follows: if the actual cost per ton of reduction were the same in every year and equal to the levelized value, the present worth of costs would be identical with the present worth of the actual distribution of costs. For instance, at a 10% interest rate, reducing 1,000 tons in year 1 (at a cost of $200/ton) and 1,500 tons in year 2 (at a cost of $250/ton) has a present worth of $(1,000)(200)/1.1 + (1,500)(250)/1.1^2$ = $491.736. If instead the cost per ton was $228,846/ton in both years, the present worth would also be $491,736 = $(1,000)(228.846)/1.1 + (1,500)(228.846)/1.1^2$. Thus, $/ton is the "levelized" per-ton cost that is equivalent, in a present-worth sense, to the actual distribution of costs.

TABLE 6-8 Cost Effectiveness of Emission Reductions for Various Cases Compared to Base Cases

Case	Undiscounted Emission Analysis			
	Undiscounted SO_2 Emissions, 2007-2020 (thousands of tons)	Undiscounted NO_x Emissions, 2007-2020 (thousands of tons)	Total Discounted Cost (billion of $)[a]	Cost Effectiveness ($/ton)
Comparison of R/R/R cases with Title IV-NOx SIP call base case				
Base case (Title IV-NO_x SIP call)	132,430	51,930	867.2	
Title IV-SIP with "low" R/R/R (2%)	132,250	49,140	869.7	$850
Title IV-SIP with "middle" R/R/R (5%)	133,150	45,670	882.8	$2,800
Title IV-SIP with "high" R/R/R (7.5%)	118,670	41,150	899.1	$1,300
Comparison of R/R/R cases with CAIR-CAMR base case				
Base case (CAIR-CAMR)	79,520	32,960	900.9	
CAIR-CAMR with "low" R/R/R (2%)	79,530	32,960	900.9	negative
CAIR-CAMR with "middle" R/R/R (5%)	79,910	32,250	901.8	$2,900
CAIR-CAMR with "high" R/R/R (7.5%)	79,280	30,200	910.1	$3,100
Comparison of CAIR-CAMR base case with Title IV-NOx SIP call base case				
Base case (Title IV-NO_x SIP call)	132,430	51,930	867.2	
Base case (CAIR-CAMR)	79,520	32,960	900.9	$470
Comparison of minimal cost solution for achieving "CAIR-CAMR with 'high' R/R/R (7.5%)" emissions reductions with CAIR-CAMR base case				
Base case (CAIR-CAMR)	79,520	32,960	900.9	
Minimal cost solution	79,314	29,289	904.6	$960

[a]5% discount rate used, discounted to 2005; $1999 assumed for costs. The discounted costs columns are the same for both the discounted and undiscounted emissions analysis.

Discounted Emissions Analysis			
Discounted SO_2 Emissions, 2007-2020 (thousands of tons)	Discounted NO_x Emissions, 2007-2020 (thousands of tons)[a]	Total Discounted Cost (billion of $)[a]	Cost Effectiveness, Levelized ($/ton)
90,090	34,910	867	
90,140	33,190	870	$1,500
91,110	31,250	883	$5,900
84,130	28,640	899	$2,600
55,670	23,010	900.9	
55,670	23,010	900.9	negative
56,000	22,650	901.8	$53,000
56,450	21,530	910.1	$13,000
90,090	34,910	867.2	
55,670	23,010	900.9	$730
55,670	23,010	900.9	
56,422	20,831	904.6	$2,600

The table shows that the incremental emission reductions (relative to the Title IV-NO_x SIP call base case) achieved by imposing the R/R/R constraint cost \$850-5,900 per ton.[23] Given the CAIR-CAMR emission reductions, the incremental cost of further R/R/R emission reductions would be between \$2,900 and \$53,000 per ton. For the "low" (2%) constraint case with CAIR-CAMR, the emission "reduction" is actually negative (emissions increase slightly over the 2007-2020 period), so the cost effectiveness is negative. These costs per ton of reduction are large compared with the costs of achieving emission reductions by using a cap alone, discussed next.

The cost of achieving emission reduction with a cap is gauged in two ways. First, we compare the two base cases in the third group of rows of Table 6-8. Both of those solutions assume that the ERP is in place (that is, the R/R/R constraint is omitted). That calculation shows that the cost effectiveness of the emission reductions resulting from replacing the Title IV-NO_x SIP call with the CAIR-CAMR cap is \$470/ton (undiscounted) to \$730/ton (discounted). The most relevant comparisons are the R/R/R cost-effectiveness estimates with the Title IV-NO_x SIP call base case, which yields cost-per-ton estimates (\$850-\$5,900/ton) that are 2-8 times as high as the corresponding cost-effectiveness estimate for the CAIR-CAMR cap by itself (\$470-\$730/ton). That is again not unexpected, inasmuch as the R/R/R scenario as implemented in IPM requires specific technologies at selected plants versus economic optimization as the basis for the CAIR-CAMR controls.

However, this comparison is something of an apples-versus-oranges comparison because the emission reductions involved are not identical. Therefore, we gauge whether the cost per ton of reduction in the R/R/R scenario is large in a second way: by comparing that cost with the expense per ton of achieving the same reductions with use of caps alone. To do that, IPM with the CAIR-CAMR base case assumptions was run with an additional set of constraints forcing SO_2 and NO_x emissions in each of the solution years to be less than or equal to the corresponding emissions obtained by the R/R/R. That is termed the "minimal cost" solution because IPM achieves those solutions at the lowest cost under the assumption that national caps with tradable rights are imposed. In the last two rows of Table 6-9 we compare that solution with the CAIR-CAMR base case.[24]

[23]The undiscounted emission values are smaller because the emission denominator of the cost-effectiveness calculation is larger if emissions are not discounted. Another reason is that, in some cases, there are emission increases in early years followed by emission decreases; the latter are discounted more than the former.

[24]The emission reductions are not precisely the same because of modeling approximations; the minimal cost solution has about 10% less NO_x emission in 2010 and 1.5% more SO_2 emission in 2020. We did not allow banking of the national cap allowances in our minimal cost solution. If such a policy were implemented, however, banking would probably redistribute the assumed emission reductions differently over time.

TABLE 6-9 Comparison of R/R/R "High" Solution (prerevision NSR RMRR) with Minimal-Cost Solution That Achieves Same Emissions

Year	Solution	2007	2010	2015	2020
National emissions					
SO_2 (thousand tons)	R/R/R "high"	8,756	6,967	4,742	3,399
	Minimum cost	8,692	6,967	4,742	3,452
NO_x (thousand tons)	R/R/R "high"	3,629	2,438	1,850	1,312
	Minimum cost t	3,617	2,215	1,851	1,314
CO_2 (million tons)	R/R/R "high"	2,380	2,453	2,590	2,789
	Minimum cost	2,377	2,447	2,561	2,735
Hg (tons)	R/R/R "high"	49	37	30	27
	Minimum cost	49	37	30	27
Retrofits (cumulative GW from 2007)					
FGD	R/R/R "high"	8.0	39.6	110.3	181.0
	Minimum cost	8.0	35.2	94.2	127.3
SCR	R/R/R "high"	18.8	43.7	110.8	181.3
	Minimum cost	18.4	40.9	74.3	129.3
SNCR	R/R/R "high"	0.2	0.2	0.2	0.2
	Minimum cost	0.2	0.4	0.9	4.1
ACI	R/R/R "high"	0.0	1.7	2.4	4.7
	Minimum cost	0.0	1.3	5.1	5.1
Coal retirements and repowering (cumulative GW, 2007-2020)					
Repower to CC	R/R/R "high"	0.0	0.9	0.9	0.9
	Minimum cost	0.0	0.9	0.9	0.9
Repower to IGCC	R/R/R "high"	0.0	0.1	0.1	0.1
	Minimum cost	0.0	0.1	0.1	0.1
Coal retired	R/R/R "high"	2.3	2.4	2.4	2.4
	Minimum cost	4.7	5.2	5.2	6.2
Oil/gas retired	R/R/R "high"	40.5	41.1	41.1	41.1
	Minimum cost	40.5	41.3	41.3	41.3
Coal production (million tons)					
Appalachia	R/R/R "high"	312	315	341	398
	Minimum cost	308	310	313	346
Interior	R/R/R "high"	142	164	224	286
	Minimum cost	142	159	199	229
West	R/R/R "high"	617	587	514	463
	Minimum cost	618	592	549	526
National	R/R/R "high"	1,071	1,066	1,078	1,147
	Minimum cost	1,068	1,061	1,062	1,101
Total cost ($ billion 1999)					
	R/R/R "high"	81.84	87.86	101.50	120.47
	Minimum cost	81.83	87.86	100.98	117.95

The cost effectiveness of the minimum-cost reductions is \$960/ton (undiscounted emissions) and \$2,600/ton (discounted) for about the same emission reductions as the R/R/R "high" case.[25] Those costs are one-third and one-fifth, respectively, of the cost of the same emission reductions relative to the CAIR-CAMR base case obtained by instead relying on the previous RMRR, assuming the extreme R/R/R "high" case (\$3,100 and \$13,000, see Table 6-8). The reason why the prerevision RMRR is not a cost-effective way to achieve national emission reductions is evident in Table 6-9, which contrasts the costs, emissions, technology, and fuel results for the minimal cost and R/R/R "high" solutions. The minimal cost solution is \$2.5 billion per year less expensive by 2020, although its SO_2, NO_x, CO_2, and mercury emissions are no more, and sometimes less, than the R/R/R "high" case. The reason is that the minimal cost solution retrofits less FGD and SCR (30% less in 2020) while using more western low sulfur coal (14% more in 2020) and natural gas and SNCR to achieve the target reductions.[26]

Those results reinforce the conclusion we drew above: a constraining control strategy (only allowing plants to retrofit, repower, or retire, and plants not selected using market forces) by itself gives sources less flexibility. By not allowing trading, sources are deprived of the opportunity to arrive at lowest-cost solutions (see NRC 2004), and it would be more expensive to achieve the same national emission reductions.

MODEL ASSUMPTIONS AND LIMITATIONS

This modeling exercise uses Version 2.1.9 of the ICF IPM released in 2004.[27] As mentioned in Chapter 4, IPM is a deterministic model of the electricity sector that uses linear programming techniques to find a lowest-

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[25]In reality, because of frictions in the market and the effects of public electricity-generating facility regulation on generator behavior, the actual costs of a trading program are likely to be higher than the costs predicted by the model. Indeed, work by Sotkiewicz and Holt (2005) and Carlson et al. (2000) suggests that the true costs under a trading regime could be as much as 50% higher than the true lowest cost. Nevertheless, a large gap between the cost per ton of the high R/R/R and a more realistic estimate of the cost per ton with trading remains.

[26]As Figure 6-7 shows, the amount of scrubbing in the minimal cost solution is 19 GW more than the CAIR-CAMR base case, but 54 GW less than in the R/R/R "high" solution. (See also Tables 6-6d and 6-9.) Total coal capacity is 2 GW less in the minimal-cost scenario, and coal generation is 2% less, with the energy difference made up by natural gas. As Table 6-9 indicates, of the 110,000-ton reduction in bituminous- and subbituminous-coal use, slightly more than half is made up by an increase in western-coal use (by tonnage). The rest is made up by an increase in natural-gas generation. Under the higher natural gas prices that are now forecast, the likely outcome is that western coal would make up much more of the reduction in bituminous and subbituminous coal use.

[27]For more information about the data requirements and limitations of the IPM model, see EPA (2004g).

cost approach to determine the dispatch of electricity-generating facilities to meet projected electricity demand and the amounts and types of generating-capacity investment and retirement sufficient to meet peak demands and regional reserve requirements. The model divides the continental U.S. electricity sector into 26 regions and allows for interregional power trading within the bounds of interregional transmission capacity and subject to an average representation of transmission losses. The model incorporates regulatory restrictions on emissions of air pollutants from electricity-generating plants. When flexibility is allowed, as in the case of a cap-and-trade program, IPM finds the lowest-cost approach to comply with those restrictions.

IPM is a highly parameterized optimization model that requires assumptions regarding the representation of decision making in the industry, values of important parameters, and relevant environmental policies and enforcement actions. Many of the assumptions are listed in Table 6-10. Most of these limiting assumptions are shared by other national power-sector models and, therefore, the resulting limitations are also shared. EPA has subjected IPM's input assumptions to extensive stakeholder and peer review and has conducted validation tests of IPM short-term outputs. EPA reports that these indicate that IPM can closely approximate electricity-generating sector operations.[28]

In reading our discussion of individual assumptions and limitations, we ask the reader to keep in mind the adage that "all models are wrong, but some are useful." Models are generally a simplification of reality, but they can still provide useful insights about the general response of a system (in this case, the power sector's response to a change in NSR rules under alternative-policy backdrops). It is certainly possible that the assumptions about prices, load growth, other policies, or investor behavior will be so wrong that even the qualitative behavior of the model projections will be badly misleading.

[28]In response to a committee request, EPA has described the input reviews and output validity tests it has conducted. Because IPM has been used to support the development of regulations, extensive external reviews by stakeholders and contractors of assumptions concerning general economic conditions, fuel supply, load growth, representation of air regulations, and generator characteristics have been made. Validation studies have included comparisons of IPM dispatch simulations with actual 2001 generation and emission data, and EPA indicated that projected values for most plant types were within 10% of actual values. EPA reported that it regularly compares other key model outputs (such as fuel consumption by type, plant output by type, interregional transmission flows, and prices) to historical levels, and when discrepancies occur, model inputs and structure are evaluated and modified. EPA also indicated that evaluations have been performed of IPM's ability to project significant events in the power market. For instance, 1996 runs of IPM—when SO_2 allowances prices were approximately \$75/ton—projected prices would rise to about \$200 by the year 2000, which indeed they did. More recent market projections correctly anticipated plant mothballing decisions in Texas and California. IPM has also been subjected to review by many other IPM users in both the public and private sector (personal communication, M. Victor, EPA, May 2006).

TABLE 6-10 Limitations and Key Assumptions of the Integrated Planning Model

IPM Structural Elements	Notes
Perfectly inelastic electricity demand	
Perfectly competitive regional electricity markets	
Regional configuration of national electricity system with no intraregional transmission constraints[a]	
Perfect foresight	No explicit treatment of uncertainty in modeling; presence of uncertainty and risk-averse behavior could affect decisions
Forecast horizon to 2026 only	Could affect investment choices and value of banked allowances
Operation and maintenance costs linear with respect to generation (variable) and capacity (fixed)	No explicit treatment of component replacement decisions; impossible to model NSR constraints explicitly
Generating plants aggregated to representative model plants	Limits ability to represent heterogeneity of full fleet of generators
Operations and capital investments chosen to minimize cost subject to policy, technical, and demand constraints	Assumes that average-cost-based regulation or deregulation do not result in systematic biases away from cost-minimizing decisions
Long-term contracts assumed to be no barrier to fuel switching	Could overstate flexibility and therefore attractiveness of fuel switching as an abatement option
Parameters	
Fuel prices and supply schedules for coal and natural gas	Gas-price assumption varied in sensitivity analysis
Heat content and sulfur and mercury content of different types of coal	
Heat rates of existing generators	Varied in "avoid" variant of ERP
Capacity of existing generators	Varied in "avoid" variant of ERP
Forecasts of electricity demand	
Shape of load-duration curves	
Interregional transmission constraints	
Capital costs for new generating units	Varied in sensitivity analysis
Operating and maintenance costs at existing units	Varied in "avoid" variant of ERP
Costs and performance of pollution-control retrofits	
Regional reserve-margin requirements	
Policy assumptions	
Federal environmental constraints	Varied in sensitivity analysis
State pollution-control policies	
Policies to promote renewables	
Past NSR settlements and allowance surrenders	

[a]For this reason and because of generic cost and technology characterizations, IPM is not generally appropriate for modeling changes in outputs from individual generating units.

However, given the extensive reliance that EPA and others have had with IPM-type models and how useful they have been in projecting the qualitative effects of previous policy changes, the committee concludes that IPM is the only practical tool available at this time to explore the impacts of different scenarios concerning the effects of the NSR rule changes.

Several structural assumptions have important implications for the results of this analysis. First, to simulate the operation and capital investments for thousands of power plants over multiple hours in multiple years, computational limitations required that existing generating capacity must be aggregated into model plants. Even with this aggregation, the number of decision variables in IPM is typically on the order of five million, which is exceptionally large for linear programming models. For coal-fired boilers, the grouping of units is more detailed than for other types of generators, so each model coal plant represents roughly two existing generating units. However, aggregation means that the model will not provide direct results for generation or emissions at the unit or plant level. Second, as discussed above, the model does not include an explicit representation of maintenance or life-extension options and their costs or effects on unit performance. Plant operating and maintenance (O&M) costs are rolled together and represented as a linear function of total capacity (for fixed O&M) or of total generation (for variable O&M). As a result, it is difficult to analyze directly the effects of NSR rule changes on these types of investments, and we must do it through the scenario-based approach described above and summarized in Table 6-4. Third, the model assumes that all electricity-generating facilities have perfect foresight with respect to changes in electricity demand, prices, fuel and other costs, and environmental policies. Thus, the model is unable to reflect decisions that generators that do face uncertainty might make to limit the effects of possible adverse outcomes.[29] Also, because the model is deterministic, there is no variation in output associated with a set of model inputs. Furthermore, neither error bounds nor standard errors have been estimated for model parameters. These components of uncertainty are not estimatable at this time. Sensitivity analysis, that is, varying inputs over a "reasonable" range and assessing the variation in outputs will document the consequence of input uncertainty, but cannot capture variation for a fixed set of inputs that would result from a stochastic model. The probability distribution of outputs can be as important as the central value (policy might well be based on the 75th percentile of the emission distribution) and

[29]For example, because generators are likely to be risk-averse, banking additional allowances could provide a valued hedge against the possibility of much higher allowance prices in the future. Under uncertainty, generators might also prefer to defer investments, such as scrubbers, that limit options and instead rely more on fuel-switching and other reversible strategies (e.g., Hobbs et al. 1994).

are not available. Time and budgetary constraints limited the number of alternative scenarios that we could analyze, so we were unable to explore the full range of outcomes that might emerge in a more complete analysis that incorporated a wider range of assumptions about key inputs.

An important but less obvious consequence of using a deterministic model in a nonlinear system is the discrepancy between model output and the "average" output of a stochastic simulation (for example, Murphy et al. 1982). For example, for a particular regulatory scenario, outputs averaged over several runs based on different values of uncertain parameters or inputs can be far from the values reported by IPM. We do not know the magnitude of this discrepancy, but we provide the caution.

Another methodological limitation is related to how we model the R/R/R scenario for the prerevision NSR RMRR. This scenario assumes that the plants that have the lowest cost (including changes in fuel, emissions, and capital costs) of retrofitting with scrubbers or SCR units are the first to undergo NSR. However, it is possible, and perhaps very likely, that NSR enforcement would target plants at which emission reductions would be less cost effective. That would result in higher costs but possibly greater emission reductions than in the R/R/R solutions.

The lowest-cost assumption for choosing R/R/R scenarios was used because of modeling convenience; it could be implemented by adding a single constraint for each year to IPM. As sensitivity analyses, it would have been desirable if other procedures for choosing units for R/R/R could have been simulated. Examples include criteria based on size, age, or emission rates of units; selective targeting of units whose emissions would affect the greatest number of people; or a prioritizing of units having the largest effect on nonattainment regions. Because time limitations meant that it was not possible to generate such R/R/R scenarios, the committee cannot determine whether alternative assumptions concerning which units would be first subject to R/R/R would significantly affect the spatial distribution of emissions or even the total emissions. However, it should be noted that a criterion that would focus on the largest units in terms of megawatts and emissions is likely to result in a pattern similar to the lowest-cost assumption, because retrofits would probably be the least costly for the larger units, considering both the capital expense and emission-allowance benefits of retrofits.

An additional methodological limitation was IPM's division of the national electricity market into 26 regions. As a result, restrictions on power trading and operations arising from intraregional constraints and institutional barriers, such as vertically integrated electricity-generating facilities, are not included in the model. The result is that IPM cost estimates are lower than would otherwise occur because the addition of intraregional constraints can only worsen the objective function of IPM (cost) or, at best, leave it unchanged. A further implication is that estimates of local emission changes will not be as reliable as estimates of shifts between regions. No unambiguous a priori expectation about biases in emissions is possible. A previous comparison of aggregated and disaggregated representations of the U.S. electricity market concluded that national and regional patterns of costs and CO_2 emissions are not significantly distorted by aggregation, although NO_x emission patterns show some larger differences (EIA 1999).[30]

Another way in which IPM simulation results could differ from actual decisions is that the patchwork of state regulation of electricity-generating facility prices and investment decisions could result in deviations of operating and investment decisions away from the cost-minimizing choices assumed by IPM. For instance, the greater ability of regulated vertically integrated electricity-generating facilities to pass on costs might, for instance, result in a bias towards capital-intensive choices (for example, because of the effect presented in Averch and Johnson [1962]). National-energy-market models have not accounted for such potential distortions, although they do represent the effect of different rate-setting mechanisms on consumer prices. Although the committee does not expect that national patterns of emissions would be significantly affected by this issue, there could be local effects. This provides another reason to be cautious about drawing conclusions regarding effects on spatial distributions of emissions from the IPM runs.

Another institutional factor that could cause real-world decisions to deviate from the IPM least-cost solutions is the presence of long-term fuel contracts. Conceivably, rigidities in coal contracts could prevent switching from high-sulfur to low-sulfur coal in early years and then a switch back when retrofits are made later, even if IPM indicates that is a lowest-cost strategy for complying with increasingly restrictive emissions limits. However, the committee does not expect coal contracts to be a large barrier for three reasons. First, the U.S. Energy Information Agency's Coal Transportation Rate Database indicates that the duration of coal contracts has shrunk significantly in the last decade. For instance, in 1999 and 2000, all new coal

[30]This comparison in the cited report involved the National Energy Modeling System (NEMS) and the Policy Office Electricity Modeling System (POEMS). NEMS has 13 regions, and POEMS includes 114 regions. Tables ES1, 5, and A1 of that report show year 2015 estimates under a reference case of 4065 billion kWh of sales, 2,207 billion kWh of coal-fired generation, 9,067 thousand short tons of SO_2 emissions, 710 million metric tons of carbon emissions, and an average electricity price of $60/MWh for POEMS. The corresponding numbers are 4,057 billion kWh, 2,192 billion kWh, 9,090 thousand short tons of SO_2 emissions, 711 million metric tons, and $59.1/MWh for NEMS. As would be expected, regional differences were larger on a percentage basis than national differences, but were relatively smaller in the eastern United States than in the West. NO_x emissions perhaps showed the largest variations, for instance with Table B2 showing 2015 NO_x emissions in the East Central Area Reliability Coordination Agreement (ECAR) amounting to 836 thousand short tons under POEMS but 911 thousand short tons under NEMS. Possible reasons for these differences were not discussed in the cited report.

contracts entered into by reporting electricity-generating facilities were of 5-year durations or shorter (Richard F. Bonskowski, U.S. Energy Information Agency, personal commun., 2006). Second, even if saddled with "take or pay" contracts for a particular coal type, it is possible to resell contracted coal on the liquid spot market, and replace it with a preferred type. Thus, long-term contracts could be viewed as sunk costs and may not greatly affect short-term choices. Third, a large amount of fuel switching occurred in Phase I of the Title IV SO_2 program, although coal contracts were of longer duration then and generators knew that the tighter Phase II limitations were soon to be in place.

Several of the parameters listed in Table 6-10 are varied in one or more of the ERP scenarios listed in Table 6-4. In its RIA of the ERP, EPA assumed that before the ERP generators would essentially avoid triggering NSR and that this would lead to deterioration in the performance of generating units. Such deterioration could include increases in heat rates, reductions in total capacity, and increases in operating and maintenance costs. The EPA analysis included several alternative assumptions for all those effects, and the effects on the resulting emissions were only around 1%. However, in the R/R/R alternative scenarios run for this report, we make no assumptions about changes in plant performance (other than those associated directly with the retrofit or repower) when it might be reasonable to expect improvements in performance as a result of the investment or maintenance activity that triggered NSR.[31] Such an omission could bias our estimates of the cost of the R/R/R scenarios upward.

As discussed above, we considered a sensitivity analysis to examine the potential effects of varying the costs of natural gas and the costs of new renewable technologies on our results. However, other assumptions regarding, for example, the cost and performance of pollution-control technologies could affect both the cost and emission reductions under the R/R/R cases. Those potential sensitivities are not explored here.

IPM also includes representations of various environmental policies, such as state-imposed emission caps on various pollutants, SIP limits on emission rates, and state renewable-generation requirements. As discussed above, we used scenario analysis to look at the effects of eliminating CAIR, the BART rule, and CAMR, and the results of that analysis are reported above. However, we did not consider the effects of varying those other environmental- and technology-regulation assumptions in the model.

A category of costs not considered by IPM or other models of the power sector is expenses associated with administration, litigation, and lobbying. These are difficult to estimate, in part, because of regulatory changes in the

[31]IPM assumes no deterioration in a coal-fired unit's efficiency or capacity over time except for an increase of $5,000/MW-year in fixed O&M costs if a plant is over 30 years old.

power industry. In particular, it can be argued that deregulated electricity generators have more incentive than vertically integrated electricity-generating facilities to resist EPA policies or enforcement efforts, because regulated entities can more easily pass on costs to ratepayers.

CONCLUSIONS

Methodology Conclusions

For this chapter, the committee used a structural, bottom-up model (IPM) of the power industry. We changed some assumptions of the model used by EPA in its RIA of the ERP (EPA 2003c, Appendix B) to represent a range of alternative hypotheses concerning the effect of the prerevision RMRR and ERP on decisions by electricity-generating facility owners to maintain, retrofit, repower, or retire their facilities. The committee cautions that economic, policy, and legal uncertainties are too large to determine which of these hypotheses is most likely to be correct, so we have adopted a scenario and bounding approach to explore the consequences of alternative assumptions.

The committee concludes that such an approach is useful for exploring the implications of alternative assumptions while imposing consistency conditions, such as the clearing of energy markets and compliance with emission caps, and considering interactions among different markets and policies. We found that, subject to the caveats we identify, the use of a sectoral simulation model has been helpful in providing some quantification of interactions of NSR with emission caps.[32]

[32]The effect of imposing market-consistency conditions on the emission projections is evident if one compares the methods and conclusions of this chapter's analysis with studies that quantify potential emission increase at power plants on a facility basis. An example is NESCAUM 2004, which focused, like this chapter, on the EPR. That report carefully considered potential emission increases at 308 Title V facilities in six states, computed on the basis of the difference between their allowable and actual emissions. The study computed the difference between actual emissions and those allowable on the basis of available permits for the 308 facilities for two cases, assuming that all plants operate at 85% of emitting capacity and that all plants operate at 100% of emitting capacity. For the 85% case, for example, it was determined that emissions from these facilities can increase (relative to 1999 actual emissions) by 95% for NO_x (130% at full capacity), 178% for SO_2 (227% at full capacity), and 272% for volatile organic compound (338% at full capacity). The report states that other air-pollution regulations are unlikely to limit potential emission increases associated with the new ERP effectively if they occur.

NESCAUM (2004) is careful to point out that its analysis does not purport to be a projection of increases that would occur. Such a projection would have to account for the sector-wide consistency conditions described in Chapter 4; the discussion of the NESCAUM report by Smith et al. (2004) focuses on this point. In particular, the amounts of increases that the

The EPA RIA assumed that under the prerevision NSR rules generation owners would choose to avoid NSR by deferring maintenance, and as a result facility performance would deteriorate. The committee has examined a broader array of scenarios concerning the possible reaction of the power industry to the prerevision NSR rules. In particular, we considered the possibility that the previous rules would have compelled a much greater amount of coal-fired capacity to retrofit controls, repower, or retire than the ERP. Although such an assumption was not considered in EPA (2003c), other parties in the NSR controversy have argued for the plausibility of such a consequence of the prerevision NSR rules. Depending on the stringency of emission caps, the committee's analysis shows that changing assumptions concerning industry response can alter the conclusions of a comparison of the two sets of rules.

Although the IPM simulation approach is useful for considering industrywide responses to the ERP change and analyzing their effects, the model is not sufficiently detailed to look at the effects of the rule change on local or even regional emissions. The aggregation of actual plants into model plants, the inability of IPM to represent plant-specific costs of life extension or maintenance, and the fact that NSR compliance activity may not follow the cost-minimizing algorithm adopted here are three of the key reasons, among many, why the model cannot be expected to predict how the rule changes might affect emissions or air quality in a particular locale. The committee also finds that the tools do not exist to provide a sufficient basis of conclusions as to whether implementation of the ERP would have an effect on local air quality. Although IPM and similar models have been used in regulatory impact analyses in the past, this has generally been in the context of large-scale national emission reductions, in which some of the above concerns would be relatively less significant. In settings in which the primary effect could be a redistribution rather than a large reduction of

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NESCAUM report indicates are possible for electricity-generating units are infeasible because of market constraints.

The relevant market constraints include electricity supply-demand balances and emission caps. A key feature of the supply-demand balance is that electricity is not storable, so it is not possible for all electricity generators to simultaneously operate at output levels over some period, because the ratio of average to peak electricity demand is around 60%. Consequently, although baseload generators will operate in the neighborhood of 90%, shutting down only for maintenance, a large fraction of generating capacity will be cycled, operating only about 50% of the time, and other capacity will produce only a few hours per year to meet peak loads. If a group of power plants greatly increases production, others elsewhere will be decreasing theirs. If the output increase occurs at plants with much higher emission rates than the facilities that are decreasing their output, total emissions of the industry could increase. However, that is not possible for SO_2 emissions, because of the Title IV cap, and it is also impossible for NO_x emissions in the 22 eastern states in the SIP call region during the ozone season because of that cap. CAIR would provide similar protection against increases in total emissions.

emissions, understanding the precise location of emissions would be critical for determining whether net public health benefits would be positive or negative, and this is beyond the scope of IPM or related models.

Substantive Conclusions

According to the IPM modeling approach, the potential effects of the ERP on national emissions from electricity-generating facilities will differ between SO_2 and NO_x and will depend on whether the CAIR rule is assumed to be in place. The effects will also depend in an important way on how electricity producers respond to the rule changes.

If all generators would have responded to the prerevision NSR rules by avoiding NSR requirements, as EPA assumed in its RIA, emissions would change very little in response to the ERP. In particular, the IPM results as used in the RIA indicate that there is a less than 1% change in emissions of SO_2 as firms draw down the existing bank of SO_2 allowances slightly more rapidly under the prerevision NSR rules. The predicted change in national emissions of NO_x is also typically less than 1% (at most 2%) relative to the ERP scenario. Those small changes occur because the Title IV cap on SO_2 emissions and the seasonal cap on NO_x emissions in the East under the NO_x SIP call remain binding. The results come from the RIA, which did not consider the tighter emission caps under CAIR, but the conclusion that national emissions would stay roughly at the caps would also hold for the CAIR case.

In contrast, all three of the R/R/R variants under the prerevision NSR rules typically yield some emission changes when only Title IV and NO_x SIP call caps are in place. EPA's RMRR policy under the prerevision NSR is estimated to affect national emissions of NO_x under "low," "middle," and "high" R/R/R scenarios. SO_2 emissions show some changes for the "middle" scenario, but only for the "high" scenarios are there sufficient retrofits of scrubbers to pull SO_2 emissions below the cap.

Meanwhile, the emission reductions due to imposition of the R/R/R assumption were much smaller if instead the CAIR rule is assumed. Under the CAIR rule, at least 66% of the previously uncontrolled capacity needs to be retrofitted with SCR (the "middle" scenario) for national emissions to drop. For SO_2, the results are the same as under Title IV, with virtually all existing capacity needing to be scrubbed to bring emissions below the cap.

The committee's IPM runs indicate that lower caps for NO_x and SO_2 emission diminish the effects of the prerevision NSR approach on national emissions in later years of the scenario. In particular, for the "high" R/R/R scenarios, under Title IV and the NO_x SIP call, year 2020 national emissions of SO_2 are roughly 50% less compared with a run that assumes the ERP. Under the same scenario but assuming the CAIR rule, national SO_2

emissions in 2020 associated with the prerevision NSR approach are 20% below those under the ERP with reductions split evenly (on a percentage basis) between CAIR-affected and non-CAIR-affected coal-fired generators. However, in 2015, there is a smaller difference in SO_2 emissions between the two rules under either cap (5% lower emissions for prerevision NSR relative to the ERP under CAIR-CAMR and 3% lower emissions for prerevision NSR relative to the ERP under Title IV and the NO_x SIP call). Furthermore, in earlier years, SO_2 emissions are actually projected to be higher under the prerevision NSR approach than the ERP under either cap. That increase occurs because widespread installation of scrubbers lowers the value of SO_2 allowances in the later years and thus weakens the incentive for generators to bank allowances for future use, and this causes emissions to be higher in the near term. As a result, total SO_2 emissions under CAIR for the entire 2007-2020 period are the same with the prerevision NSR rules and the ERP even if all capacity is scrubbed under the prerevision NSR rules (Table 6-8).[33]

For both NO_x and SO_2, unless controls become extensive enough to reduce emissions below the cap, the main effects of an NSR RMRR policy that results in greater retirements, repowering, or retrofits of facilities will be to increase power-production costs and spatially redistribute emissions. National emission totals would not change appreciably. Because of the cap-and-trade programs, reduction of emissions at one facility frees up allowances that allow greater emissions to occur elsewhere. Therefore, the effect of the prerevision NSR policy on SO_2 and NO_x emissions from power plants (in the context of binding national cap-and-trade programs) would be to rearrange emissions across both space and time and to increase costs. The committee was unable to estimate the local emission, air-quality, and health effects of that redistribution, for the reasons described above.[34] Health effects could plausibly increase or decrease, depending on where the emission changes take place.

[33]Note that because emissions are lower in the last year under the R/R/R "high" run, an average over a longer period (such as 2007-2026) would show lower average SO_2 emissions under that run than under the ERP. For reasons explained above, we have not considered IPM results after that year.

[34]One potential indicator of local emission effects of the NSR RMRR policies would be a change in the variance of emission rates across model plants in IPM with these policies. Comparing generation-weighted variances in SO_2 and NO_x emission rates for model plants across the different R/R/R scenarios reveals that in general the variances do not change from baseline levels except in cases where the R/R/R scenarios produce aggregate emissions below those expected under emission caps imposed by other policies such as CAIR-CAMR or the Title IV caps. Contrary to expectations, the variance in emission rates for NO_x is lower in the minimum-cost case (that allows trading) than in the "high" scenario in all years and lower in 2020 for SO_2.

If the effect of the prerevision NSR rules on generator decisions to retrofit, repower, or retire is large enough to pull emissions below the caps, there can be emission benefits. However, the marginal cost of such incremental reductions (in the case in which CAIR-CAMR is assumed) greatly exceeds the average cost of achieving the emission reductions achieved by CAIR relative to a Title IV and NO_x SIP call baseline. That marginal cost is also several times as large as the cost of achieving the same reductions by imposing cap-and-trade policies. That conclusion was the result of an IPM solution obtained by imposing national emission caps equal to the emissions resulting from the most extreme retrofit scenario under the prerevision NSR rules. Thus, we conclude that from the standpoint of limiting national and regional emissions—a goal, but far from the only one, of NSR—a tighter emission cap would likely be a cheaper method of limiting national and regional emissions than NSR. We note, though, that NSR has additional goals, such as preventing local increases in air pollution, and that the IPM model does not permit a comparison between emission caps and NSR as a way to accomplish these goals. We also note that further analyses would be needed to determine whether the marginal costs of tighter caps are justified (Banzhaf et al. 2004). The committee's comparison, which is limited to national emission reduction, should not be taken as an attempt at an overall assessment of NSR.

Alternative assumptions about the cost of generation alternatives to pulverized-coal steam plants—natural-gas costs and investment costs for integrated gasification combined cycle and renewable energy—were also simulated with IPM. Some changes occurred in the mix of new generation plants, but our conclusions about the national emission effects of the ERP are unaffected.

Conclusion Regarding Future Analysis and Data Acquisition

Future analyses of the effects of alternative NSR repair and maintenance rules on the power sector could be made more informative in at least three ways. One is to perform extensive sensitivity analyses to understand how alternative assumptions concerning future economic and technological developments could affect conclusions of an analysis. Time and resource limitations restricted our ability to do that. If uncertainty distributions can be specified for model inputs, it would be possible to use IPM to calculate confidence bounds for model outputs, although, given the current model framework, the number of runs needed to develop appropriate confidence intervals would be substantial in both time and cost.

A second way to improve future analyses might be to solve a stochastic version of IPM in which decisions in earlier years are made subject to uncertainty about future years, and is represented by multiple scenarios each of which has a probability. We understand that such a "two-stage" version of IPM has been tested. A stochastic version of the analysis would provide a more realistic representation of the option value of different control strategies and how generators would adopt physical hedges against risk. However, such a model would be much larger in size than the basic IPM and more expensive to run. Therefore, the committee suggests that research be undertaken on the conditions under which solutions of stochastic simulation models would be both appreciably different from deterministic models (for example, see Murphy and Sen 2002) and also more realistic in terms of characterization of actual market behavior under uncertainty.

The third way we suggest for improving future analyses is to undertake detailed empirical studies of the costs and effectiveness of maintenance and life-extension alternatives for various classes of power generators to increase understanding of the costs and benefits of undergoing NSR from the plant owner's point of view. Such a study would contribute to more realistic characterizations within IPM of the alternatives available to generation owners. It would also yield justification of assumptions concerning whether power generators will choose to avoid or undergo NSR. The results of such studies should be subject to peer review, before assumptions in IPM are changed, to get the benefit of a variety of expertise on this important issue.

7

Emissions, Air Quality, and Human Health

INTRODUCTION

In previous chapters, the committee presented multiple analytic approaches that could be used to evaluate the effects of the New Source Review (NSR) rule changes on pollutant emissions and on efficiency and other end points. A different set of analytic tools would be required to translate the emission changes into changes in air-pollutant concentrations and human health risks. In our interim report (NRC 2005), we briefly summarized the steps needed to estimate environmental and public-health effects, including a general discussion of the important components of atmospheric fate and transport models. In addition, the committee provided an overview of the health effects of the air pollutants potentially influenced by NSR, the attainment-nonattainment status of different geographic areas, and trends in emissions across time and economic sectors.

Given the findings from earlier chapters, the committee has two primary goals in this section. One is to update and expand on the information presented in the interim report, with more emphasis on how emissions subject to NSR might vary by state and region and how the effects associated with differences in the NSR rules might be related to the overall emissions of different criteria pollutants in these states; the purpose of this comparison is to provide insight into the economic sectors and geographic areas where the NSR rule changes could theoretically have an important influence on overall emissions. The second is to consider factors that might influence the relationship between emission and ambient concentrations and the relationship between ambient concentrations and health outcomes including a more general discussion of atmospheric processes and an evaluation of source-receptor analyses incorporated into past regulatory-effect analyses; this will improve understanding of the geographic locations in which changes in emissions might be important from a public-health perspective. Descriptions of the collection and processing of data are incorporated by reference to our interim report.

REVIEW OF PAST FINDINGS

In our interim report, we examined the criteria pollutants—carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), lead (Pb), ozone (O_3), particulate matter (PM_{10} and $PM_{2.5}$) that are regulated under the National Ambient Air Quality Standards (NAAQS) (Table 2-1) and to which NSR applies. It was found that NO_2 and SO_2 NAAQS have not been exceeded in any monitored part of the United States for more than 10 years, although some of these areas have not yet been designated as officially in attainment. CO exceedances were found at a few neighborhood-scale locations (Chow et al. 2002) near roadways and were clearly attributable to mobile-source emissions not subject to NSR. Pb nonattainment areas in Missouri and Montana are near lead-production facilities that are currently subject to emission-reduction efforts. High CO concentrations were usually exacerbated by local topographic and meteorologic characteristics. PM_{10} nonattainment areas were found mostly in the western states, in many cases owing to wintertime residential woodburning, fugitive dust, or nearby industrial sources (usually fugitive dust from material handling or uncontrolled ducted emissions). Exceptions were California's South Coast Air Basin (Los Angeles area) and central valley, where fall and wintertime PM_{10} exceedances were driven by high $PM_{2.5}$ nitrate and carbon components. Many of the PM_{10} nonattainment areas have implemented appropriate control measures, and PM_{10} levels have been reduced (EPA 2004h).

$PM_{2.5}$ and O_3 are the criteria pollutants with the most geographic areas in nonattainment. In addition, in summarizing the health effects of criteria air pollutants, we found the most substantial evidence of health effects in connection with current atmospheric concentrations of $PM_{2.5}$ and O_3. Thus, from a public-health perspective, $PM_{2.5}$ and O_3 have the most important effects attributed to changes in NSR.

Ambient O_3 and much of the $PM_{2.5}$ are not directly emitted but form through atmospheric reactions of directly emitted volatile organic compounds (VOCs), NO_x (sum of nitric oxide [NO] and NO_2, expressed as NO_2 in emission inventories), and SO_2 (Pandis 2004). Sulfates, nitrates, and some of the organic carbon found in $PM_{2.5}$ are termed secondary aerosol, owing to their formation from emitted gases, as opposed to directly emitted PM, which is termed primary aerosol. NSR changes that affect VOC, NO_x, SO_2, and primary PM emissions will affect O_3 and $PM_{2.5}$ NAAQS attainment.

Maps in the interim report showed that areas where the O_3 NAAQS is exceeded include multiple counties in central and Southern California; Las Vegas, Nevada; Phoenix, Arizona; along the Colorado Front Range; the Houston, Dallas, and San Antonio areas in Texas; nearly the entire Midwest and Southeast; and the Washington-Boston corridor. It was noted that O_3 concentrations can seldom, if ever, be reduced meaningfully by controlling single sources of precursors; reduction strategies need to encompass many sources of NO_x and VOCs. Those groups of sources may be hundreds of kilometers from the locations where exceedances are measured and outside the jurisdictions of local air-quality authorities (Seinfeld 1988; Sillman 1993, 1999; NARSTO 2000; Placet et al. 2000; Russell and Dennis 2000; Solomon et al. 2000; Watson et al. 2001). The rate of O_3 formation can be limited by the amounts of NO_x or VOCs emitted, but the critical precursor to target to reduce O_3 formation varies with time and location (e.g., Nobel et al. 2001; Fujita et al. 2003; Reynolds et al. 2003, 2004).

Our interim report showed that nonattainment areas for the annual average $PM_{2.5}$ NAAQS are more numerous and are primarily in California and the eastern United States. In addition, many areas of the eastern United States have $PM_{2.5}$ concentrations that approach the annual NAAQS of 15 μg/m3 and may exceed possible limits proposed for a revised 24-hour $PM_{2.5}$ NAAQS (70 Fed. Reg. 944 [2005]). Where chemical measurements of $PM_{2.5}$ sulfate (SO_4), nitrate (NO_3), organic material, elemental carbon, and crustal material were available during 2002, many of the urban sites experienced larger amounts of carbonaceous (organic material plus elemental carbon) $PM_{2.5}$ than the nonurban sites, probably because primary emissions from traffic and fuel use were more abundant. An exception was a large nonurban (and urban) carbon fraction in the Pacific Northwest due to extensive wildfires during the summer of 2002. Sulfate concentrations were much higher in the eastern United States than in the West and were similar at nearby urban and regional sites; this is consistent with a regional distribution. Nitrate constituted a larger fraction of $PM_{2.5}$ in the West, especially in California. Our interim report showed that more than half the U.S. population lives in counties that exceed the O_3, $PM_{2.5}$, or PM_{10} NAAQS (EPA 2004i).

EMISSIONS

Our interim report explained how EPA prepares its national database of air emissions based on input from state and local air agencies, Indian tribes, and industry as the National Emissions Inventory (NEI) (EPA 2004j). The NEI categorizes emitters into the following:

• Point sources that are large stationary emitters, such as electricity generators, refineries, and other industries, that can be identified by name and location. A major source emits a threshold amount (or more) of at least one criteria pollutant and must be inventoried and reported. Most of the sources with any criteria pollutant emission greater than 100 tons/year are subject to NSR when they are newly constructed or undergo modification.

• Area sources that are small stationary emitters, such as residential heating, small generators, and small industries. This category also includes large but diffuse emitters such as wildfires and dust from agricultural tilling. These sources do not individually produce sufficient emissions to qualify as major sources. Most area sources are not subject to NSR.

• Mobile sources that are not located at fixed points, such as on-road cars and trucks, as well as nonroad locomotives, ships, aircraft, construction equipment, farm equipment, and mobile generators. These are usually powered by gasoline and diesel engines and are regulated by different sectors by emission limits, fuel specifications, and inspection and maintenance programs. Mobile sources are not subject to NSR.

Whereas Chapter 3 examined permitting activity within various point-source categories, this chapter considers emissions from point sources that are possibly subject to NSR in a context of emissions from all emission sources. To expand on the information presented in our interim report, the committee examined data on the fraction of total emissions potentially subject to NSR within each state. This information can help determine geographic locations and pollutants for which NSR-eligible sources might contribute significantly to total emissions and potential exceedances of NAAQS in downwind states. Emissions are stratified by sector and state to provide further context about the sectors and locations that may contribute most substantially to ambient air pollution and related health effects. Data from our interim report about national regional emissions patterns and temporal trends in emissions are also included.

Our interim report noted the following limitations of the NEI, both in general and for the purpose of evaluating the effects of NSR changes on emissions:

• NEI data are complete and validated for 1999. Emissions have probably changed in the last 6 years. Emission data for determining the effects of the NSR rule changes would therefore not be available for a number of years.

• Data on point-source emissions are more accurate than data on mobile-source and area-source emissions because many of the former are derived from continuous emission monitors (CEMs) and nearly all reflect actual operating volumes and pollution-control efficiencies. Data for area and mobile sources rely on surrogates of operating activities (such as statewide fuel consumption and vehicle-miles traveled) and generic emission factors that are derived from a small number of individual emitters, as opposed to the total.

- The NEI does not contain information on which point sources are subject to NSR, which ones have obtained NSR permits, or the emission potential of sources subject to NSR. The year in which each point source began operating is not included with the emission information although such information on electricity-generating facilities is available elsewhere.
- The NEI is updated every 3 years, and interpolations and corrections are made for trend analysis. It does not contain sufficient detail to examine how selection of different years for baseline averaging would affect the baseline. Although nationwide 2002 NEI emissions were available after our interim report, these had not been completely validated and it was not possible to obtain the industrial sector and spatial resolution needed for the analysis presented here.
- Although there is a provision for specification of pollution-control equipment, the NEI contains little detail on where and when emission-reduction measures were implemented for individual sources.

Fraction of Total Emissions Potentially Subject to New Source Review

The fraction of emissions potentially subject to NSR was estimated from the NEI for each state by summing 1999 point source SO_2, NO_x, $PM_{2.5}$, and VOC emissions from individual emitters with greater than and less than 100 tons/year. Emissions exceeding 100 tons/year were assumed to be subject to NSR, although several of the included sources may be subject to a ≥250 tons/year limit. This may underestimate emissions subject to NSR in that some sources receive permits for more than their actual emissions. This is offset by including some emissions from source categories subject to the ≥250 tons/year limit. Uncertainties due to those limitations are believed to be lower than other uncertainties in the total emission rates. Figure 7-1 shows how the fraction of NSR-eligible sources varies by state and for the entire United States.

The VOC fraction from point sources is small compared with total VOC emissions. Mobile and area sources dominate VOC emissions in all states. Only Alabama (6%), Arkansas (7%), Hawaii (9%), Kentucky (6%), Louisiana (12%), Tennessee (10%), Texas (6%), and Wyoming (9%) have fractions of NSR-eligible point-source emissions that exceed 5% of the total. NSR rule changes are unlikely to have a large effect (a fraction of <5%) on total VOC emissions in most states, although this does not necessarily imply that incremental benefits or adverse effects would not be obtained.

For primary $PM_{2.5}$, 12% of total U.S. emissions could be from NSR-

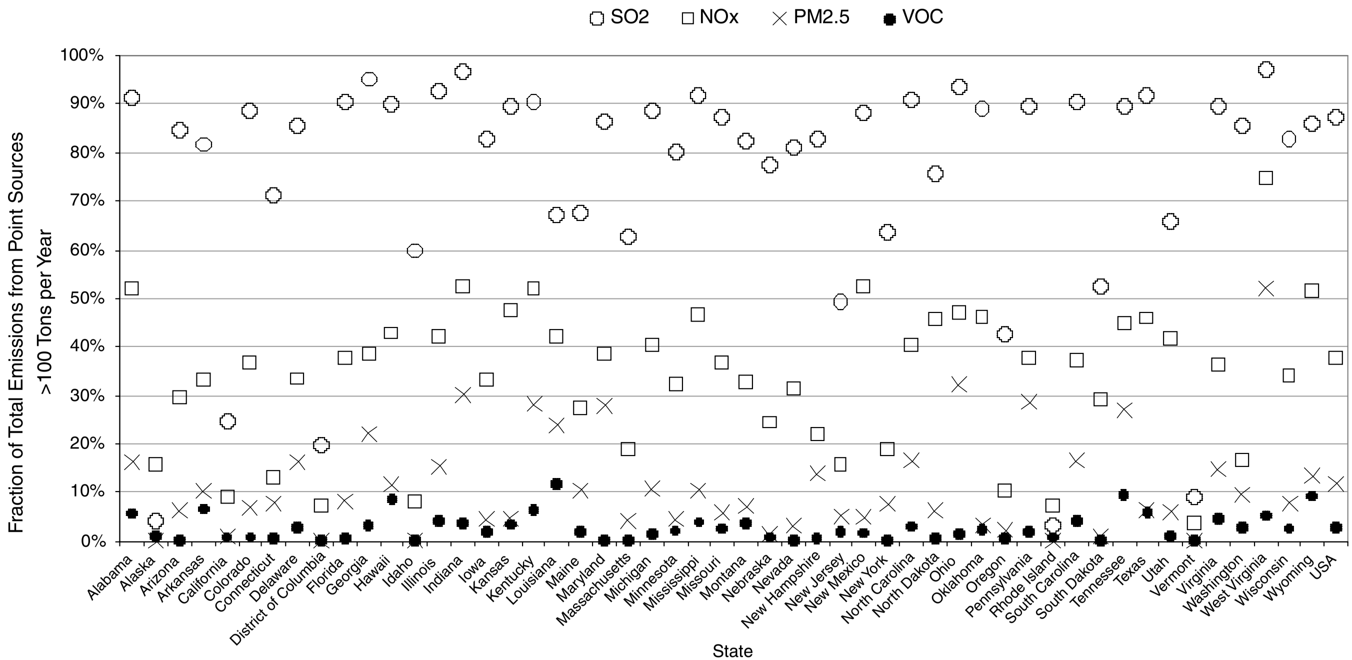


FIGURE 7-1 Fraction of total 1999 emissions by state from emitters that are potentially subject to NSR. Assumes that all point-source emissions over 100 tons/year are subject to NSR. Nationwide fractions (USA) are also shown.

eligible sources. Only in Alaska, California, the District of Columbia, Idaho, Iowa, Kansas, Massachusetts, Minnesota, Nebraska, Nevada, Oklahoma, Oregon, Rhode Island, South Dakota, and Vermont is less than 5% of total emissions derived from point sources that have $PM_{2.5}$ emissions over 100 tons/year. More than 27% of the total for Indiana, Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, and West Virginia comes from potential NSR sources; the maximum is 52% in West Virginia. NSR rule changes that result in increased or decreased emissions would potentially have their greatest effect on emissions in those states and on air quality and health effects in those states and at downwind locations.

For NO_x, 38% of the U.S. total derives from potential NSR emitters. Only California (9%), the District of Columbia (7%), Idaho (7%), Rhode Island (7%), and Vermont (4%) show fractions of less than 10% of the total. More than 50% of total NO_x emissions in Alabama, Indiana, Kentucky, New Mexico, West Virginia, and Wyoming comes from NSR-eligible sources, with fully 75% of the total derived from these emitters in West Virginia. Even small changes in NO_x emissions owing to NSR rule changes might have nonnegligible effects on emissions in these states.

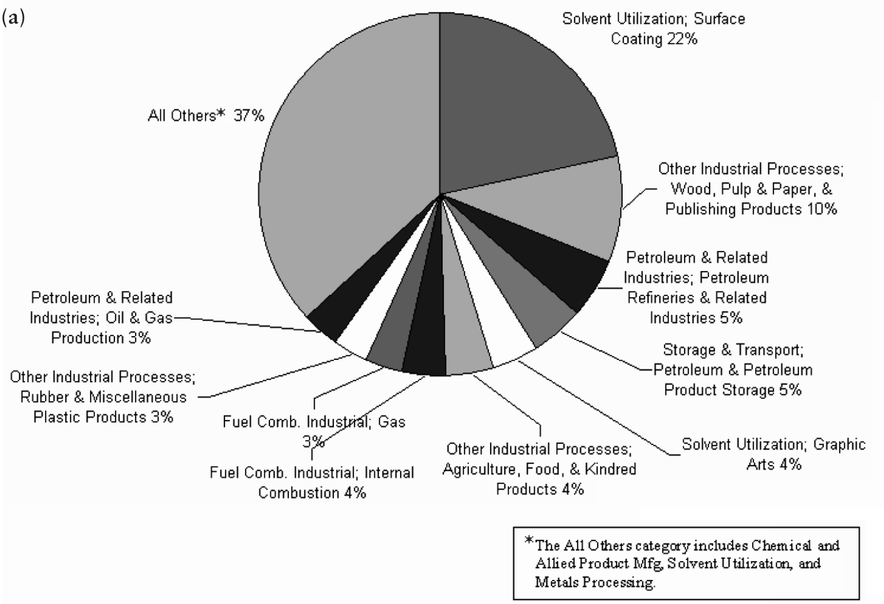
SO_2 emitters are dominated by point sources with rates exceeding 100 tons/year in nearly all the states. Some 87% of total U.S. emissions is from the NSR-eligible emitters. Only Alaska (4%), California (25%), the District of Columbia (20%), New Jersey (49%), Oregon (43%), Rhode Island (3%), and Vermont (9%) derive less than half the total SO_2 emissions from these sources. NSR changes that increase or decrease emissions have the potential to affect total SO_2 emissions most significantly in most states, compared with percentage changes in other criteria air-pollutant emissions (see Chapter 6).

Nationwide Emission-Source Categories

Figure 7-2 summarizes contributions of different emission categories to total point-source emissions for the entire United States. For $PM_{2.5}$, about 50% of total point-source emissions are due to fuel combustion in the electricity-generating industry with about 40% due to coal combustion. Other important source categories are wood, pulp and paper, metals, and mineral processing. Point sources account for about 18% of $PM_{2.5}$ emissions and about 7% of PM_{10} emissions (EPA 2003d). Primary $PM_{2.5}$ and PM_{10} emissions contribute a minor fraction (under 10%) of measurable ambient PM (Chow and Watson 2002; EPA 2004k).

Figure 7-1 shows that large point sources are important contributors to pollutants (SO_2, NO_x, and, to a smaller extent, VOCs) that participate in the formation of secondary PM. For SO_2, about 75% of point-source emissions is attributable to coal combustion by the electricity-generating

(a)



(b)

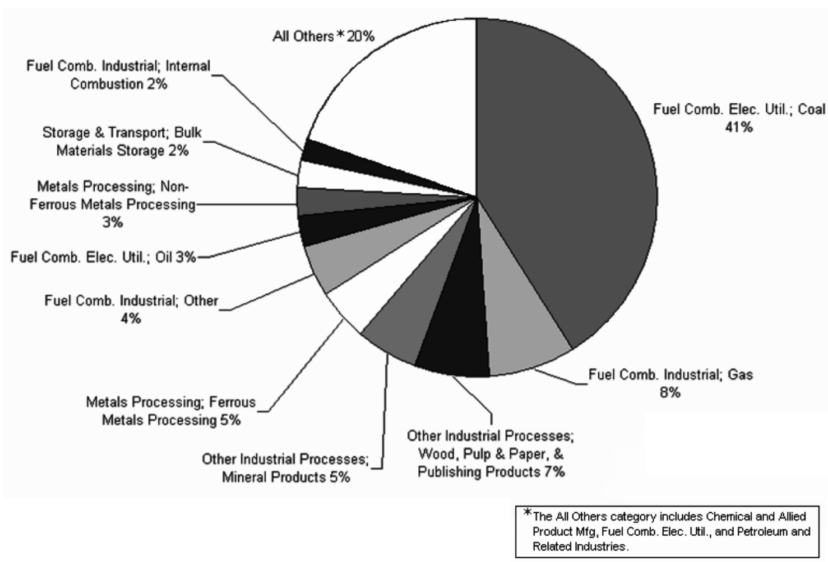


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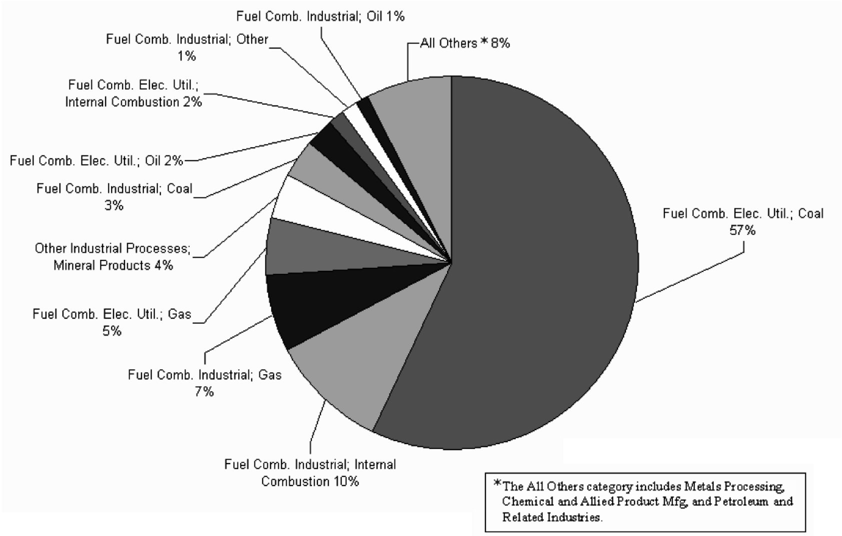
FIGURE 7-2 Nationwide 1999 top 10 point-source emission categories for (a) VOC, (b) $PM_{2.5}$, (c) NO_x, and (d) SO_2. SOURCE: EPA 2003d.

(c)



(d)

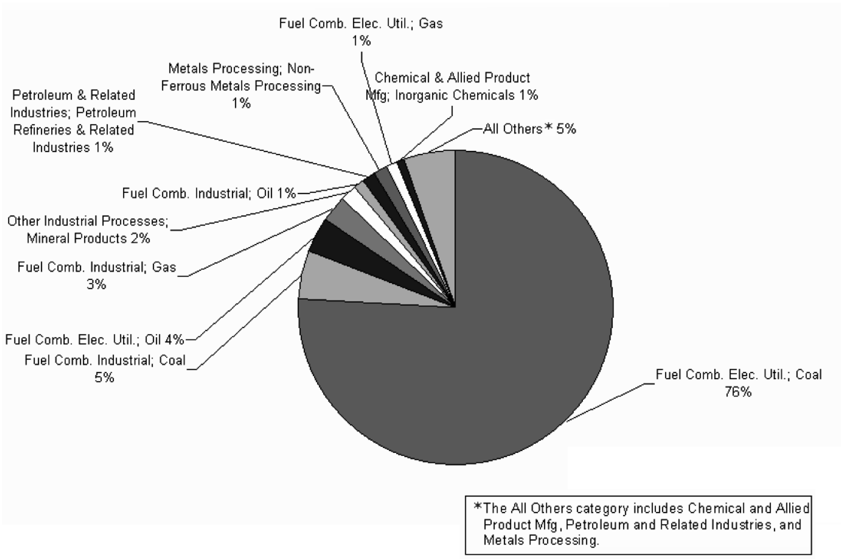


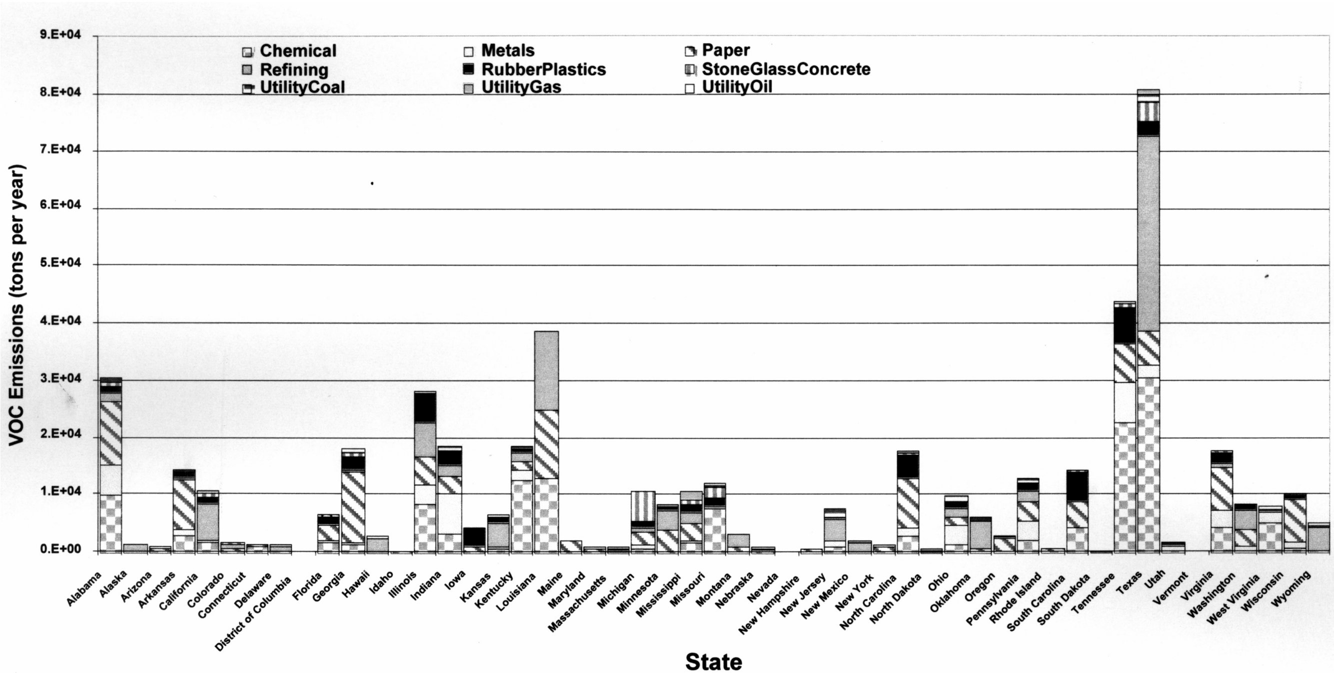
FIGURE 7-2 Continued

industry, with the remaining contributions due to fuel combustion at other industrial sources (Figure 7-2). In contrast, only about 50% of NO_x point-source emissions is due to coal combustion in electricity-generating facilities, with the remainder divided equally among other fuel-combustion activities. In contrast with the predominance of fuel-combustion activities for NO_x and SO_2, point sources of VOCs are attributable primarily to petroleum and related industries, chemical manufacturing, and other industrial processes, including pulp and paper, food, rubber, and plastics manufacturing. VOC-derived organic aerosol may constitute an important fraction of $PM_{2.5}$ in U.S. regions when photochemical transformation predominates (Cabada et al. 2004; Dechapanya et al. 2004). Individual VOCs can differ substantially in the rates at which they react in the atmosphere and the effects that they have on the formation of O_3 and PM (Carter 1994; Atkinson 2000; Pandis 2004), but these differences are not considered by NSR. Another important contributor to secondary aerosol formation is ammonia emissions. Nationally, point sources contribute only a minor fraction of ammonia emissions compared with agricultural sources (EPA 2004k).

Sources with Emissions Greater than 100 Tons/Year by State

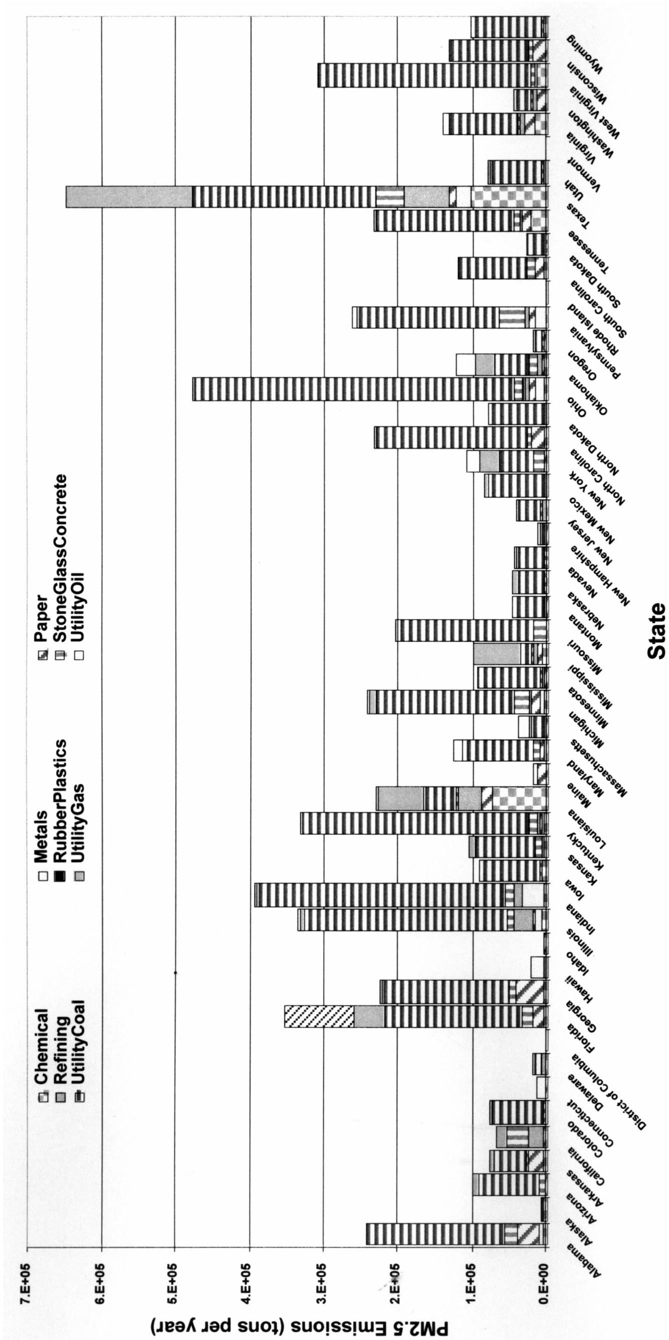
The information presented above helps to contextualize NSR-eligible sources relative to other emission sources, but it is also important to consider emissions from individual states because these are the basis of statewide and regional emission rules. Figure 7-3 summarizes emissions by state for point sources most likely to be subject to NSR (those emitting more than 100 tons/year). It complements the emission maps in our interim report that show total point-source and electricity-generating facility emissions by state, and it expands on Figures 7-1 and 7-2. $PM_{2.5}$, NO_x, and SO_2 emissions are dominated by electricity-generating-facility emissions in most states, especially states with the highest emissions.

Coal-fired power generation is the dominant emitter in each state where emissions are high. Only Florida has a large quantity of emissions from oil-fired electricity generators. Gas-fired generators are important sources of NO_x in Florida, Louisiana, Mississippi, New York, Oklahoma, and Texas. Sources other than electricity-generating facilities are important as a fraction of the total in the states with the lowest emissions. Emissions from the chemical and refining industries are substantial contributors to total emissions in Louisiana and Texas. The paper industry is a substantial contributor in Alabama, Georgia, and Michigan. The highest $PM_{2.5}$, NO_x, and SO_2 emissions are from the midwestern states and Texas, again dominated by coal-fired power generation. Electricity-generating facility emissions in those states contribute most to NSR-eligible emissions, and this indicates that the most important emission changes could potentially be obtained in



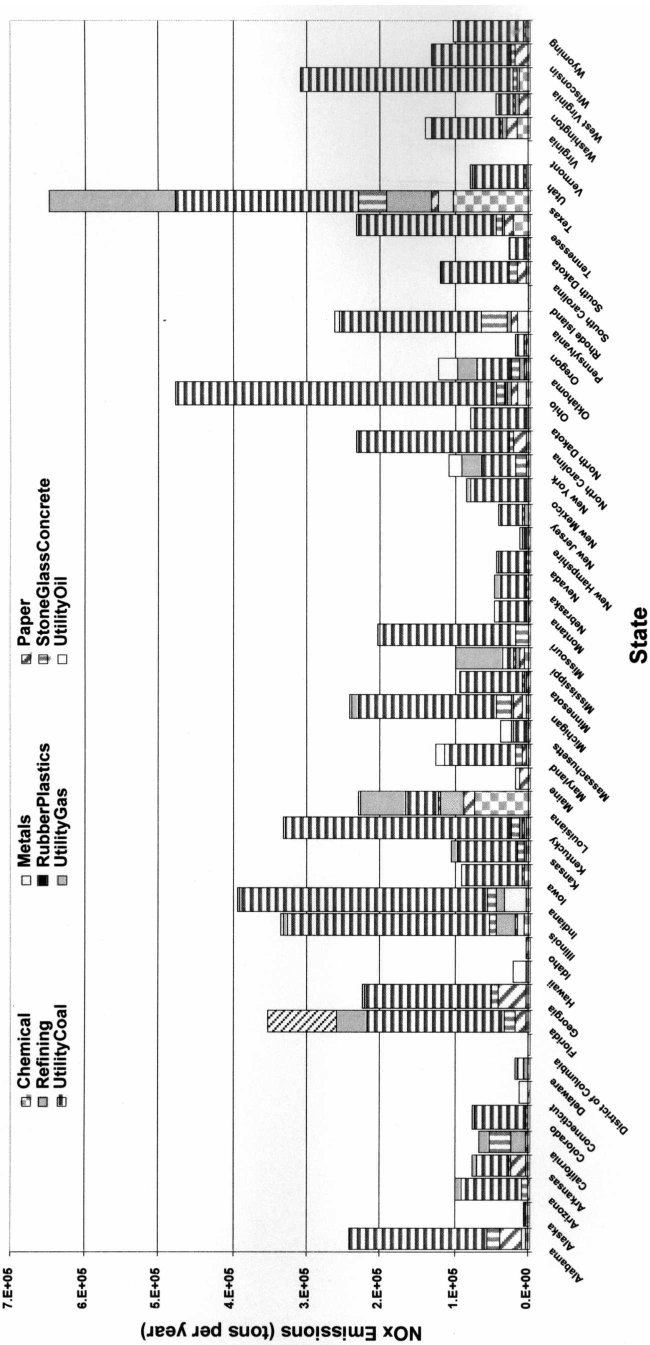
(a)

FIGURE 7-3 1999 emissions exceeding 100 tons/year by source category in each state for (a) VOCs, (b) $PM_{2.5}$, (c) NO_x, and (d) SO_2.



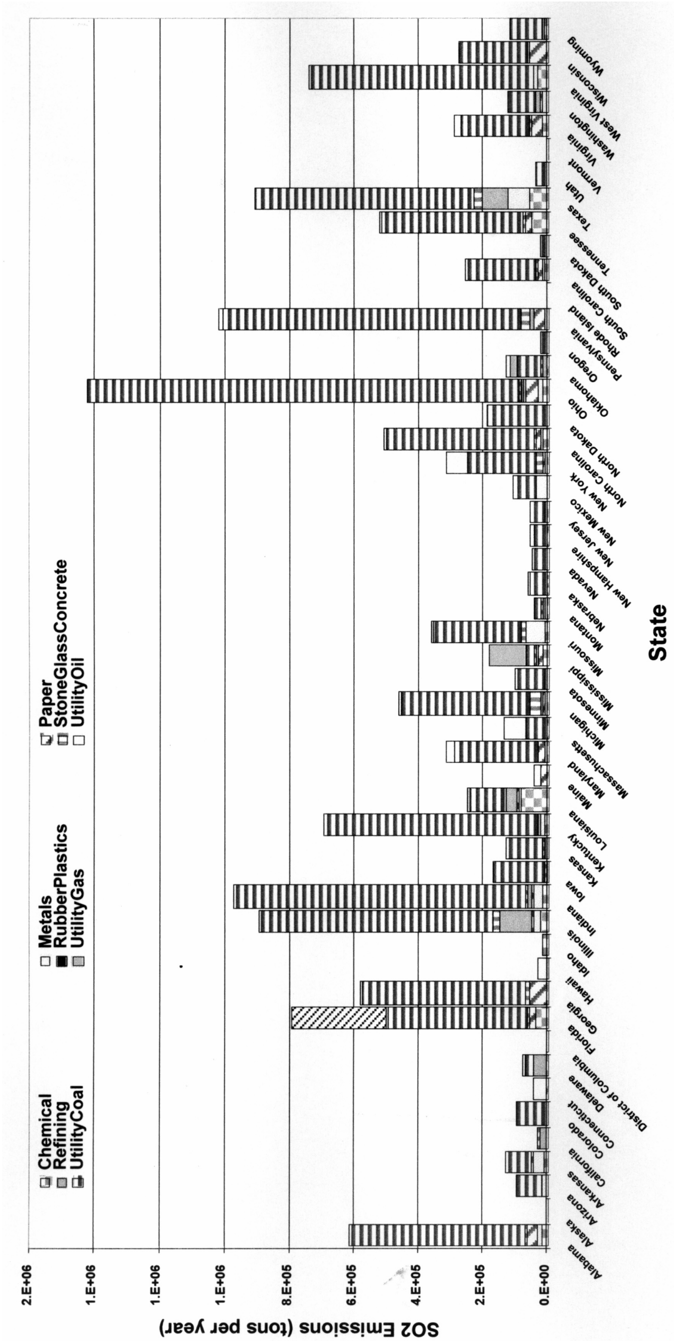
(b)

FIGURE 7-3 Continued



(c)

FIGURE 7-3 Continued



(d)

FIGURE 7-3 Continued

those settings. However, it is not necessarily the case that the highest emitters experience the largest changes in emissions due to NSR rule changes, inasmuch as different sectors are influenced by NSR in different ways. Nor is it necessarily the case that sources in states with lower emissions have no detectable contributions to adverse air quality and health effects. Given those qualifications, these data provide the ability to focus future modeling efforts first on sources and regions that contribute most to the emission inventory.

VOC emissions follow a different pattern, which is dominated by sources other than electricity-generating facilities. Chemical and refining industries dominate the VOC emissions, and some states—such as Alabama, Georgia, and Louisiana—have important contributions from the paper industry. Texas and the southern states have the highest VOC emissions.

Emissions by Age of Facility

Knowing the ages of facilities would provide insight about which have been subject to New Source Performance Standards (NSPS). Although information on facility age is not available for all sectors, relevant data inferred from boiler sales are available for the electric utility sector and for commercial and industrial boilers (EEA, 2005). The data suggest that over 47% of total large boiler capacity is at least 40 years old; large boilers are defined as those with a total capacity in excess of 10 million Btu/hour. Roughly 7% of total boiler capacity is less than 10 years old. Table 7-1 a and b summarize rates of NO_x and SO_2 emission from coal-fired generators in 2002 by the period during which a power plant came into service. They also provide information on how much generators in each period contributed to total generation and total capacity of coal-fired generation. Table 7-1b includes information on average capacity factor (actual generation divided by potential generation) of generators by vintage and the average heat rate (in British thermal units of heat input from fuel combustion per kilowatt-hour of electricity generated) for generators in each vintage class.

The data show that older facilities have higher emission rates than newer facilities, and older facilities contribute more to total emissions than they do to total electricity generation from coal units. With perhaps one exception, heat rates are lower for newer power generators than for older units. Older generators have lower capacity factors than newer generators and, if those generators were operated more often, their average heat rates likely would be lower. There is a selection bias in the data whereby the generators with lower heat rates of any vintage typically are the ones that receive greater use.

Table 7-1 c and d display the same data organized in a different way. Coal-fired generating units are classified by an NSPS category according

TABLE 7-1 Emissions from Coal-Fired Electricity Generation by Age

(**a**) 2002 NO_x Emissions and Share of Generation of Coal-Fired Capacity by Vintage

Power Plant Established	Avg. NO_x Emission Rate (lb/MWh)	% Total NO_x Emitted	% of Coal-Fired Electricity Generation	% of NO_x Emitted per % of Electricity Generated[a]	% of Coal-Fired Electricity Capacity
Pre-1950	5.51	0.65	0.50	1.31	0.92
1950-1959	5.07	15.11	12.56	1.20	14.32
1960-1969	4.56	21.27	19.65	1.08	20.51
1970-1979	4.28	39.31	38.76	1.01	38.13
1980-1989	3.53	21.74	25.97	0.84	23.84
Post-1990	3.15	1.92	2.56	0.75	2.27

(**b**) 2002 SO_2 Emissions and Performance of Coal-Fired Capacity by Vintage

Power Plant Established	Avg. SO_2 Emission Rate (lb/MWh)	% of Total SO_2 Emitted	% of Coal-Fired Electricity Generation	% of SO_2 Emitted per % of Electricity Generated[a]	Average Capacity Factor (%)[b]	Average Heat Rate (Btu/kWh generated)
Pre-1950	20.58	1.02	0.50	2.04	36.35	12,549
1950-1959	15.78	19.64	12.56	1.56	58.93	10,668
1960-1969	13.92	27.12	19.65	1.38	64.37	10,150
1970-1979	9.31	35.75	38.76	0.92	68.29	10,270
1980-1989	6.02	15.49	25.97	0.60	73.17	10,401
Post-1990	3.88	0.98	2.56	0.38	75.80	9,982

(**c**) 2002 NO_x Emissions and Share of Generation of Coal-Fired Capacity by NSPS[c]

NSPS Status According to EIA 767	Avg. NO_x Emission Rate (lb/MWh)	% Total NO_x Emitted	% of Coal-Fired Electricity Generation	% of NO_x Emitted per % of Electricity Generated[a]	% of Coal-Fired Electricity Capacity
Unknown	2.93	0.16	0.23	0.69	0.27
Not affected by NSPS	4.67	65.90	59.51	1.11	62.62
Subject to Aug. 1971 standards (D)	3.57	26.73	31.58	0.85	29.56
Subject to Sept. 1978 standards (Da)	3.50	7.21	8.68	0.83	7.56

TABLE 7-1 Continued

(d) 2002 SO_2 Emissions and Performance of Coal-Fired Capacity by NSPS[c]

NSPS Status According to EIA 767	Average SO_2 Emission Rate (lb/MWh)	% of Total SO_2 Emitted	% of Coal-Fired Electricity Generation	% of SO_2 Emitted per % of Electricity Generated[a]	Average Capacity Factor[b] (%)	Average Heat Rate (Btu/kWh generated)
Unknown	4.56	0.10	0.23	0.45	56.58	11,247
Not covered by NSPS	12.93	76.25	59.51	1.28	63.85	10,250
Subject to Aug. 1971 standards (D)	6.66	20.86	31.58	0.66	71.79	10,519
Subject to Sept. 1978 standards (Da)	3.23	2.78	8.68	0.32	77.17	10,185

[a]If the generators of a particular vintage (or in a particular NSPS category) emitted a particular pollutant in proportion to its share of total electricity generation, the value would be 1.

[b]Capacity factor of units that operated that are strictly associated with boilers in CEM system database.

[c]The Subpart D standards apply to fossil-fuel-fired steam boilers for which construction began after August 17, 1971. The Subpart Da standards affect those boilers that began construction after September 18, 1978. For boilers not covered by NSPSs construction began before August 17, 1971. A new NSPS for NO_x was promulgated in 1998, but no new coal-fired generating facilities have been permitted since this new standard was issued.

NOTES: All quantities, including percentages of emissions and generation capacity, are calculated with reference only to coal-fired generating units. Percentages (taking account of rounding) add to 100% because other types of generating capacity are not considered. These tables and the associated dataset were constructed by David Evans of Resources for the Future. Data used to make these tables come from three sources: emission data are from EPA's CEM system database; generation and capacity data are from EIA's 767 dataset; and information on vintage of generating units is from EIA's Form 860 dataset.

SOURCE: EIA 2004b,c; EPA 2004m.

to information from U.S. Energy Information Administration (EIA) Form 767 for 2002 (EIA 2004b). Most of the capacity and generation are not subject to NSPS. Generators not subject to NSPS typically have higher SO_2 and NO_x emission rates (in pounds of pollutant per megawatt-hour of electricity generated) than generators that were permitted under the NSPS that came into effect in 1971. The generators in the post-1978-standard category have substantially lower SO_2 emission rates than those subject to earlier standards, but NO_x emission rates are nearly identical with those of the earlier group. That reflects the fact that NSPS for NO_x did not change much in 1978 (Burtraw and Evans 2004). The NSPS regime depends on when construction started, whereas the vintages in Tables 7-1a and b are determined by when a generator came into service.

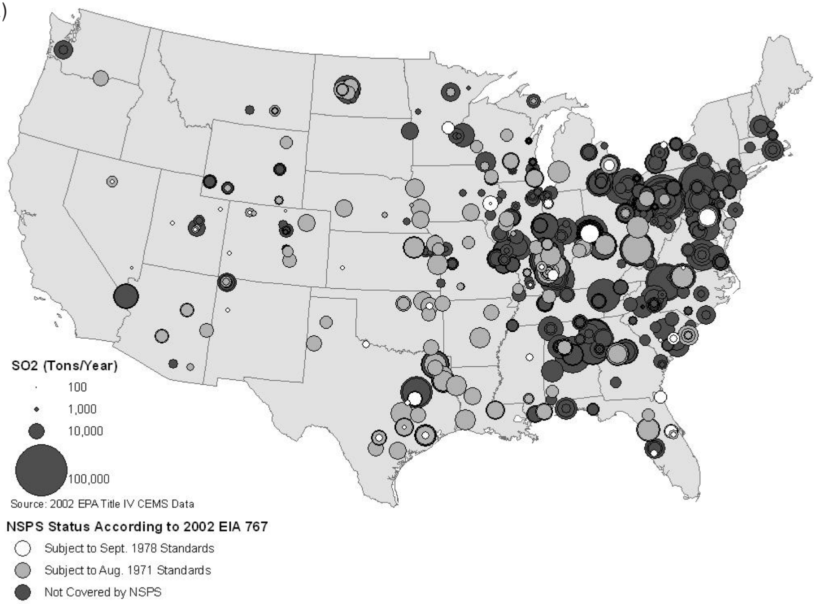
Figure 7-4 shows annual emissions of SO_2 and NO_x in 2002 from generating facilities categorized by NSPS status according to EIA from 767 data. The coal-fired generating units not covered by NSPS are predominantly in the eastern United States, with large concentrations in Pennsylvania and Ohio, upwind of major East Coast population centers, and with other clusters in Kentucky, southern Illinois and Indiana, the Carolinas, and Alabama. Those units tend to have higher SO_2 annual emission rates than plants permitted under the 1971 and 1978s. The smaller variation in total annual NO_x emissions across the different NSPS categories is consistent with the smaller differences in average NO_x emission rates across the different classes of generating units. Most of the emitting units are in the East, but new units can have total annual emissions as high as older units, reflecting in part the higher capacity factors at the newer units. Geographic concentrations of NO_x emissions typically are in the same locations as concentrations of SO_2 emissions.

Emission Trends

EPA has been reporting emissions by source categories since the early 1970s (EPA 2004j). Regulations controlling emission sources of pollution have been implemented over the last several decades and have been associated with declining emissions of some pollutants in some categories. Because NSR is directed at major stationary sources, the focus here is on these sources.

Figure 7-5 shows the trend of point-source emissions of NO_x, VOCs, PM_{10}, and SO_2 since 1970. Point-source NO_x emissions have remained nearly constant over the last 30 years, with power-generating point sources dominating them. Total point-source SO_2 emissions have decreased over the last 30 years. Much of the early decreases in point-source SO_2 emissions resulted from decreases in the metal-smelting sector; later decreases are due to reductions from the electricity-generating sector. Nevertheless, point sources remain a large fraction of SO_2 emissions, and point-source emissions are responsible for a large fraction of PM. PM_{10} emissions declined substantially from 1970 to 1985 because of industrial emission controls; there have been no major changes since 1985. $PM_{2.5}$ has remained largely unchanged (not shown in the figure) since it was first reported in 1995. VOC emissions declined over the last 30 years, for a variety of reasons (e.g., emission controls for O_3 abatement).

(a)



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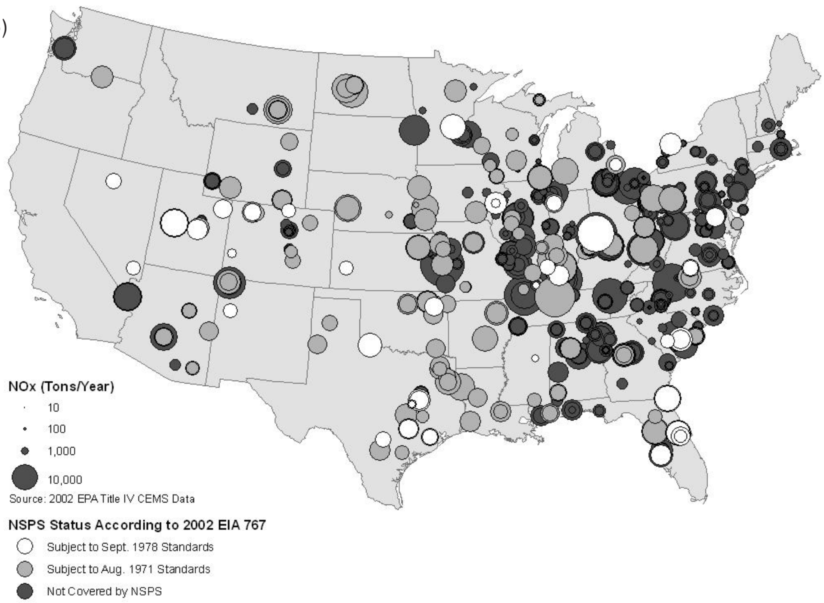


FIGURE 7-4 2002 emissions from utility-scale coal-fired generators that operated in 2002 for (a) SO_2 and (b) NO_x. SOURCE: EIA 2004b; EPA 2004m. Map drawn by Sean M. Raffuse, Sonoma Technology, Inc.

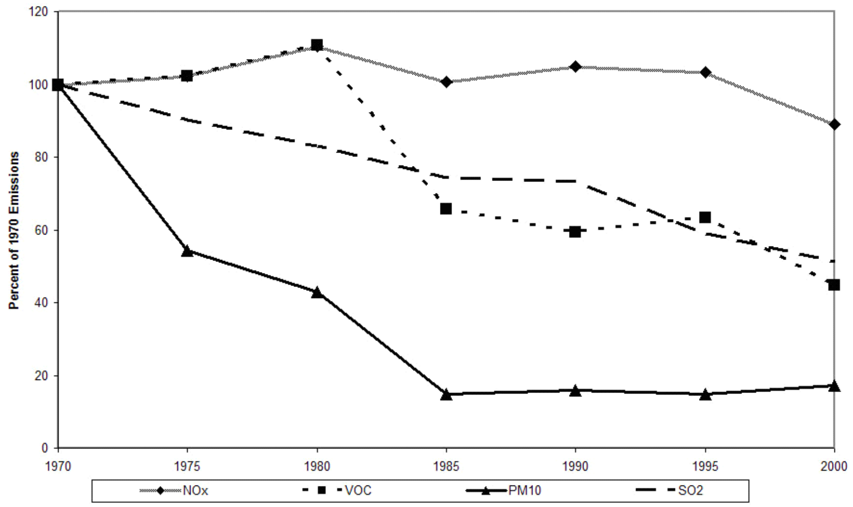


FIGURE 7-5 Criteria-pollutant emission trends for point sources. SOURCE: Data from EPA 2004i.

ESTIMATING EFFECTS OF EMISSIONS ON AMBIENT CONCENTRATIONS

Conceptual Model

As noted in the introduction to this chapter, directly emitted gaseous VOCs, NO_x, and SO_2 are precursors of gaseous O_3 and for $PM_{2.5}$, including major constituents such as SO_4, NO_3, and secondary organic aerosol (SOA). Figure 7-6 illustrates some of the pathways that convert precursor emissions into $PM_{2.5}$ and O_3.

O_3 is formed from the photochemical oxidation of VOCs (labeled RO_2 in Figure 7-6) in the presence of NO_x. The reaction is self-perpetuating because NO is regenerated from the photolysis of NO_2. That explains why O_3 is affected by both NO_x and VOC emissions. The complexity of those interacting cycles of pollutants means that incremental emission decreases in one pollutant may not result in proportional decreases in O_3. Variability in emission-source operations and meteorologic conditions creates uncertainty in the O_3 concentrations to which downwind populations may be exposed. The nonlinearity of this system may actually result in an increase in O_3 with small reductions in VOC or NO_x precursor emissions.

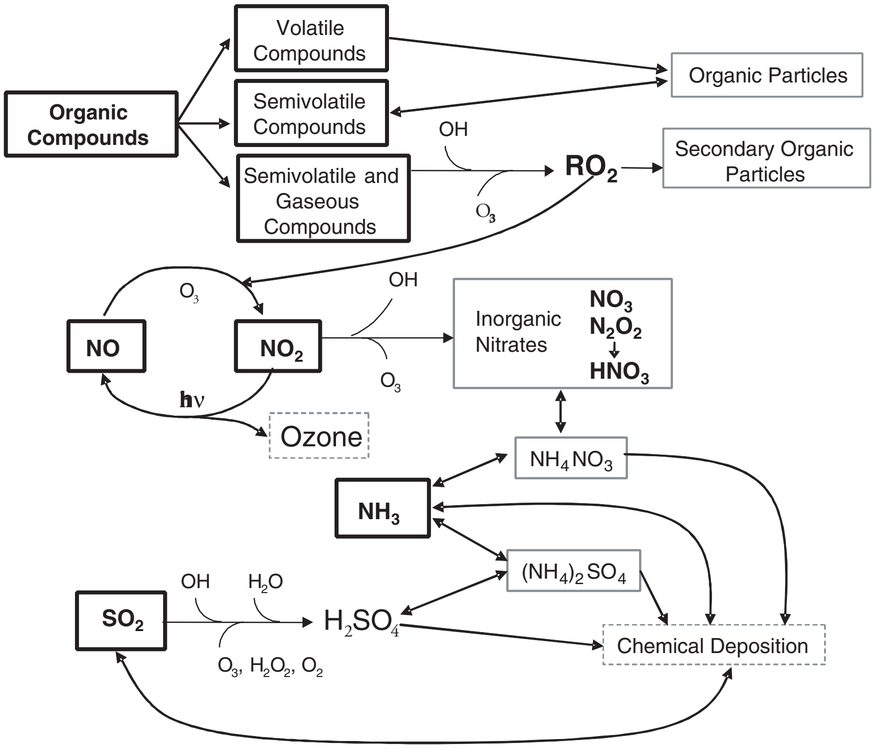


FIGURE 7-6 Chemical links between O_3 and PM formation. Major precursors are shown in boxes with thick sides. Secondary particle components are shown in boxes with thin-sided solid sides. SOURCE: NARSTO 2004. Reprinted with permission; copyright 2004, Cambridge University Press.

Secondary PM is produced by reactions that involve SO_2, NO_x, VOCs, and ammonia (NH_3). Oxidizing agents—produced by VOCs and NO_x—convert SO_2 to sulfuric acid and then to SO_4; they also convert NO_x to nitric acid and then to NO_3. Those stable products form into particles and typically are neutralized by NH_3 to form salts (ammonium sulfate and ammonium nitrate). The same reactions in which RO_2 compounds are produced and O_3 is formed make organic components that condense into particles. Aqueous-phase reactions in fog and cloud droplets also produce organic and inorganic products that contribute to mass in the condensed phase.

Estimating Effects of Emission Changes with Air-Quality Models

As described in our interim report, atmospheric fate and transport models are used to relate emission changes to temporally and spatially indexed ambient concentrations and deposition. The effects of changes in the NSR rules on ambient concentrations depend on how the effects of emission changes on ambient concentrations are estimated by the models. This section focuses on the air-quality modeling of O_3 and PM because there are many areas that do not attain the NAAQS for these pollutants. This focus does not imply that SO_2, NO_x, and CO emission changes may not be influential in some local settings, but rather that national-level health estimates will depend largely on ambient PM and O_3 concentration changes.

In earlier assessments, such models as the Urban Airshed Model (UAM) were used to evaluate O_3 concentration changes. Although those models capture many essential factors that influence O_3 formation, UAM has been shown to underestimate diurnal variability and has been recommended more for average patterns over longer periods than for site-specific short-term estimates (Hogrefe et al. 2001a,b; Hogrefe and Rao 2001). Models like the Regulatory Modeling System for Aerosols and Acid Deposition (REMSAD, SAI 1998) were used to determine secondary SO_4 and NO_3 formation, which capture basic phenomena of secondary particle formation but tend to omit important aspects of secondary aerosol formation associated with O_3 photochemistry. EPA applied the Community Multi-scale Air Quality (CMAQ, Binkowski and Roselle 2003) model for its updated analyses of the Clean Air Interstate Rule (CAIR) for $PM_{2.5}$ (70 Fed. Reg. 25162 [2005]) and the CAMx model (ENVIRON 2005) for O_3. Receptor-oriented source apportionment models have also been applied to determine contributions from industrial and other sources (Chow and Watson 2002; Watson and Chow 2004).

Although existing models have some important limitations and greater uncertainties are anticipated for secondary PM and O_3 concentrations as compared with directly emitted PM, SO_2, and NO_x, these models likely perform better for estimating population-health benefits over long time-frames than for estimating concentration effects for specific hours at specific receptor locations, because some of the model uncertainties (related to wind direction) may cancel out for aggregate risk estimates. Given the possibility that the NSR rule changes will lead to shifts in the location of emissions with a smaller influence on total national emissions (Chapter 6), it is important to understand the influence of location on pollutant fate and transport and on public-health effects. The CAIR modeling did that for eastern states by determining incremental changes in O_3 and $PM_{2.5}$ in downwind states owing to emission reductions in upwind states and serves as a good example of how models can be used to evaluate the effects of emission reductions.

Geographic location can have three major influences. First, meteorological conditions—such as temperature, humidity, wind speed and direction—can influence the fate and transport of a pollutant, including the rate at which SO_4, NO_3, SOA, and O_3 are formed and their dispersion. Second, ambient pollution at downwind sites will influence not only atmospheric chemistry but also attainment-nonattainment status. Third, population patterns at downwind sites will influence the magnitude of the public-health effects of emission changes. In addition, pollutant fate and transport will be affected by such facility characteristics as stack height and diameter, pollutant exit temperature and velocity, and other site characteristics, so differentiating among sources and source categories is important.

Addressing the first point, different factors will influence formation of SO_4, NO_3, and O_3. SO_2 can be converted to SO_4 through reactions in gas and aqueous phases and to a lesser extent in the aerosol phase (Seinfeld and Pandis 1998). In the gas phase, SO_2 is oxidized in the presence of the OH radical; higher formation rates are found with greater solar radiation intensity. Thus, SO_4 formation is greater in the presence of sunlight (during the daytime and during the summer), so diurnal and seasonal emission trends are important to understand. Aqueous-phase SO_4 formation occurs in cloud water, and this can be the dominant route of SO_4 formation in some geographic settings (such as the northeastern United States). NH_3 availability will have some importance; in low-NH_3 environments, aqueous-phase sulfuric acid will be the dominant form of SO_4 aerosol, whereas in NH_3-rich environments, sulfuric acid is neutralized to form ammonium sulfate (Seinfeld and Pandis 1998).

Although oxidation of NO_2 via the OH radical is a route of formation, formation of ammonium nitrate aerosol will depend on the relative ambient concentrations of SO_4, NO_3, and NH_3. NH_3 will preferentially react with sulfuric acid over nitric acid. In areas where NH_3 concentrations are low, most of the NO_3 exists as gas-phase nitric acid that is not part of $PM_{2.5,}$ but in NH_3-rich locations, all the sulfuric acid is neutralized and remaining NH_3 reacts with nitric acid to create particulate ammonium nitrate (Seinfeld and Pandis 1998). Owing to that interaction, there are geographic settings in the eastern United States where SO_2 emission reductions may result in decreases in $PM_{2.5}$ ammonium sulfate but increases in $PM_{2.5}$ ammonium nitrate (Ansari and Pandis 1998).

From the perspective of the effects of the NSR rule changes, the implication is that SO_2 or NO_x emission changes could have different effects on $PM_{2.5}$, depending on where the emissions occur. In general, the Northeast, Ohio, and Pennsylvania tend to be sulfate-rich, in large part because they are downwind from coal-fired power plants. NO_x emission reductions in those areas may not lead to substantial reactions in $PM_{2.5}$ concentrations, because there would be inadequate NH_3 to react with nitric acid. But in the plains states of the Midwest, concentrations of NH_3 are high and SO_4 concentrations lower, so NO_x reductions might result in reductions in $PM_{2.5}$ ammonium nitrate concentrations. $PM_{2.5}$ travels hundreds or thousands of kilometers, so the plume from a given source may travel through multiple regimes.

For O_3, the influential factors and geographic patterns are somewhat different from those for secondary $PM_{2.5}$ sulfate and nitrate. As indicated in Figure 7-6, O_3 is formed in a complex atmospheric cycle involving NO_x and VOCs in the presence of sunlight. The O_3 formation process is highly nonlinear; with high background concentrations of VOCs relative to NO_x, reductions in NO_x may lead to lower O_3 concentrations. In settings with high NO_x concentrations relative to VOCs, NO_x emission reductions tend to increase O_3 concentrations. In general, higher VOC concentrations tend to lead to more O_3 (or little change in O_3), and higher NO_x concentrations may either increase or decrease ambient O_3. Because NO_x is emitted by motor vehicles in large quantities, urban areas tend to be high in NO_x, and urban NO_x emission reductions may increase local O_3, although the reductions may result in decreased O_3 concentrations at more distant locations. Similarly, in nonurban areas, NO_x concentrations are lower and biogenic VOC emissions may be higher (especially in eastern states), so reductions in NO_x would tend to decrease O_3 concentrations. Thus, the urban-rural status of an emission source will have an important effect on the magnitude and direction of O_3 concentration changes.

To summarize, air-quality models show that the geographic location of an emission source, as well as the emission height and seasonal or diurnal emission patterns, can influence O_3 and secondary $PM_{2.5}$ formation rates. It is therefore critical to understand where emission sources affected by the NSR rule changes are (including region and urban-rural status) because their locations will influence the magnitude and even direction of the effects. As explained in earlier chapters, models simulate decision-making processes or sectoral-level responses, but they may lack adequate input data or model resolution to be able to appropriately characterize geographic shifts in emissions. Without adequate estimates of the geographic patterns of emission changes, air-quality models cannot provide reliable estimates of changes in ambient concentrations owing to the NSR rule changes.

AMBIENT CONCENTRATIONS

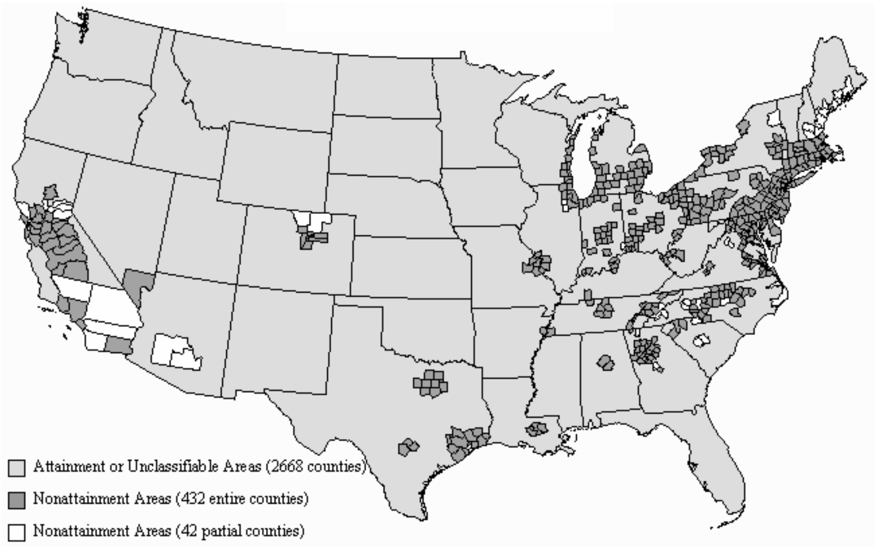
Ozone and $PM_{2.5}$ NAAQS Nonattainment Areas

A second influence of geographic location involves whether downwind sites are in nonattainment of NAAQS. The background concentration could be influential in health benefits estimation for cases where there may be population health effects from exposure concentrations below the NAAQS, or where the effect of a change in concentration would differ depending on the background concentration (i.e., a nonlinear concentration-response function). Figure 7-7 shows the extent of U.S. nonattainment areas for O_3 and $PM_{2.5}$. Areas where the O_3 standard is exceeded cover multiple counties in central and Southern California; Las Vegas, Nevada; Phoenix, Arizona; along the Colorado Front Range; the Houston, Dallas, and San Antonio areas in Texas; and much of the midwestern and eastern United States. Nonattainment areas for the annual average $PM_{2.5}$ NAAQS are primarily in California and the eastern United States. Comparing these distributions with the fraction of precursor emissions that are potentially affected by NSR in Figures 7-1 and 7-3 indicates that the midwestern, southern, and northeastern states would be most likely to have NSR-eligible sources contributing to NAAQS violations. In many western states, emission changes resulting from NSR rule changes probably have a minimal effect on NAAQS attainment status although some sources may contribute to downwind NAAQS violations. The nonattainment status of much of Southern California indicates that the contribution from point sources should not be discounted. In many of those states, the changes may be more important for future emission reductions related to regional haze (Watson 2002).

Composition of $PM_{2.5}$

Although the combination of emission inventory data and attainment-nonattainment status provides some insight into geographic patterns, it does not directly address the relative source contributions in a specific geographic area. $PM_{2.5}$ composition and its variation in space and time can be used to identify the importance of different source contributions. A comparison of Figure 7-8 a and b shows that many of the urban sites contain a larger component of carbonaceous particles than the nonurban sites, probably because of more abundant primary emissions from traffic and fuel use. The exception is the large nonurban (and urban) carbon fraction in the Pacific Northwest due to extensive wildfires during summer 2002. Sulfate concentrations are much higher in the eastern United States than in the West, and they are similar in nearby urban and regional sites; this is consistent with the distribution of coal-fired power plants in the United States and the long-range transport of SO_4 particles. NO_3 constitutes a larger fraction of $PM_{2.5}$ in the West, especially in California. Particulate NO_3 levels in the eastern United States is low but may increase if SO_2 reductions free NH_3 for reaction with nitric acid that would increase ammonium nitrate, as described above. Nevertheless, review of a large number of studies (Watson 2002) demonstrates that SO_4 decreases with reductions in regional SO_2 emissions.

(a)



(b)

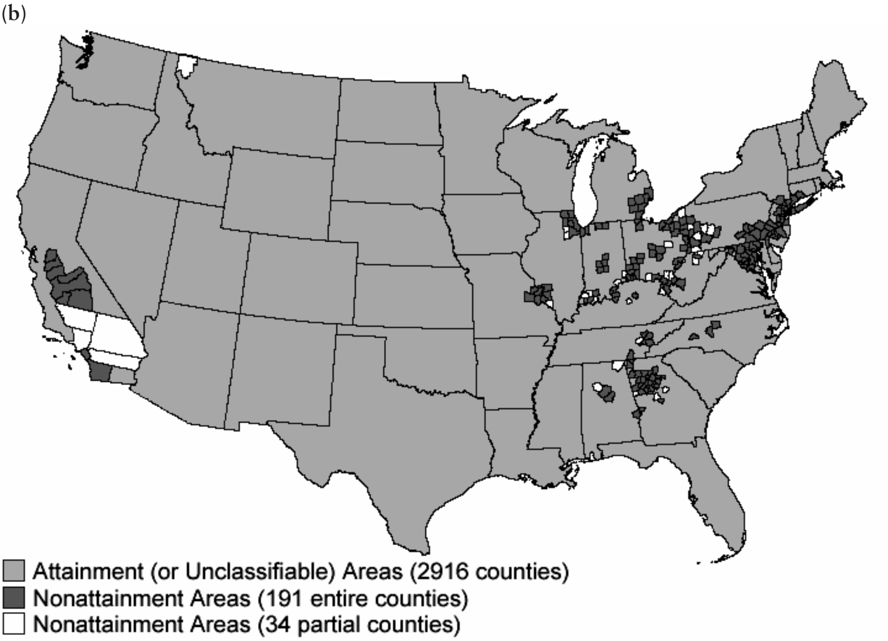


FIGURE 7-7 (a) O_3 nonattainment areas for 2004 based on the 8-hour NAAQS. SOURCE: EPA 2004o. (b) $PM_{2.5}$ nonattainment areas for annual average $PM_{2.5}$ NAAQS. SOURCE: EPA 2004p.

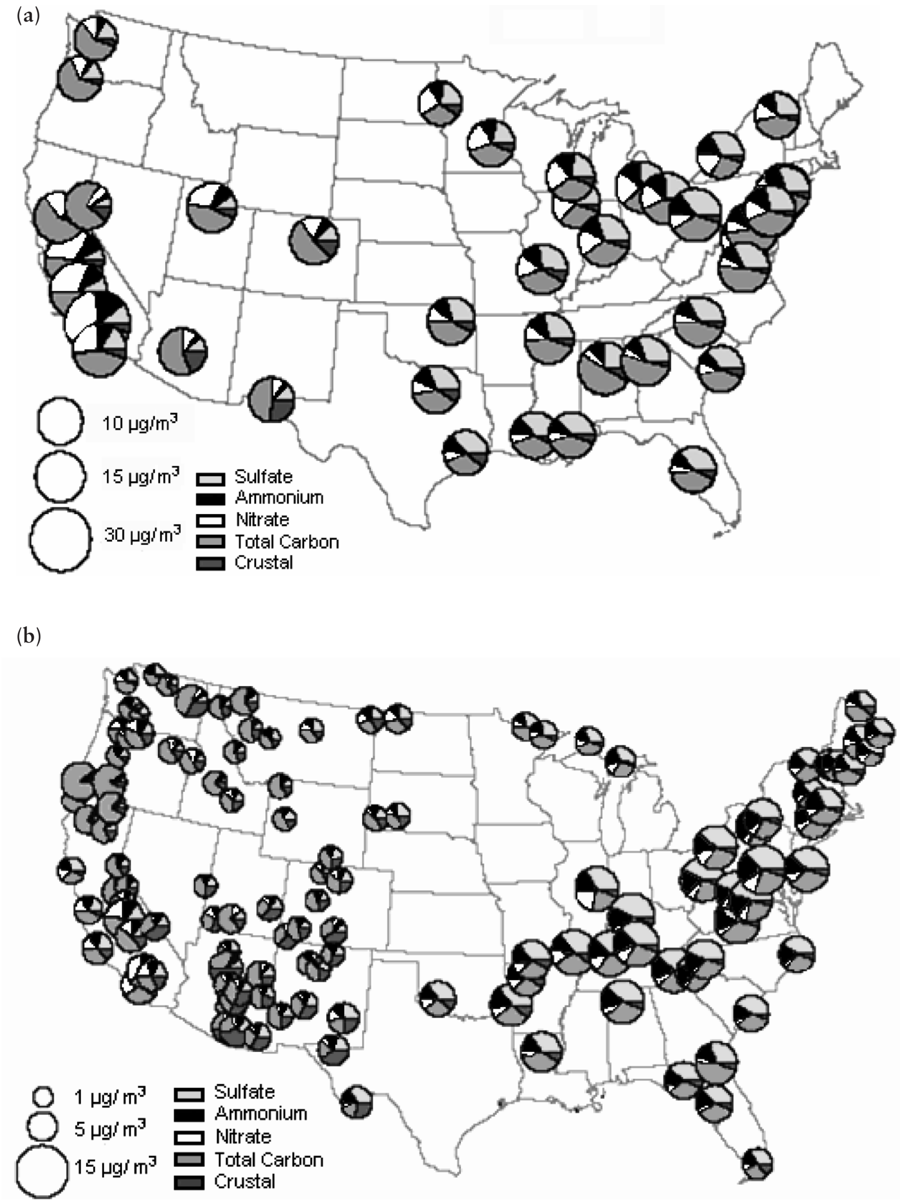


FIGURE 7-8 2002 annual average $PM_{2.5}$ chemical composition at (a) urban sites in EPA's Speciation Trends Network (STN) and (b) EPA's Interagency Monitoring of Protected Visual Environments (IMPROVE) network. SOURCE: EPA 2003e.

HEALTH EFFECTS

The final step in understanding the health effects of changes in emissions would involve quantifying the effects of the modeled ambient concentration changes on a variety of health outcomes. Nonattainment areas indicate where the air is deemed unhealthful according to the current NAAQS (Table 2-1), but NAAQS are periodically revised in response to discoveries about air pollution and health effects and epidemiological evidence may indicate that non-zero health effects occur below currently promulgated standards. To evaluate health benefits of changes in emissions, a standard health-benefits analysis framework has been endorsed by the National Research Council (NRC 2002) and applied by EPA (1999, 2004l), the World Health Organization (WHO 2002a,b), the World Bank (Van Beukering et al. 2002), and many independent investigators. A comprehensive evaluation of the framework is beyond the scope of this report. Instead, the committee focuses on a few critical dimensions relevant to the effects of the NSR rule changes. First, as in our interim report, we provide brief descriptions of the status of health concerns associated with the criteria pollutants, except lead.[1] In addition, summary information is given for several VOCs, which are also regulatory targets but are managed differently from the criteria pollutants.[2] The objectives of this review are to determine which pollutants have been associated with health effects at current ambient concentrations and to consider more broadly the extent to which health effects can be attributed to single pollutants (a necessary step in health-benefits analysis). Second, the likelihood of nonlinearity in the concentration-response functions is discussed to determine geographic locations in which health benefits might be anticipated. Finally, the influence of the geographic location of sources on the potential health effects of changes in emissions is evaluated by addressing pollutant fate and transport, population patterns, and the shapes of the concentration-response functions.

A large and growing body of published epidemiologic and toxicologic research, as summarized in EPA criteria documents cited below, establishes that the criteria pollutants are associated with a variety of health effects, including increased occurrence of cardiopulmonary morbidity, cardiopulmonary and cancer mortality, effects on birth outcomes (low birth weight and infants that are small for gestational age), and impaired growth of lung function in children. The associations are most consistent in children (particularly those with asthma) and the elderly (particularly those with

[1]Lead is not included in this review, because ambient concentrations of lead have decreased precipitously since it was removed from gasoline. A small number of stationary sources (such as smelter and battery plants) are the primary sources of lead emissions in the atmosphere.

[2]The committee does not discuss the detailed published data related to the effects associated with various VOCs.

underlying cardiovascular diseases and diabetes). In contrast with the clarity of the overall associations, the extent to which the various health effects can be attributed to a given pollutant or combination of pollutants is less clear; this limitation must be considered in examining the quantitative estimates of association attributed to any single pollutant. In the case of PM, the problem is compounded by the fact that PM is a complex physical-chemical mixture whose components probably interact with other criteria pollutants (such as O_3) in ways that may affect health outcomes. Characterizing an overall pollutant mixture with respect to its health implications is a major future challenge for air-pollution-related health-effects research.

Carbon Monoxide

Concerns about the health effects of inhaled CO have focused on the various manifestations of its greater affinity than that of oxygen for binding to blood hemoglobin, thereby reducing blood oxygen concentrations. Accordingly, the current NAAQS for CO is based on preventing significant health effects by limiting blood carboxyhemoglobin concentrations (in normal nonsmokers) to about 2% or less (EPA 2000). The health effect driving the current NAAQS is angina (chest pain) in exercising people who have coronary arterial disease. The onset of angina signals ischemia (lack of sufficient oxygen) in heart muscle and not only limits the level and duration of exercise but also can increase the risk of arrhythmias and death.

Epidemiologic research since the last review of the CO NAAQS has provided some evidence of associations between increases in CO concentrations and increased cardiopulmonary mortality and morbidity. Several studies focused on PM, but multipollutant models also appeared to show significant relationships between CO and mortality (EPA 2004h). Some studies suggest that in such cases CO serves as a marker of mobile-source contributions of several pollutants and perhaps even as a surrogate of toxic $PM_{2.5}$ (supposedly, that emitted directly from combustion sources). Whether CO affects mortality directly or serves as an indirect indicator of exposure to other toxicants is not resolved; however, the statistical link between CO and mortality cannot be disregarded.

Recent research has demonstrated statistical associations between ambient CO and low birth weight (Ritz and Yu 1999). The finding has not been replicated sufficiently to evaluate either exposure-response relationships or the specificity of the effect of CO confidently, but the evidence warrants concern.

CO can also exert central nervous system effects, including reductions in hand-eye coordination (driving or tracking) and in attention and vigilance. Available data, however, suggest that ambient concentrations are unlikely to cause such effects unless ambient exposures are superimposed on exposures from other sources, such as heavy smoking or hot spots caused by extreme traffic emissions (EPA 2000).

Nitrogen Oxides

As described above, NO_x commonly refers to the sum of NO and NO_2. The symbol NO_y commonly refers to the sum of NO_x and other oxidized nitrogen compounds, such as nitric acid. Nitrous oxide is commonly excluded. NO and NO_2 have numerous sources, especially combustion emissions, and are present in ambient air in greater concentrations than the other species. NO_2 is toxic by virtue of its oxidation potential and has received the greatest health-research and risk-assessment attention. NO has lower toxicity but is increasingly recognized as a mediator or intermediate of cellular signaling and biochemical processes, both beneficial and detrimental. NO_y is of concern not only for its toxicity but also because of its participation (with VOCs and sunlight) in the formation of O_3 and secondary PM (nitrates).

NO_x constituents are oxidants and thus may contribute to the wide range of respiratory health effects thought to be associated with inhaling oxidants or mediated by oxidation pathways. Experimental and accidental inhalation of NO_2 at high concentrations has been shown to cause respiratory symptoms (such as cough and wheezing), reduced lung function, and increased airway responsiveness in both healthy and asthmatic people. The evidence of those effects at common ambient concentrations (less than 0.05 ppm based on an annual average) is equivocal (EPA 1995c). Among the many recent epidemiologic studies of the effects of particles and copollutants on respiratory and cardiovascular outcomes, NO_x has seldom arisen as an important factor. Prolonged high exposures of animals (for example, at 10 ppm and higher) have caused emphysema-like changes in some, but not all, studies. Tissue changes are unlikely at ambient exposure concentrations; however, the recent finding that ambient exposure to O_3, also an oxidant gas, affects lung development suggests the possibility that NO_x contributes to similar effects. High indoor exposures of children (often associated with gas-stove use) have been linked to reduced resistance to respiratory infections and increased likelihood of respiratory illness (Hasselblad et al. 1992), including wheezing and persistent coughing (van Strien et al. 2004). In addition, recent evidence suggests that NO_2 exposures increase the severity of virus-induced asthma exacerbations (Chauhan et al. 2003). Although it is unconfirmed, NO_x emissions might contribute to the associations between respiratory illness in children and proximity to heavily traveled roadways (Wjst et al. 1993; Oosterlee et al. 1996; Brunekreef et al. 1997).

Research since the last review of the NO_2 NAAQS indicates that NO_x may retard lung growth in children (Gauderman et al. 2004). Differences between the rates of lung growth in children living in areas of higher and lower pollution were statistically associated with NO_2 and with airborne acid and $PM_{2.5}$, substances to which NO_x contributes. NO_2 (and other air pollutants) also may increase airway responsiveness to allergens (Rusznak et al. 1996; Jenkins et al. 1999).

Although probably NO_x contributes to the effects of air pollution on public health, it is likely that NO_x species affect health more through their contribution to the formation of O_3 and secondary PM than through their direct effects.

Ozone

O_3, like PM, is one of the criteria pollutants of greatest health concern. There is little doubt that public health is measurably affected by exposures that occur in many areas in the United States (EPA 1996).

O_3 is an oxidant gas emitted directly from sources (such as electric motors) in only small amounts. Ambient O_3 is formed in the atmosphere overwhelmingly by reactions involving NO_x, VOCs, and ultraviolet radiation (sunlight) (see Figure 7-6). It is one of several photochemical oxidants. In the respiratory tract, O_3 interacts with polyunsaturated fatty acids, electron donors (such as ascorbate and vitamin E), and the thiol, aldehyde, and amine groups of low-molecular-weight compounds and proteins. O_3 is very reactive, and its most harmful biologic effects probably result from the products of initial reactions with surface fluids and cell walls rather than from direct interactions with intracellular targets. In people who have chronic obstructive pulmonary disease or asthma, the antioxidant content of the lung lining can be reduced, potentially contributing to increased sensitivity to O_3 (Mudway and Kelly 2000).

O_3 has been associated with an array of adverse effects, but the effects primarily driving the current standard are pulmonary function decrements in exercising children, adolescents, and susceptible (for example, asthmatic) people. O_3 causes a neurogenic (reflex) inhibition of maximal inspiration that reduces maximal forced expiratory volume during lung-function tests and ventilatory capacity during exercise. O_3 also causes increased airway responsiveness (constriction) to other materials (such as airway-constricting drugs and allergens). Although the degree of increased responsiveness may not differ much between healthy and asthmatic people, the much greater baseline responsiveness of asthmatic people makes the O_3-induced additional decrement potentially more serious. High O_3 is associated with increased clinic visits and hospitalization of people with asthma and other pre-existing respiratory diseases; there is also some evidence of increased mortality among these populations (Thurston and Ito 2001; Bell et al. 2004).

O_3 also acts as a respiratory and eye irritant, giving rise to noticeable, if not life-threatening, discomfort that limits activity and reduces quality of life. It may impair defenses against respiratory pathogens and inhaled particles. There is evidence (EPA 1996) that O_3 slows the clearance of particles from the lungs by damaging cilia and retarding the activity of macrophages; however, it is not clear whether this occurs in humans at actual exposure concentrations. Furthermore, Pope et al. (2002) observed an association between long-term exposure to summertime O_3 and increased risk of premature death in cohort studies, although the relationship was not statistically significant. Bell et al. (2004) found a statistically significant association between short-term changes in O_3 and average mortality in 95 large U.S. urban communities. Three recent meta-analyses (Bell et al. 2005; Ito et al. 2005; Levy et al. 2005) supported findings of increased mortality associated with daily changes in O_3 concentrations.

Research since the 1996 O_3 criteria document (EPA 1996) reviews indicates that O_3 retards lung growth. Exposures of animals have produced alterations in the development of lung structure during growth (Schelegle et al. 2003). Epidemiologic studies have demonstrated that entering college students from areas with high O_3 concentrations have smaller lungs and lower lung function than students from areas with low O_3 (Kunzli et al. 1997) and that long-term exposure to O_3 is associated with decreases in measures of small-airway function (Tager et al. 2005).

Suspended Particulate Matter

PM encompasses a physically and chemically diverse class of ambient air pollutants of both anthropogenic and biologic origin. The PM standard is the only NAAQS that does not target a specific chemical or family of chemical species. PM concentration is defined functionally as the change in mass of a filter through which ambient air is drawn under standardized conditions. PM can be solid, liquid, or composed of semivolatile species (partitioned between the PM and vapor phases, depending on ambient conditions), and it can be either directly emitted from sources (primary, such as fly ash) or formed in the atmosphere (secondary, such as SO_4) from precursor gases. Regardless of composition, the aerodynamic size of PM determines its ability to enter the mouth or nose and the distribution of fractional deposition throughout the respiratory tract (EPA 2004h). There is no exclusive difference in the ability of PM of any aerodynamic diameter of 10 μm or less to reach different parts of the respiratory tract; both 10-μm and 10-nm particles could be deposited in the nose or the deep lung. However, the probability of deposition in different locations varies considerably with size. Most inhaled PM of a typical ambient size distribution is not deposited at all but is exhaled (EPA 2004h); however, there is clear evidence that the portion that is deposited can exert adverse health effects if the exposure is sufficient.

A large array of health effects have been associated with exposure to PM in both epidemiologic and laboratory studies. The current $PM_{2.5}$ NAAQS (62 Fed. Reg. 38651 [1997]) was based on epidemiologic evidence of mortality. The concerns about human health effects associated with ambient PM or demonstrated in laboratory studies have expanded from earlier concerns about total mortality and respiratory morbidity to include cardiac mortality and morbidity, blood-vessel constriction, stroke, premature birth, low birth weight, retarded lung growth, enhancement of allergic responses, reduced resistance to infection, degenerative lesions in the brain, and lung cancer (EPA 2004h).

Both short-term increases in PM exposure and longer-term exposure concentrations are of concern. Numerous time-series studies have correlated variations in ambient PM with concurrent or lagging variations in health outcomes; other studies have demonstrated differences in mortality and morbidity between populations with different long-term PM exposures (Dockery et al. 1993; Pope et al. 1995, 2002, 2004). The relationship between the effects of short-term spikes in exposure and the cumulative effects of longer-term exposure to both spikes and baseline concentrations is uncertain.

The quantitative relationship between PM exposure and health effects remains uncertain, as does the proportion of the criteria-pollutant health effects attributable to PM copollutants. Despite the uncertainties and the attendant debates, it seems clear that current concentrations in some areas and at some times in the United States are associated with health burdens that warrant concern, and a causal interpretation of the epidemiologic evidence implies a public-health burden from PM exceeding that from other criteria air pollutants (EPA 2004h).

The relationship between PM composition (particle size fractions and chemical components) and adverse health effects remains uncertain. The current PM NAAQS assumes that all PM mass is of equal toxicity, but it is unlikely that the mechanisms of action and relative toxicities do not differ across constituents. Different PM components (such as metals and organics) drive different types of toxicity (some components are more toxic than others for some effects), and the same PM composition administered in different particle sizes has different potencies. However, there has been insufficient systematic study of the effects of composition and size differences on the different effects of concern on which to base composition-specific standards. In part, size is incorporated into the NAAQS as a rough surrogate of composition (because most fine PM stems from the combustion of fossil fuel or biomass, whereas coarse particles tend to arise from fugitive dust, pollens and spores, and sea salt). However, particles of similar size can have vastly different origins and composition. An extensive discussion of the weight of evidence for differential toxicity of key particle constituents (that is, sulfate, metals, and organic carbon) is beyond the scope of this report, but the recent particulate matter criteria document (EPA 2004h) contains some relevant information. In particular, EPA came to the conclusion that the information is insufficient at the present time to clearly identify the high-risk chemical components of $PM_{2.5}$, beyond an apparent differentiation between combustion and noncombustion particles.

Sulfur Dioxide

SO_2 is of concern both because it is a direct respiratory irritant and because it contributes to the formation of SO_4 and sulfuric acid in PM. The current NAAQS for SO_2 is based primarily on preventing airway constriction in exercising, unmedicated asthmatic people (EPA 1994e). People with asthma are of particular concern both because they have increased baseline airflow resistance and because their SO_2-induced increase in resistance is greater than that in healthy people and increases with the severity of their asthma. SO_2 is thought to induce airway constriction via neural reflexes involving irritant receptors in the airways; the NAAQS is aimed at preventing stimulation of these reflexes in people with asthma.

Epidemiologic research since the last review of the SO_2 NAAQS (Krewski et al. 2000; Pope et al. 2002) has repeatedly demonstrated associations between ambient SO_2 and cardiopulmonary morbidity and mortality. Studies focused primarily on PM have often demonstrated significant or near-significant statistical associations between SO_2 and the health outcomes. The implications of those findings are unclear. As a respiratory irritant, SO_2 probably contributes directly to respiratory morbidity, and it might contribute directly to mortality of respiratory origin. Through neural reflexes, it is possible that SO_2 also might contribute directly to cardiac arrhythmia and thus cardiac morbidity and mortality, but this possibility has not been explored in controlled studies.

To the extent that ambient concentrations of SO_2 are linked to concentrations of particulate SO_4 and airborne acid at the same location, SO_2 also might be serving as a marker of ambient SO_4 (and thus ambient fine PM), which might cause the effects. However, until we have a better understanding of the specific physical-chemical air-pollutant species causing cardiopulmonary morbidity and mortality, we cannot ignore the possible direct contribution of SO_2.

Volatile Organic Compounds

In addition to the criteria pollutants, emissions addressed by the NSR program include a diverse group of VOCs. VOCs encompass an array of chemical species that have in common a fundamental organic structure (primarily hydrocarbons, including oxidized and substituted hydrocarbons), a presence primarily or entirely in the gas phase under ambient conditions, and a reactivity that leads to participation (with NO_x and sunlight) in atmospheric reactions that result in the formation of O_3. Because of research on the role of VOCs in the formation of O_3 and efforts to identify and control emissions of its most reactive precursors, VOCs have long been targeted as a group to be regulated (EPA 1996). VOC emissions also contribute to the formation of airborne PM. The major classes of VOCs are alkanes, alkenes, aromatics, carbonyls, alcohols, and ethers. The substances included in VOC measurements can vary; some measurements target specific species, and others encompass multiple substances (such as total nonmethane hydrocarbons).

Although VOCs are addressed by NSR because, as precursors of O_3, they contribute to health and welfare effects, many members of the group are also of concern because of their toxicity. Those considered to have the most important primary health implications are also included within the regulatory group termed hazardous air pollutants (HAPs, also known as toxic air pollutants or air toxics). The Clean Air Act lists 188 HAP species or classes. In its most recent National-Scale Air Toxics Assessment, EPA reviewed 32 of the 33 HAPs it identified in 1999 to be of greatest concern in urban areas plus diesel PM (EPA 2002f). EPA terms the 33 key HAPs urban air toxics (64 Fed. Reg. 38706 [1999]) (see Table 7-2). Examples of VOC HAPs are benzene, which is found in gasoline; methylene chloride, which is used as a solvent and paint stripper by a number of industries; and perchloroethlyene, which is emitted from some dry-cleaning facilities. The health effects of VOC HAPs differ among the species; summaries can be found at EPA (2004n). Most effects of concern involve mutagenicity, cancer, irritation (inflammation), neurotoxicity, or modulation of immune responses.

Health Effects of New Source Review Changes

The evidence presented above provides some insight into the complexity of quantifying the health effects of changes in ambient air pollution. O_3 and $PM_{2.5}$ have shown the strongest associations with health outcomes at current ambient concentrations. In light of that and findings from our earlier evaluation of emission data and from consideration of attainment-nonattainment status, the committee recommends that future analyses of the national-level effects of NSR rule changes focus on those pollutants and their precursors. However, both pollutants may represent indexes rather than single causative agents. For example, O_3 exerts its effects through its oxidative properties, and other photochemical oxidants may have similar effects. PM, as a combination of constituents, may have effects that depend on its composition and on the concentrations of copollutants. Estimation of

TABLE 7-2 Urban Air Toxics

Acetaldehyde[a]	Coke-oven emissions	Mercury compounds
Acrolein[a]	1,3-Dichloropropene[a]	Methylene chloride[a]
Acrylonitrile[a]	Dioxin	Nickel compounds
Arsenic compounds	Ethylene dibromide[a]	Perchloroethylene[a]
Benzene[a]	Ethylene dichloride[a]	Polychlorinated biphenyls (PCBs)
Beryllium compounds	Ethylene oxide[a]	Polycyclic organic matter
1,3-Butadiene[a]	Formaldehyde[a]	Propylene dichloride[a]
Cadmium compounds	Hexachlorobenzene[a]	Quinoline[a]
Carbon tetrachloride[a]	Hydrazine[a]	1,1,2,2-tetrachloroethane[a]
Chloroform[a]	Lead compounds	Trichloroethylene[a]
Chromium compounds	Manganese compounds	Vinyl chloride[a]

[a]Also a volatile organic compound (VOC).

SOURCE: 64 Fed. Reg. 38706 (1999); EPA 2004f.

the health effects of NSR rule changes may depend on the extent to which changes in concentrations of individual components are useful surrogates of changes in the pollutant mixtures to which populations are exposed. In any case, a focus on O_3 and $PM_{2.5}$ is probably the best approach for a first approximation of health benefits. Because many of the aforementioned uncertainties are unlikely to be resolved in the near term, that will probably be the approach that will need to be used in upcoming evaluations of NSR rule changes.

Shape of the Concentration-Response Functions

Given the committee's focus on PM and O_3, we can consider the second question mentioned above, which addresses the shape of the concentration-response functions. That would influence the magnitude of health benefits anticipated from changes in concentrations in different geographic locations and is important in determining whether health effects would be anticipated in NAAQS attainment areas or, more generally, whether incremental concentration changes would have a greater effect in some locations than in others. There is general agreement that detection of thresholds for various pollutants is difficult with population data because such data represent weighted averages (weights unknown) of pollutant-host interactions. By and large, the body of personal-exposure data is insufficient to determine pollutant thresholds precisely.

For PM, although epidemiologic evidence has not shown a threshold for mortality effects (Pope et al. 2002; Daniels et al. 2004), epidemiologic studies lacking accurate personal-exposure data have a limited ability to detect thresholds if they exist. Furthermore, although animal studies have provided insight into mechanisms of response and confirmed the toxicity of some PM components, few statistically significant responses have been demonstrated in the laboratory at ambient exposure concentrations. The most recent EPA staff paper on the review of the PM NAAQS (EPA 2005f) concludes that although there are probably individual biologic thresholds for specific health responses, studies do not support or refute the existence of thresholds in PM-mortality relationships at the population level. Given that uncertainty, regulatory impact analyses typically use a no-threshold assumption for a base case but evaluate the sensitivity of conclusions to that assumption (EPA 1999). Similarly, for O_3, although the National Morbidity, Mortality, and Air Pollution Study (Bell et al. 2004) finds a similar relative risk for O_3 above and below the NAAQS, differences between personal O_3 exposures and ambient concentrations make it difficult to detect thresholds (Zhang and Lioy 1994; Brauer et al. 2002).

From the perspective of the NSR rule changes, future analyses should consider whether policy conclusions are sensitive to assumptions about thresholds and other nonlinearities. Such analyses should consider a variety of population thresholds other than the NAAQS, especially because the $PM_{2.5}$ NAAQS could be revised in coming years on the basis of evidence of effects at lower ambient concentrations (EPA 2005f). The analyses should also take account of the likelihood that imposing a threshold on observational data that appear linear would result in a higher slope above the threshold (a so-called hockey stick concentration-response function). Thus, although it is more likely that health effects would be observed at higher ambient concentrations, there is no specific evidence that health effects are isolated to nonattainment areas. The geographic patterns of health effects could also be influenced by geographic clustering in the prevalence of susceptible people (asthmatics and diabetics). Available data are generally too sparse for such an assessment, although significant urban-rural differences may be present for multiple health outcomes of interest.

Because of difficulties in linking health outcomes exclusively with O_3 and PM and because of a lack of definitive evidence regarding the shape of the concentration-response function (especially at low concentrations), there would be substantial uncertainties in quantifying health outcomes associated with NSR rule changes even if concentration changes were quantified. However, if the same assumptions are used for all emission scenarios to be compared, the relative effects of different strategies are likely to be appropriately ranked, and the analyses will provide order-of-magnitude estimates that can be used to determine whether more-refined information would be needed to choose among policy options.

Influence of Geographic Location of Sources on Potential Health Effects

Our final question is related to the population health effects associated with emission changes. A relevant calculation would integrate atmospheric fate and transport with population patterns and ambient concentrations downwind of sources. Formally incorporating the above uncertainties in health effects is beyond the scope of this report, but under a working assumption of a linear concentration-response function for O_3 or PM, some estimates from the literature can provide insight into the degree to which the relationship between emissions and total population exposure varies spatially or temporally. By total population exposure, we refer to the summation of incremental concentration changes across the population, multiplied by the affected population, which would give a value proportional to health benefits in the event of a linear concentration-response function. For example, Mauzerall et al. (2005) used the CAMx model of the relationship between NO_x emissions and O_3 concentrations from point sources in different locations and under different meteorologic conditions and followed a health-benefits analysis framework. They found that health benefits per unit of NO_x emission reductions were twice as high during a high-temperature episode relative to a low-temperature episode and that health benefits per unit of NO_x emission reductions were more than twice as high for a source in Maryland as for a source in North Carolina (in spite of 1-hour maximum O_3 concentrations that were more than twice as high in North Carolina). The latter differential was attributed to downwind population density. In a follow-up study, Tong et al. (2006) evaluated the ozone-related exposure and health effects associated with additional NO_x emissions in various source counties around Atlanta, Georgia. They determined that the aggregate effects were negative for source counties near the city center and positive for rural source counties. The negative impacts for urban emissions were attributed to local ozone scavenging in the domain where population density was greatest. This modeling illustrates the substantial spatial variability in health benefits per unit emission reductions, especially for secondary pollutants. Similarly, Wilson (2003) used a source-receptor matrix to determine the relationship between NO_x, SO_2, and primary PM emissions and population exposures to $PM_{2.5}$, considering 507 power plants across the United States. He found that total population exposure (the product of population and incremental concentration changes) to ammonium sulfate per unit of SO_2 emissions varied by a factor of 10 and population exposure to $PM_{2.5}$ ammonium nitrate per unit of NO_x emissions varied by a factor of 40 among sites. Similar variability has been reported elsewhere (Evans et al. 2002; Zhou et al. 2006). In all of these studies, as in Mauzerall et al. (2005) and Tong et al. (2006), downwind population patterns as well as meteorology and stack characteristics were important predictors of total population exposure. Both of these analyses clearly indicate that geographic variability in health benefits for a given emission reduction is substantial even under the assumption of a linear concentration-response function with no threshold, and this variability would only increase if nonlinearities were considered.

CONCLUSIONS

The committee draws the following conclusions:

- Nationally, the fraction of total emissions from existing sources that are eligible to be subject to NSR varies by pollutant: for SO_2, 80% is from point sources potentially subject to NSR. For NO_x, 30-40% is from point sources potentially subject to NSR. For primary $PM_{2.5}$ and VOC, little is emitted directly from point sources.
- Electricity-generating facilities, especially coal-fired power plants, dominate SO_2, NO_x, and $PM_{2.5}$ emissions from NSR-eligible sources. It is unclear whether the NSR rule changes would have a greater effect on electricity-generating facilities than on other sectors, and it is unknown whether electricity-generating facilities will dominate the emission changes associated with the NSR rule changes. However, NSR revisions that substantially affect electricity-generating facility emissions would tend to have the greatest effect on point-source emissions in most states.
- NSR-eligible point sources account for a large portion of total emissions in Texas, midwestern, southern, and eastern states but a much smaller portion of total emissions in western states. That is due in large part to the geographic distribution of coal-fired power plants.
- Within the electricity-generating sector, older power generators have higher emission rates than newer facilities and contribute proportionately more to total emissions than to electricity generation. The older facilities are more likely than newer facilities to undergo maintenance, repair, and replacement of key components, so a substantial portion of emissions from the electricity-generating sector are potentially affected by the NSR rule changes.
- On the basis of emissions data, attainment-nonattainment status, and health evidence, O_3 and $PM_{2.5}$ are the criteria air pollutants most likely to contribute to health effects of NSR rule changes, although uncertainties remain regarding the extent to which these pollutants represent indexes rather than direct causative agents.
- Atmospheric fate and transport models constitute the recommended approach to determine the O_3 and $PM_{2.5}$ concentration changes associated with NSR rule changes, but model users should ensure that such models incorporate critical phenomena of O_3 and secondary aerosol chemistry over long downwind distances.

- On the basis of factors influencing O_3 and secondary aerosol chemistry, there will be well-defined geographic patterns in the concentration effects of emission changes in O_3 and secondary PM precursors, including regional patterns for $PM_{2.5}$ based on ambient SO_4, NO_3, and NH_3 concentrations and urban-rural patterns for O_3 based on ambient concentrations of NO_x and VOCs.
- The emissions from regions most affected by NSR vary by pollutant. For SO_2, the relevant regions are the Ohio River valley, the northeastern corridor, and the southern Appalachians. For NO_x, the eastern United States is dominated by NSR sources and shows the same spatial pattern as for SO_2. For VOCs, the pattern is determined primarily by the location of petrochemical industries, along the major waterways, California, the Gulf Coast, the eastern seaboard, the Great Lakes, and the Ohio River valley.
- The regions with the highest SO_2, NO_x, and $PM_{2.5}$ emissions are the same as those where the NSR-controlled sources dominate emissions of these pollutants and their precursors.
- Given those factors and downwind population patterns, health benefits per unit of emission reduction can vary by more than an order of magnitude across sites even if concentration-response functions are assumed to be linear, and the variability could be even greater if thresholds or non-linearity would be present. Understanding geographic patterns of emission changes associated with NSR rule changes would therefore be critical in determining the net public-health effects.

8

Overall Conclusions and Recommendations

The committee considered a number of analytic approaches to evaluate the effects of the New Source Review (NSR) rule changes. As described in more detail below, each of the approaches has its strengths and weaknesses. If any future assessments of the effects of the NSR rule changes are to be made, the committee recommends that both empirical analysis (that is, of permitting data or investment activities) and modeling (that is, of sectoral responses to regulatory changes or air-quality effects of emission changes) be used. The committee concludes that anecdotal information is not a sufficient basis upon which to draw conclusions about the NSR rule changes. Use of anecdotal information by itself is insufficient because there is a wide variety of ways that an operator of a specific facility might respond to changes in the NSR rules, depending on such factors as the type of industry, economic conditions, and other regulations affecting the facility. In addition, it is difficult to ensure that a representative sample across facilities has been obtained and that the information provided is valid. Although anecdotal information could be used to identify the types of investment projects that are being discouraged by NSR requirements, firms could have an incentive to exaggerate such cases and argue for less stringent NSR rules.

Some qualitative information can play a role in future analyses. For example, the committee recommends that qualitative information be collected from firms about their perceptions of the status of the NSR program for specifying future econometric models. However, that information must be collected using formal interviewing protocols and should be collected prospectively on a large and representative sample to ensure that data will be useful. More generally, information from individuals and organizations can be more formally elicited, through Delphi approaches, other types of formal expert elicitation protocols, and other processes that could take qualitative insights from area experts and translate them into useful information for quantitative analysis. If such information is not collected in a formal way on a representative population, it cannot be used as a basis for answering the questions in the committee's charge.

The committee finds that developing an econometric structural or behavioral model of firm-level investment decisions is not feasible for evaluating the effects of the NSR rule changes. To incorporate all effects of the NSR rule changes appropriately, data would be required on investment projects that were carried out, that were considered but never carried out, and that were modified to avoid NSR. Because these last two effects are unobservable, they could be incorporated only by collecting anecdotal information. That approach is not favored by the committee and could not be used in any case for quantitative analyses.

One analytic approach considered by the committee was to analyze NSR permit data, which could be used to determine how NSR permitting activity changed as a result of the rule changes. However, as discussed in Chapter 3, current databases are inadequate for such an analysis. In addition, these data would capture only projects that were actually done, omitting investments that may have been forgone to avoid NSR. If the databases also included minor-construction permit information at the state level for investment projects that no longer needed NSR permits, such analyses might plausibly capture the major effects of the rule changes. However, given the current state of the data, a reduced-form econometric analysis would be needed to capture effects associated with NSR on investment decisions and emissions.

Data on investment activity (such as those contained in the Longitudinal Research Database of the Census Bureau) could theoretically be used to evaluate the rule changes with econometric methods, especially given different dates of implementation of the rule changes among states. Such analyses would not be possible for several years for a number of reasons: the data become available only after a 3-year lag, many states will not be affected by the rule changes until 2006 or later, and investment decisions can take years to be carried out. In addition, although the diversity in the timing of implementation of the NSR rule changes across states facilitates this reduced-form analysis, interpretation is complicated by the geographic clustering of some industry sectors and attainment-nonattainment status. Also, the NSR permit review process could differ across states in speed and predictability, with slow or uncertain permit approval in some states serving as a major discouragement to investment activity. The importance of delaying the investment process could be especially important for facilities other than the electricity-generating sector, whose firms are attempting to respond to rapidly changing business conditions. The committee considers this use of econometric methods to be a promising analytic approach, and the requisite data collection should commence as soon as possible, as described in the recommendations presented later in this chapter. Because of the changes in the enforcement of NSR rules over time, as discussed in Chapter 2, an analysis of historical data on actual and allowable emissions could be linked to information from the time that NSR enforcement was especially stringent. General inferences could then be made about the effects of changes in the stringency of NSR rules on emissions in the future. However, given changing economic conditions and regulatory requirements, this approach is probably not sufficiently sensitive to capture the incremental effects of NSR. Such analyses could be useful prospectively as a complement to bottom-up sectoral simulation models.

Given current data availability, bottom-up sectoral models constitute the primary analytical approach that can be used at present. In principle, these sectoral models are most relevant to the committee's task, because they can theoretically capture the geographic location of emissions changes, necessary for air quality and human health impact assessment. However, the uncertainties in geographically-resolved estimates are likely substantial. As noted later in this chapter, the committee can draw no conclusions from such modeling about the spatial redistribution of power generation emissions under the equipment replacement provision (ERP). In addition, these models have detailed data needs that are not being met and there are many assumptions embedded in the models that may not be realistic depictions of plant-level decision making. The committee considers this approach as an important companion to the econometric modeling described above, although sectoral models are most useful for identifying a range of possible outcomes and providing insights about general relationships rather than specific numerical forecasts. A significant strength of sectoral forecasting models is that they allow for parametric sensitivity analyses, and any future implementation of the Integrated Planning Model (IPM) or related models should carefully evaluate the sensitivity of model outputs to key inputs. Our IPM modeling efforts were only able to evaluate a small number of input parameter assumptions. Some of those assumptions, namely the assumed effect of the NSR rule changes on the rate of retrofits of selective catalytic reduction (SCR) and flue-gas desulfurization (FGD), had an important influence on the outputs of the model, and others (natural gas prices and investment costs for other generation sources) did not.

Regardless of the approach used to determine the effects of NSR rule changes on plant investment behavior and related emissions, atmospheric fate and transport modeling is required to link the emission changes with incremental changes in ambient concentrations. For health-effects assessments, a model is required that can capture detailed meteorologic factors with appropriate geographic and temporal specificity (that is, to capture the transport and fate of emissions from a specific facility at an averaging time relevant for assessing health outcomes). Although such models are complex and contain uncertainties, the errors in estimating average exposure changes across the population associated with a given facility may be somewhat smaller than the errors in estimating the effects of a facility at a specific site, and the former calculation is more relevant to quantification of health effects. In either case, given the importance of secondary PM and O_3 formation in this context, a fate and transport model must be able to model effects over substantial distances (hundreds to thousands of kilometers) and capture relevant aspects of atmospheric chemistry.

Thus, because of issues discussed in this report, the committee concludes the following:

1. The available information is not sufficient to quantify with a reasonable degree of certainty the potential effects of the NSR rule changes on emissions, human health, facility operating efficiency (including energy efficiency), or pollution prevention and pollution control. Modeling analysis provided insights (presented later in this chapter) into the potential effects on national emissions from the electric-power industry.

2. A combination of empirical analysis and modeling would be necessary to quantify the effects of the NSR rule changes and associated uncertainties. Anecdotal information by itself is insufficient to evaluate the changes in performance by a broad range of facilities after the NSR rule changes have been implemented and the effects that might occur as a result of those changes.

3. To carry out the recommended approaches, long-term collection of data and improved modeling techniques will be required. Our methodology and recommendations about necessary data and information and the development of better research methods are as important as the evaluations of this report regarding the 2002 and 2003 rules. Specific recommendations are presented later in this chapter.

POTENTIAL EFFECTS OF THE NEW SOURCE REVIEW RULE CHANGES

Electricity-Generating Facilities

Numerous dimensions of the NSR rule changes were considered by the committee in assessing the effects of the 2002 rule changes and the ERP change promulgated in 2003: the effects on multiple air pollutants regulated under the NSR program—including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOCs), and carbon monoxide (CO)—and exposures to the pollutants and their health effects; the effects on electricity-generating facilities and other industrial sectors; and the effects on pollution-control technology and facility efficiency.

The electricity-generating sector was a primary focus of many of our assessments. That sector, especially coal-fired power plants, dominates national emissions of both SO_2 and NO_x compared with other large stationary sources. Those two pollutants are important contributors to concentrations of ambient PM with an aerodynamic diameter equal to or less than 2.5 μm ($PM_{2.5}$) and NO_x is an important precursor to ozone (O_3), the air pollutants of principal concern from a health perspective. Power plants contribute substantially to point-source $PM_{2.5}$ emissions as well, although primary PM emissions contribute less to ambient $PM_{2.5}$ than do precursor emissions of SO_2 and NO_x. In the committee's evaluation of modification permits from 1997 to 2002, the largest share of permits for and emissions of most pollutants was typically from the industrial class that includes electric, gas, and sanitary services.[1]

The ERP was the primary rule change that could have influenced the electricity-generating sector because several of the 2002 rule changes had applied to electricity-generating sources since the 1992 WEPCO rule (see Chapter 2). However, the ERP had not been implemented because of a judicial stay, and in March 2006 the rule was struck down by the D.C. Circuit Court. Therefore, there is no direct empirical evidence of the effect of the NSR rule changes on the electricity-generating sector. Thus, a bottom-up (engineering economy) simulation model was used to consider the potential effects of the ERP on emissions, facility efficiency, and other key dimensions of the committee's charge on the basis of several key assumptions.[2] The committee used the IPM to evaluate the possible effects of the ERP on emissions of SO_2 and NO_x, relative to previous U.S. Environmental Protection Agency (EPA) policy of prerevision NSR. Although IPM does not include the other air pollutants affected by NSR (such as VOCs, CO, and primary PM), SO_2 and NO_x are probably the power-plant pollutants that would contribute most to air-quality issues and related health effects.

We caution that IPM or similar models cannot be used as the sole basis for predicting the effects of the NSR rule changes on electricity-generating facility emissions. A model like IPM aggregates multiple generation facilities into agglomerated model plants. Hence, it cannot accurately simulate variations in effects at the level of the individual generating unit, so it is

[1]This group includes establishments primarily engaged in the generation, transmission, and/or distribution of electricity or gas or steam. It also includes irrigation systems and sanitary systems involved in the collection and disposal of garbage, sewage, and other wastes.

[2]Despite the invalidation of the ERP, the committee's analytic approach remains relevant to other future changes that would limit NSR's applicability to the electricity-generating sector.

insufficient for estimating local changes in emissions that could affect public health. At best, IPM is a tool for assessing effects of national, or perhaps regional, patterns of emissions, which certainly are important to public health but can hide substantial local variations in effects. Like all power-sector models, there is uncertainty in the estimates from IPM even for assessing broad patterns. Although there are many possible sources of uncertainty in the IPM inputs and structure, two key sources are briefly mentioned here: firms make decisions under conditions of uncertainty, but the model assumes perfect foresight—an unrealistic premise—and it assumes the existence of perfectly competitive markets in which owners of electricity-generating facilities act as profit maximizers that react efficiently to the economic incentives resulting from electricity markets and environmental policies.

Because IPM is not structured to simulate the effects of NSR rule changes directly, some input-parameter assumptions were required to attempt to capture these effects. In general, IPM requires assumptions regarding the representation of decision making in the industry; values of important parameters for fuel costs, plant efficiency, and performance; and relevant environmental policies and enforcement actions. Several assumptions have important implications for the results of this analysis. The key input parameters reflecting this regulatory change are highly uncertain and require subjective judgments. For example, the model must use percentage of capacity scrubbed annually as a proxy for the effect of NSR changes, but there is no quantitive basis for making that prediction. Moreover, the factual assumptions that go into the model represent projections, with varied reliability, of the future.

Unlike EPA's modeling of the ERP in 2003 (EPA 2003c), the runs that we commissioned considered the possibility that EPA's prior approach to routine maintenance would have compelled a significantly greater amount of coal-fired capacity than the ERP to retrofit controls, repower, or retire. That could occur if aggressive NSR enforcement strategies under the prerevision NSR approach resulted in substantial retrofit activities either through settlements or by making it clear to the regulated community that the courts would uphold the approach taken by EPA in pursuing those strategies. Because it was unknown how the prerevision law would have been interpreted in the future, given a split in court decisions, there was no firm baseline against which to evaluate the impact of the ERP. Moreover, it is not possible to judge what scenario would most likely result from NSR policy without the ERP. For instance, the model does not include decisions at the level of the generating unit about projects that might have triggered NSR under prerevision policy.

The committee also considered the impact of the ERP both under pre-2005 regulations (Title IV, enacted as part of the 1990 Clean Air Act

Amendments, and the NO_x state implementation plan (SIP) call of 1998)[3] and under the rules promulgated in 2005—the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule, and best available retrofit technology under the visibility-impairment rule. CAIR, for our purposes, is the most important of the 2005 rules. A set of sensitivity analyses considered the effect of lower costs of noncoal energy sources on the conclusions, and another sensitivity run defined the lowest-cost means of achieving the national emission changes that would occur if essentially all coal capacity without FGD for control of SO_2 emissions and SCR for control of NO_x emissions were retrofitted with best available control technology (BACT). FGD and SCR provide the emission reduction generally required by NSR.[4] Additional sensitivity analyses are recommended by the committee that it could not implement during its study, given budget and time constraints (see Chapter 6).

The committee considered both an NSR-avoidance assumption regarding prerevision NSR compliance (the basis of the previous EPA analysis), as well as assumptions that the prerevision NSR rules would lead to retrofits of pollution-control equipment that would have otherwise not taken place. For the "avoid" assumption, the committee relied on the previous EPA runs, concluding that re-running IPM would not alter the model result that the ERP would have no appreciable effect on national emissions. The IPM runs requested by the committee were used to analyze the assumption in which the prerevision NSR rules would have resulted in significantly more retrofits than otherwise. Under this assumption, the potential effects of the ERP on national emissions from electricity-generating facilities depend on whether CAIR is assumed to be in place or not. The IPM results suggest the following conclusions if indeed the prerevision NSR rules would have compelled significantly more retrofits:

- For SO_2, without implementation of CAIR, the ERP would be expected to result in a moderate decrease in emissions in the first 6 years or so (compared with prerevision NSR) followed by a period of relatively little change in the next 6 years or so. An initial decrease is expected under these assumptions because the ERP would substantially increase the value of the Title IV SO_2 emission allowances making overcomplinace and banking in early years more attractive. However, after the first 12 years, if it is assumed that prerevision NSR rules would have caused all coal-fired electricity-generating facilities to add emission controls, the ERP would be

[3]A program that provides emissions limits to mitigate NO_x emissions that contribute to ozone formation in the lower atmosphere.

[4]The extent of emission reductions that can be accomplished for a proposed new or modified source is based on a case-by-case evaluation.

expected to cause a relative increase (perhaps substantial) in emissions from the electricity-generating sector compared with the prerevison NSR case (see Chapter 6).

- If CAIR is assumed to be implemented, the model estimates minimal differences in total SO_2 emissions between the prerevision rules and the ERP, even if all electricity-generating facilities would have added emission controls under the prerevision rules.
- For NO_x, without implementation of CAIR, the ERP rule changes would be expected to cause an increase in emissions after the first few years; this increase is larger when the prerevision NSR is assumed to compel greater amounts of emission controls.
- If CAIR is implemented, the model estimates a minimal change in NO_x emissions; although after the first 12 years or so, the ERP would be expected to cause a moderate increase in emissions if all facilities would otherwise have added emission controls under prerevision NSR rules.

Although the quantitative conclusions depend on the input parameters and constraints of the model, the qualitative conclusions are logical and probably robust. In the presence of tighter emission caps, the effect of the NSR rule changes is reduced in part because an emission increase at one facility would be offset by a decrease elsewhere. Unless enough retrofit-repower-retire activity would have occurred under the prerevision NSR rules to reduce national emissions below the emission cap, prerevision NSR policy would tend to increase the costs of control without greatly influencing national emissions. That conclusion is based in part on the structure of IPM. IPM by definition is based on economic optimization, so if a total emission cap is the only environmental constraint, the model will find the lowest-cost solution to yield that level. Imposing additional constraints can only increase the cost, given the structure of IPM. In summary, the IPM runs suggest that the promulgation of CAIR, after the establishment of the NSR rule changes, would reduce the chance that the ERP would have adverse effects on national emissions from the electricity-generating sector. However, because of the substantial uncertainties in the IPM results, no firm conclusions can be drawn about the actual effects of the revised NSR rules. (Note that CAIR is subject to judicial review.)

Changes in IPM assumptions concerning natural-gas costs and the investment cost of new renewable and integrated gasification combined-cycle generation do not change our assessment of the potential effects of the ERP on emissions from the electricity-generating sector.

The committee also compared the cost of achieving national emission reductions through aggressive implementation of the prerevision NSR approach with the cost of achieving the same SO_2 and NO_x reductions by lowering the cap on total allowable emissions that is specified in CAIR and making the cap national in scope. (NSR has local objectives as well, as mentioned in Chapter 2, so this comparison, which is limited to national emission reduction, should not be taken as attempting an overall assessment of NSR.) The IPM analysis indicates that even when the prerevision NSR approach lowers emissions below the CAIR caps, the implementation of lower caps could attain the same emission national reductions as the prerevision NSR rule at about one-third the cost or less. That is due largely to the fact that the retrofit-repower-retire scenario used in the IPM runs to capture the effects of the prerevision NSR tends to be a less-efficient means of achieving national emission reductions than market-based approaches. In the lower emission cap scenario, more low-sulfur coal and natural gas were used and fewer retrofits were made relative to the retrofit-repower-retire scenario. The estimated cost difference between a more traditional regulatory approach, such as NSR, and a market-based approach would be especially great if the application of the first type of approach were based on which plants happen to first be subject to NSR, not on first focusing on the plants that are the most cost-effective to control. Therefore, if lower national emissions of those pollutants are desired, implementation of emission caps lower than those of CAIR is a more cost-effective means of attaining national emission goals than the prerevision NSR rule. In addition, a market-based approach would give sources an incentive to reduce their emissions sooner than a more traditional regulatory approach, such as NSR, thereby reducing emissions more expeditiously. Whether to undertake such reductions is a policy matter beyond the committee's charge or expertise and involves, among other things, a judgment as to the benefit of the reductions compared with their costs.

Because of the limitations in IPM, emissions could not be assessed at the level of the generating unit, and any effective strategy must be designed and implemented to guard against potential pitfalls, such as worsening air quality in a particular local area. It is reasonable to conclude, however, that the implementation of the ERP could lead to some local changes in SO_2 and NO_x emissions (as well as emissions of other power-plant pollutants, which are not covered under CAIR or other cap-and-trade programs), with increases in some locations and decreases in others. The magnitude of those changes and the number of geographic areas affected are unknown. The committee concluded that although IPM can provide some reasonable insight into national emission patterns under alternative scenarios, such insight is on too large a scale for assessment of health benefits and should not be used for such purposes. It is possible that the spatial redistribution of emissions would have some important effects, either locally or in the aggregate. As discussed in Chapter 7, NO_x emission reductions in an urban area can have a very different effect from NO_x emission reductions in a rural area on O_3 concentrations (both in direction, at least close to the source, and in magnitude). In addition, although SO_2 emission reductions will reduce ambient sulfate (SO_4) concentrations in all locations, the amount of SO_4 reduction will vary geographically, and the health effects will be influenced by downwind population patterns, as well as ambient concentration patterns. Thus, even if IPM were able to provide robust national-level emission estimates, the magnitude or direction of health effects would be unclear without additional geographic specificity.

The committee notes the theoretical possibility that the ERP could reduce emissions by increasing the replacement of old higher-emitting equipment with lower-emitting equipment (although not the lowest-emitting equipment that might have been required before the ERP). Under the revised NSR rules, fewer investment projects would require NSR permits, thus reducing the costs of such projects, both in terms of avoiding NSR-permit-related emission controls and potential delays and uncertainties caused by the NSR permitting process. The newer production equipment might be cleaner than the older equipment it replaces and result in some reduction in emissions, without the addition of pollution-control equipment. Therefore, if the revised NSR rules encouraged additional investment in new equipment, the result could be a reduction in emissions at some facilities, if those facilities would have avoided triggering prerevision NSR by delaying investment in process upgrades. Key questions are whether many investment projects that were discouraged by the prerevision rules would proceed under the revised rules, and how much those projects would reduce emissions. However, available empirical data are not sufficient to formally evaluate this effect.

Other Industrial Sectors

Sectors other than electricity-generating facilities are affected not only by the ERP but also by the 2002 rule changes, which have gone into effect in some locations. However, as described in Chapter 2, the 2002 rule changes have been implemented in only some states, and sufficient data are not available to evaluate the effects of the NSR rule changes with any of the committee's preferred analytic approaches. In addition, industry simulation models are not available for sectors other than the electricity-generating sector, and simulating plant-level decision processes and government regulatory decisions with structural and behavioral models is implausible. Therefore, the only basis today to determine the effects of the NSR rule changes on the sectors other than the electricity-generating sector would be to rely on anecdotal evidence or previous relevant case studies. As discussed in more detail below, it is the committee's judgment that such information does not provide an adequate basis for the evaluations required in the committee's charge.

Our evaluations of permitting data and emission inventories can provide some insight into the sectors other than the electricity-generating sector expected to contribute most to emissions and air-quality changes as a result of the NSR rule changes. For example, for NO_x emissions, the cement industry and pulp and paper mills formed a large fraction of recent NO_x permitting activity for modifications and permitted emissions. The geographic clustering of NO_x emissions from those sectors in Texas, Pennsylvania, Georgia, and Michigan—all of which either contain ozone or $PM_{2.5}$ nonattainment areas or are upwind of states that do—indicates that further research into the influence of NSR on those sectors would be warranted. Similar conclusions can be reached for other pollutants, in that substantial permitting activity for modifications was seen in the chemical, cement, and pulp and paper industries for SO_2; chemical and allied products, metal industries, and pulp and paper for PM; and pulp and paper, soybean oil mills, and lumber and wood products for VOCs. Those permitting data are insufficient for formal analysis, both because of missing information and because data are lacking on sites that did not upgrade or modify, but they provide some insight into areas on which to focus for future analyses. Reduced-form econometric analysis could also be applied to emissions data, testing another possible impact of the NSR changes.

LONG-TERM COLLECTION OF DATA AND IMPROVED MODELING TECHNIQUES NEEDED TO CARRY OUT THE RECOMMENDED APPROACHES

Overall, because of a lack of data and the limitations of current models, information is insufficient to quantify with a reasonable degree of certainty the potential effects of the NSR rule changes on emissions, on human health, on energy efficiency, or on other relevant activities at facilities subject to the revised NSR program. For any of the analytic approaches recommended by the committee, additional data collection and improved modeling methods would be warranted to improve the likelihood that the effects of the NSR rule changes could be measured. Equally or more important, the steps recommended by the committee would be valuable for measuring the effects of future regulatory changes regarding air-pollutant emissions. In the case of the NSR rule changes, not only were postimplementation data not available, but sufficient preimplementation data also were not available. Prospective data collection in areas where NSR rules are most likely to have the greatest effect could lead to more-informed policy decisions in the future.

As mentioned throughout our report, there is no central database on NSR permitting activity, and that constituted an important data gap in the committee's deliberations. The RACT-BACT-LAER clearinghouse[5] does not

[5]RACT-BACT-LAER are acronyms for different program requirements under the Clean Air Act. RACT is reasonably available control technology, BACT is best available control tech-

readily distinguish between new sources and modifications, and the availability of the data varies by state. State permit data are generally limited and are often kept in paper form, with no attempt to be compatible with other states' databases, and there is not much information on minor-construction permits. A standardized database program adopted by all states would make analyses of the permit data more feasible. Regardless of the database program used, the information should be collected by the states in a systematic format (same data fields, field layouts, variable definitions, and so on) and should be maintained by the EPA. We recommend that resources be made available so that EPA and other agencies can collect the information consistently in the future. The information could inform future assessments of NSR rule changes and, perhaps more importantly, could provide the foundation for prospective assessments of other future regulatory actions.

In addition, to prepare for a reduced-form econometric analysis, data should be compiled both on when the NSR rule changes became applicable for facilities in different states (these data are readily available) and on perceptions at regulated firms and among regulators regarding the rule changes, which will help identify when (and whether) investment behaviors are likely to shift. Those data should be collected in both attainment and nonattainment areas.

The Census Bureau data needed for facility-level analyses of investment behavior are already being collected. Researchers wishing to do the analyses need to have Census Bureau-approved projects in secure research data centers. Access to the data is expensive, and the analyses are time-consuming, but there is sufficient time to develop a research protocol before the adequate data would be available. These analyses could be important in evaluating NSR and other related regulations.

Bottom-up sectoral models of the electric-power industry, such as IPM, should be refined to account better for the influence of NSR and related regulations on plant-level decision making. Although that clearly is a daunting task, sequential refinements that capture the factors that influence a plant's decision to retrofit or perform maintenance activities would be feasible. With other enhancements in plant-specific information, the model refinements could potentially improve the reliability of regional (or local) emission estimates and could allow for air-quality and health effects to be formally quantified. In addition, the committee recommends that sectoral models be refined to facilitate parametric sensitivity analyses and more formal uncertainty analysis. In particular, periodic expert review of key inputs and components of a model of regulatory importance would allow for a

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nology, and LAER is lowest achievable emission rate. The clearinghouse contains case-specific information on the "best available" air-pollution technologies that have been required to reduce the emission of air pollutants from stationary sources (EPA 2004d).

more informed updating of the model. Such an investment of effort may not be warranted only to understand the effects of the NSR rule changes, but development of a better working model of the effect of regulations on plant-level decision making would help to inform numerous future analyses. In addition, the use of bottom-up sectoral models is impaired because such models do not exist for sectors other than the electricity-generating sector. Steps should be taken to compile the necessary input data to support development of models for other industry sectors, such as petroleum refining, to allow for more-informed future analyses.

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Terms and Abbreviations

ALAPCO:	Association of Local Air Pollution Control Officials
BACT:	best available control technology (This is the level of control required to obtain a PSD permit.)
BART:	best available retrofit technology
Btu:	British thermal unit
CAA:	Clean Air Act, codified at 42 USC § 7401 et. seq.
CAFE:	corporate average fuel economy
CAIR:	Clean Air Interstate Rule
CAMR:	Clean Air Mercury Rule
CASAC:	Clean Air Scientific Advisory Committee
CEM:	continuous emission monitoring
CGE:	computable general equilibrium
CO:	carbon monoxide
Criteria pollutant:	The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants known to be hazardous to human health and the public welfare (for example, damage to forests and degradation of atmospheric visibility). In addition, these pollutants should be ones whose presence in ambient air results from numerous or diverse mobile or stationary sources. EPA has identified and set standards to protect human health and welfare for six pollutants: ozone, carbon monoxide, particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide, lead, and nitrogen oxide. The term criteria pollutants derives from the requirement that EPA must describe the characteristics and potential health and welfare effects of these pollutants. It is on the basis of such criteria that NAAQS are set or revised.

DOE: U.S. Department of Energy
EIA: U.S. Energy Information Administration
EPA: U.S. Environmental Protection Agency, the agency that implements the Clean Air Act.
ERP: equipment replacement provision
ESP: electrostatic precipitator
FCCU: fluid catalytic cracking unit
FGD: flue-gas desulfurization
Greenfield: refers to an emission source that is part of a newly constructed facility at a site where no facility had previously existed
GW: gigawatts
HAP: hazardous air pollutant
HNO_3: nitric acid
HRSG: heat recovery steam generator
H_2S: hydrogen sulfide
IECM: integrated environmental control model
IGCC: integrated gasification combined cycle
IPM: Integrated Planning Model
LAER: lowest achievable emission rate (This is the level of control required to obtain a Part D NSR permit.)
LCA: life-cycle assessment
LNB: low-NO_x burners
MACT: maximum available control technology
MW: megawatts
NAAQS: National Ambient Air Quality Standards (Many of the mechanisms of the Clean Air Act are aimed at attaining and maintaining compliance with these standards.)
NaOH: sodium hydroxide
Na_2S: sodium sulfide
NEI: National Emissions Inventory
NEMS: National Energy Modeling System
NERC: National American Electric Reliability Council
NESHAP: National Emission Standards for Hazardous Air Pollutants
NH_3: ammonia
N_2O: nitrous oxide
N_2O_4: dinitrogen tetroxide
N_2O_5: dinitrogen pentoxide
NO: nitric oxide
NO_2: nitrogen dioxide
NO_3: nitrogen trioxide
NO_x: nitrogen oxides
NO_y: sum of NO_x and other oxidized compounds

NPRA: National Petrochemical and Refiners Association
NRC: National Research Council
NSPS: New Source Performance Standards
NSR: New Source Review (The collective name for the Part D NSR and PSD programs.)
O_3 ozone
ODS: ozone-depleting substance
OTC: Ozone Transport Commission
PAL: plantwide applicability limitation (A PAL limits emissions from a source or facility as a whole.)
Part D NSR: This is the NSR program that applies to sources seeking permits in areas whose air quality violates the NAAQS.
PCP: pollution-control project
PM: particulate matter
$PM_{2.5}$: particles less than 2.5 μm in aerodynamic diameter, called fine particles
PM_{10}: particles less than 10 μm in aerodynamic diameter
ppm: parts per million
PSD: prevention of significant deterioration (This is the NSR program that applies to sources seeking permits in areas whose air quality complies with the NAAQS.)
R&D: research and development
RACT: reasonably available control technology
REMSAD: Regulatory Modeling System for Aerosols and Acid Deposition
RIA: regulatory impact analysis
RMRR: routine maintenance, repair, and replacement
R/R/R: retrofitting flue-gas desulfurization (FGD)—selective catalytic reduction (SCR) systems, repowering, or retiring of a coal-fired electricity-generating facility
SCOT: Shell Claus off-gas treating
SCR: selective catalytic reduction
SIC: Standard Industrial Classification
SIP: state implementation plan (Every state must prepare a plan to show how it will attain and maintain the NAAQS.)
SNCR: selective noncatalytic reduction
SO_2: sulfur dioxide
STAPPA: State and Territorial Air Pollution Program Administrators
TVA: Tennessee Valley Authority
UAM: Urban Airshed Model
VOC: volatile organic compound

APPENDIX A

Biographical Information on Committee

Charles F. Stevens (*Chair*) is a Howard Hughes Medical Institute Investigator and the Vincent J. Coates Professor of Molecular Neurobiology at the Salk Institute for Biological Studies in La Jolla, CA. Previously, he was professor and chair of the Section of Molecular Neurobiology at the Yale University School of Medicine. Dr. Stevens's research centers on mechanisms responsible for synaptic transmission in the central nervous system, using a combination of molecular biological, electrophysiological, anatomical, and theoretical methods. He is a member of the National Academy of Sciences and the American Academy of Arts and Sciences. Dr. Stevens served on a number of NRC committees and as chair of the Committee on Possible Effects of Electromagnetic Fields on Biological Systems. In addition to his publications in the field of neurobiology, he authored a book on the core theories of modern physics. Dr. Stevens serves as an advisor to a telecommunications firm on the possible health effects of cell phone use. He received his M.D. from Yale University School of Medicine and his Ph.D. from Rockefeller University.

Jean M. Andino is an associate professor in the Department of Environmental Engineering Sciences at the University of Florida. She is also affiliated with the university's School of Natural Resources and the Environment and serves as the Technical Leader for Air Revitalization in the NASA-Johnson Space Center-sponsored Environmental Systems Commercial Space Technology Center. Her research focuses on air pollution, specifically the chemical kinetics and mechanisms pertinent to air pollutant formation and control. From 1997 to 2002, Dr. Andino was a National Science Foundation CAREER award recipient. She earned her Ph.D. in chemical engineering from the California Institute of Technology.

Lyle R. Chinkin is the senior vice president for Emissions, Policy, and Geographic Information Systems Services at Sonoma Technology, Inc. (STI). He also serves as STI's corporate general manager. Those business areas encompass the preparation and assessment of stationary- and mobile-source emission inventories for use in air-quality analyses and control strategy development. Mr. Chinkin has expertise in emission inventory preparation and assessment and air-quality analyses. He has performed numerous emission-inventory and air-quality studies primarily for government agencies. He also has directed analyses for industrial associations. His work involves emission inventory field measurements, surveys, development, improvement, preparation, and evaluation. Mr. Chinkin earned an M.S. in atmospheric science from the University of California, Davis.

Herek L. Clack is an assistant professor of mechanical and aerospace engineering at the Illinois Institute of Technology in Chicago. His research interests include transport processes within multiphase flows, and design and development of advanced thermofluid processes with application toward combustion and combustion emissions. Currently, his primary research involves developing methods to control mercury emissions from coal-fired electric power plants. In January 2004, Dr. Clack was awarded a National Science Foundation Faculty Early Development CAREER award. He received his Ph.D. in mechanical engineering from the University of California, Berkeley.

John C. Crittenden is the Richard Snell Presidential Chair in the Department of Civil and Environmental Engineering at the Arizona State University (ASU). His research expertise includes sustainability, pollution prevention, physical-chemical treatment processes in air and wastewater, and modeling of fixed-bed reactors and adsorbers. Dr. Crittenden is the codirector of the Sustainable Technologies Program at ASU and directed the National Center for Clean and Industrial and Treatment Technologies (CenCITT) for 10 years. CenCITT conducted research on environmentally responsible manufacturing and involved 60 faculty from 16 academic units and over 200 graduate students. Dr. Crittenden is a member of the National Academy of Engineering. He is an associate editor of the journal *Environmental Science and Technology*. Dr. Crittenden received a Ph.D. in civil and environmental engineering from the University of Michigan.

H. Christopher Frey is a professor in the Department of Civil, Construction, and Environmental Engineering at the North Carolina State University. Dr. Frey's research is in the areas of environmental control, energy utilization, and modeling methods applicable to exposure assessment. He is involved in a number of different projects, including assessment of advanced technology for controlling sulfur dioxide and nitrogen oxide emissions from coal-fired power plants, advanced electric-power generation and end-use technologies for transfer to developing countries, and optimal design capability for coal gasification systems. Dr. Frey's research and consulting work has been funded by a number of sources, including EPA, DOE, NSF, consulting firms, industry, universities, and nonprofit organizations. Dr. Frey has contributed to assessments and guidance documents particularly pertaining to uncertainties in emission characterization, exposure assessment, and risk assessment for organizations such as the Intergovernmental Panel on Climate Change (IPCC), NARSTO, and the World Health Organization and Food and Agriculture Organization (WHO/FAO). He serves on EPA's Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) Scientific Advisory Panel and is president of the Society for Risk Analysis. He earned a Ph.D. in engineering and public policy from Carnegie Mellon University.

Wayne Gray is a professor of economics in the Department of Economics at Clark University. He also is a research associate at the National Bureau of Economic Research (NBER), a private, nonprofit research organization. As part of his duties at NBER, Dr. Gray is the director of the Boston Census Research Data Center, which operates as a joint partnership between NBER and the U.S. Census Bureau. Dr. Gray's research focuses on the effectiveness and economic impact of government regulation, including impacts of EPA regulations on productivity and investment decisions at the industrial plant level, especially within the steel and paper industries. He is a member of the Advisory Council for Clean Air Compliance Analysis of EPA's Science Advisory Board. Dr. Gray received a Ph.D. in economics from Harvard University.

Benjamin F. Hobbs is a professor in the Department of Geography and Environmental Engineering and the Department of Applied Mathematics and Statistics (joint) at Johns Hopkins University. Dr. Hobbs's research activities involve the development and application of systems analysis and economic methods to analyze energy, water, and environmental problems. He currently has research projects investigating regulatory and economic influences on the electric-power sector. Dr. Hobbs has received funding for research and consulting from various sources including EPA, U.S. Geological Survey, National Science Foundation, and industry, such as the Baltimore Gas & Electric Corporation and the Electric Power Research Institute. He is a member of the California Independent System Operator Market Surveillance Committee. His Ph.D. is in environmental systems engineering from Cornell University.

Jonathan I. Levy is an associate professor of environmental health and risk assessment in the Departments of Environmental Health and Health Policy and Management at the Harvard School of Public Health. Dr. Levy's research centers on developing models to quantitatively assess the environmental and health impacts of air pollution on local, regional, and national scales, the focus being on urban environments. This work involves the evaluation of exposure using a combination of atmospheric dispersion modeling, predictive statistical models, and field measurements. Dr. Levy has published several papers that model the health impacts of emissions from power plants and has evaluated the effects of particulate matter and ozone on premature mortality. In 2005, he was awarded the Walter A. Rosenblith New Investigator Award from the Health Effects Institute for research modeling indoor and outdoor concentrations of traffic-related air pollution. He earned a Sc.D. in environmental science and risk management from the Harvard School of Public Health.

Thomas A. Louis is professor of biostatistics at the Johns Hopkins Bloomberg School of Public Health. He earned a Ph.D. in mathematical statistics from Columbia University. His research interests include risk assessment, environmental health and public policy, and development of related statistical approaches. Current applications include assessing the health effects of airborne particulate matter, assessing the cardiopulmonary complications of AIDS therapy, and clinical quality improvement. He is a fellow of the American Statistical Association and of the American Association for the Advancement of Science. He serves on the Health Review Committee of the Health Effects Institute and on the EPA's Science Advisory Board Drinking Water Committee. Dr. Louis's previous National Academies service includes the Committee on National Statistics, the Board of the Institute of Medicine (IOM) Medical Follow-up Agency, the IOM Panel to Assess the Health Consequences of Service in the Persian Gulf War, the Panel on Estimates of Poverty for Small Geographic Areas, and the Committee on the Use of Third Party Toxicity Research with Human Research Participants. He also chaired the Panel on Formula Allocation of Federal and State Program Funds.

Joe L. Mauderly is vice president of the Lovelace Respiratory Research Institute; president of its subsidiary, the Lovelace Biomedical and Environmental Research Institute; director of one of its research programs, the National Environmental Respiratory Center; and former director of the Inhalation Toxicology Research Institute. Dr. Mauderly received his D.V.M. degree from Kansas State University, and after brief periods in clinical practice and the U.S. Air force, specialized in research on comparative respiratory physiology, comparative pulmonary responses to inhaled toxicants, and the adverse effects of materials inhaled in the workplace and environment. During the past decade, his research has focused on the health effects of complex mixtures of air contaminants, including engine emissions. He is an adjunct professor of medicine at the University of New Mexico and on the editorial board of *Inhalation Toxicology*. He is a member of the Particulate Matter Panel of EPA's Clean Air Scientific Advisory Committee (CASAC) and member or chairman of several research center advisory committees.

His past appointments include chairman of the CASAC of the EPA Science Advisory Board, chair and member of several National Research Council (NRC) committees, chairman of the Environmental and Occupational Health Assembly of the American Thoracic Society, president of the Inhalation Specialty Section of the Society of Toxicology, member of the Research Committee of the Health Effects Institute, chairman of the Air Pollution Health Advisory Committee of the Electric Power Research Institute, associate editor of *Fundamental and Applied Toxicology*, and editorial board member of *Experimental Lung Research*.

Craig N. Oren is a professor at the Rutgers School of Law. Mr. Oren has written extensively on the Clean Air Act, including the New Source Review provisions of the Act. He received his A.B. and J.D. degrees from the University of California, Berkeley. From 1979 to 1983, Mr. Oren served as assistant counsel to the Subcommittee on Health and the Environment of the House Energy and Commerce Committee. He served on the Committee on Risk Assessment of Hazardous Air Pollutants and the Committee on Haze in National Parks and Wilderness Areas.

Karen L. Palmer is a senior fellow at Resources for the Future in the Quality of the Environment Division. She served as an economist with the Federal Energy Regulatory Commission, Office of Economic Policy. Her research interests include the environmental and economic consequences of electricity restructuring and of new environmental policy proposals targeted at the electricity sector; the regulation of solid waste and recycling; and the cost-effectiveness of environmental regulation. Dr. Palmer also is studying the costs and environmental benefits of the product stewardship movement, which among other things encourages industry to play a more active role in dealing with the environmental consequences of products at the end of their useful lives. She received a Ph.D. in economics from Boston College.

Lynn M. Russell is a professor in the Center for Atmospheric Sciences, Scripps Institution of Oceanography, University of California, San Diego. Her research is in the area of aerosol particle chemistry, including the behavior of particles under pristine and anthropogenically influenced conditions. Her research interests span experimental and modeling approaches to aerosol evolution in the atmosphere, incorporating chemical and physical mechanisms in aerosol-cloud interactions, organic aerosols, and their radiative effects. She has served on several NRC committees, including the Panel on Aerosol Radiative Forcing and Climate Change, the Committee to Review NARSTO's Scientific Assessment of Airborne Particulate Matter, and the Panel on Atmospheric Effects of Aviation. She holds a Ph.D. in chemical engineering from the California Institute of Technology.

Mitchell J. Small is the H. John Heinz III Professor of Environmental Engineering in the Departments of Civil and Environmental Engineering and Engineering and Public Policy at Carnegie Mellon University. He earned his Ph.D. in environmental and water resources engineering from the University of Michigan. Dr. Small's research focuses on mathematical modeling of environmental quality, including statistical methods and uncertainty analysis, human exposure modeling, indoor air pollution, human risk perception and decision making, and integrated assessment models for acid deposition and global climate change. Dr. Small has served on EPA's Office of Research and Development's Board of Scientific Counselors and is currently a member of EPA's Science Advisory Board. He has served on several NRC committees, including the Committee on Remediation Priorities for Hazardous Waste Sites and the Committee on Environmental Remediation at Naval Facilities. Dr. Small is an associate editor for the journal *Environmental Science & Technology*.

Ira B. Tager is professor of epidemiology in the Division of Public Health, Biology, and Epidemiology at the University of California, Berkeley, and is codirector and principal investigator for the Center for Family and Community Health. He holds an M.D. from the University of Rochester School of Medicine and an M.P.H from the Harvard School of Public Health. Dr. Tager's research interests include the development of exposure assessment instruments for studies of health effects of chronic ambient ozone exposure in childhood and adolescence, the effects of ozone exposure on pulmonary function, and the effects of oxidant and particulate air pollution on cardiorespiratory morbidity and mortality as well as morbidity from asthma in children. Dr. Tager was a member of the NRC Committee on Air Quality in Passenger Cabins of Commercial Aircraft. He currently serves as a member of the Research Committee for the Health Effects Institute.

John G. Watson is a research professor in the Division of Atmospheric Sciences at the Desert Research Institute in Reno, Nevada. His research includes the development and evaluation of measurement processes, receptor models for source apportionment, and the effects of measurement uncertainty on model results. Dr. Watson is the primary author of a chemical mass balance receptor model and its application and validation protocol. Dr. Watson is currently principal investigator for the California regional particulate and air quality study, the Fresno Supersite, the southern Nevada air quality study, and for a Department of Defense program to quantify emissions from nonroad diesel engines. He recently completed the 2002 Air and Waste Management Association's critical review of *Visibility: Science and Regulation* that examined evolution and scientific justification for EPA's Regional Haze Rule. He earned a Ph.D. in environmental science from the Oregon Graduate Institute.

APPENDIX B

Congressional Mandate[1]

As soon as practicable after the date of enactment of this Act, the Administrator of the Environmental Protection Agency shall enter into a cooperative agreement with the National Academy of Sciences to evaluate the impact of the final rule relating to prevention of significant deterioration and nonattainment new source review, published at 67 Fed. Reg. 80186 (December 31, 2002). The study shall include

1) increases or decreases in emissions of pollutants regulated under the New Source Review program;
2) impacts on human health;
3) pollution control and prevention technologies installed after the effective date of the rule at facilities covered under the rulemaking;
4) increases or decreases in efficiency of operations, including energy efficiency, at covered facilities; and
5) other relevant data.

The National Academy of Sciences shall submit an interim report to Congress no later than March 3, 2004, and shall submit a final report on implementation of the rules.

In 2004, following EPA's promulgation of the equipment replacement rule, published in 68 Fed. Reg. 61248 (October 27, 2003), Congress amended the provision shown above to include an identical study of the equipment replacement rule. The National Academy of Sciences was required to issue an interim report by January 1, 2005. This report responds to that charge.

[1]Conference Report on H.J. RES. 2, Consolidated Appropriations Resolution, 2003.

APPENDIX C

Statement of Task

An NRC committee will evaluate potential air quality, public health, and other impacts of EPA's final rules of December 31, 2002, and October 27, 2003, relating to "prevention of significant deterioration" in areas currently meeting air quality standards and "new source review" in areas that do not currently meet air quality standards. The programs are collectively referred to as NSR. Taking into account the relatively short time that will have elapsed since the promulgation of the rule and the economic conditions that have prevailed in the interim, the committee will consider the data and methods necessary to assess specific effects of the NSR rules expected to occur in the coming years. To the extent possible, the committee will utilize such approaches to estimate and evaluate the following:

- Resulting increases or decreases in emissions of pollutants regulated under the NSR program;
- Resulting impacts on human health;
- Pollution control and prevention technologies to be installed after the effective dates of the rules at facilities covered under the NSR rulemaking;
- Increases or decreases in efficiency of facility operations, including energy efficiency, at new and existing facilities covered by the NSR rule;
- Other relevant data; and
- The amount of uncertainty associated with estimates of the effects mentioned above.

Having reviewed and evaluated the available data, the committee would be expected to identify and recommend additional data collection that would be necessary in the future years going forward to assess impacts.

In addition to a final report, the committee will provide an interim report containing all conclusions and recommendations the committee determines to be feasible and appropriate at that stage in its study.

SPONSOR: U.S. Environmental Protection Agency.

APPENDIX D

Permit and Permitted Emission Data

The data that the U.S. Environmental Protection Agency (EPA) has provided to the committee in Table D-1 are preliminary, unpublished, not subjected to review, and not distributed outside EPA. These data are based on information collected internally by EPA from its regional offices, which was obtained from state and local permitting authorities. The data were summarized by EPA for the committee in terms of the New Source Review (NSR) permitted emissions (in tons) by the two-digit Standard Industrial Classification (SIC) code and by the number of permits. Permits were categorized as "greenfield," new at existing sources, and modifications. The main focus here is on modifications. These data do not include information on facilities that made modifications but did not obtain permits via the NSR programs. Although the information presented in the table is sorted by pollutant, it is possible for a modification to involve more than one pollutant.

TABLE D-1 Summary of Estimated Number of Permits and Permitted Emissions Under New Source Review for Greenfield[a] Facilities, New Facilities at Existing Locations, and Modifications, During 1997-1999

		Number of Permits[b]			Number of Permits by SIC	NSR Permitted Emissions (tons)		
SIC	SIC Type	Greenfield	New at Existing Location	Modifications		Greenfield	New at Existing Location	Modifications
CO								
10	Metal mining	0	2	0	2	—	1,831	—
12	Coal mining	0	0	2	2	—	—	3,696
13	Oil and gas extraction	3	3	3	9	3,047	1,286	253
14	Nonmetallic minerals except fuels	0	4	0	4	—	2,020	—
20	Food and kindred products	1	7	6[b]	14	135	7,029	16,366
24	Lumber and wood products	0	3	6	9	0	797	2,953
26	Paper and allied products	1	10	7[b]	18	215	18,691	24,878
27	Printing and publishing	1	0	0	1	15	—	—
28	Chemicals and allied products	0	12[b]	5	17	—	1,896	7,699
29	Petroleum and coal products	0	4	5	9	—	1,070	2,033
32	Stone, clay, and glass products	3	16	6	25	15,198	19,456	18,001
33	Primary metal industries	2	11	17	30	3,880	16,987	17,084
49	Electric, gas, and sanitary services	114	96[b]	38[b]	248	88,743	51,365	15,890

continues

TABLE D-1 Continued

SIC	SIC Type	Number of Permits[b] Greenfield	New at Existing Location	Modifications	Number of Permits by SIC	NSR Permitted Emissions (tons) Greenfield	New at Existing Location	Modifications
51	Wholesale trade—nondurable goods	0	1	0	1	—	55	—
82	Educational services	0	1	0	1	—	170	—
96	National security and intl. affairs	0	1	0	1	—	NA	—
Total tons		125	171	95	391	111,233	122,653	108,853
PM(10)								
10	Metal mining	0	1	0	1	0	35	0
12	Coal mining	0	0	3	3	0	0	505
13	Oil and gas extraction	2	2	0	4	423	45	0
14	Nonmetallic minerals except fuels	0	4	0	4	0	314	0
20	Food and kindred products	1	12[b]	8	21	41	2,171	2,204
24	Lumber and wood products	1	7	11	19	9	834	1,101
25	Furniture and fixtures	0	1	0	1	0	11	0
26	Paper and allied products	1	12	10[b]	24	46	2,121	3,047
27	Printing and publishing	1	0	0	1	14	0	0
28	Chemicals and allied products	1	18	12[b]	31	14	1,002	3,402
29	Petroleum and coal products	0	4	7	11	0	264	454
30	Rubber and misc. plastics products	0	0	1	1	0	0	6

32	Stone, clay, and glass products	3	23	8	34	1,278	4,899	2,569
33	Primary metal industries	2	16	24[b]	42	352	1,493	1,437
34	Fabricated metal products	0	0	1	1	0	0	7
37	Transportation equipment	0	0	2	2	0	0	17
49	Electric, gas, and sanitary services	95	67[b]	30	192	17,548	9,659	2,580
51	Educational services	0	1	0	1	0	77	0
97	National security and intl. affairs	0	0	1	1	2	0	18
Total tons		107	168	118	393	19,727	22,925	17,347
NO_x								
10	Metal mining	0	2	1	3	0	26,179	4,765
12	Coal mining	0	2	0	2	0	0	1,506
13	Oil and gas extraction	3	3	3	9	5,959	3,861	60
14	Nonmetallic minerals except fuels	0	4	0	4	0	1,136	0
20	Food and kindred products	1	9	7[b]	14	75	6,706	2,028
24	Lumber and wood products	0	3	6	9	0	510	1,168
26	Paper and allied products	1	12	8	20	129	7,398	
27	Printing and publishing	0	0	1	1	90	0	0
28	Chemicals and allied products	1	17	7	26	186	3,841	1,776
29	Petroleum and coal products	0	7	6	13	0	2,381	2,989

continues

TABLE D-1 Continued

SIC	SIC Type	Number of Permits[b]			Number of Permits by SIC	NSR Permitted Emissions (tons)		
		Greenfield	New at Existing Location	Modifications		Greenfield	New at Existing Location	Modifications
30	Rubber and misc. plastics products	0	1	0	1	0	33	0
32	Stone, clay, and glass products	3	18	8	31	9,388	27,842	20,479
33	Primary metal industries	1	13	13[b]	26	406	5,031	2,842
36	Electronic and electric equipment	0	1	0	1	0	18	0
37	Transportation equipment	1	2	0	3	2	1,080	0
46	Pipelines except natural gas	1	0	0	1	353	0	0
49	Electric, gas, and sanitary services	125	97[b]	46	299	91,280	28,496	26,228
51	Wholesale trade—nondurable goods	0	1	0	1	0	434	0
82	Educational services	0	1	0	1	0	88	0
97	National security and intl. affairs	0	0	1	1	0	0	650
Total (tons)		137	193	107	437	107,868	115,034	74,512
SO_2								
10	Metal mining	0	1	0	1	0	37	0
12	Coal mining	0	0	2	2	0	0	2,221
13	Oil and gas extraction	3	3	0	6	2,232	1,294	0
14	Nonmetallic minerals except fuels	0	2	0	2	0	640	0
20	Food and kindred products	2	8	6	16	80	26,272	5,494

24	Lumber and wood products	0	0	1	1	0	0	20
26	Paper and allied products	0	9	9	18	0	3,978	12,634
27	Printing and publishing	1	0	0	1	5	0	0

[a]Greenfield refers to a site where a new facility is built and no facility had existed previously.
[b]Numbers do not sum to total because some permits had both modifications and new units.

SOURCE: EPA, unpublished data, August 2004.

APPENDIX E

Repair and Replacement Activities in Selected Industries

A summary of common repair and replacement activities for specific parts of a typical coal-fired power plant is given in Table E-1. The table does not attempt to summarize less frequent major replacements at a plant, such as repowering with a new furnace using an existing steam cycle or replacing major components (for example, a turbine generator) with an entirely new system.

Table E-2 presents the aggregated responses to a National Petrochemical and Refiners Association member survey, initiated in response to an information request from the committee. Sixty-four petroleum refineries responded to the survey, constituting half (8,808,122 barrels/day) of the total U.S. petroleum-refining capacity (16,894,314 barrels/day) (EIA 2004c). Table E-2 presents about 60 activities that typically are undertaken as repair and replacement at petroleum refineries. Each activity is listed with an estimate of how frequently it occurs and its cost. The cost of each activity is presented as a percentage of the total replacement cost of the major process unit with which the activity is associated. For example, replacing or repairing the fluidized catalytic cracking unit (FCCU) regenerator cyclones is estimated to occur at intervals of 3-5 years or longer. The cost of this activity is estimated to be up to 10% of the replacement cost of the FCCU. Because not all refineries are of the same size and configuration, there are likely to be variations in the replacement-cost percentages. The results presented in this survey, although not exhaustive, illustrate the diverse nature of repair and replacement activities typically undertaken at petroleum refineries.

Table E-3 lists repair and replacement and other activities peculiar to Kraft mills that are periodically undertaken. Both the structure of Table E-3 and its contents were provided by representatives of International Paper, Inc., in response to an information request from the committee. Table E-3 lists about 90 repair and replacement activities that are periodically undertaken in a Kraft mill. For each activity, the table provides an estimate of how frequently the activity occurs, an estimate of how likely the activity is to occur within the specified interval, and the relative cost of the activity. The relative cost of the activity is presented as a percentage of the replacement cost of the major process component with which the activity is associated. For example, repairing or replacing the boiler safety relief valves is estimated with near certainty to be an annual activity at a Kraft mill, with an estimated cost that is less than 5% of the replacement cost of the entire boiler. Although the list of activities in Table E-3 is not certified as exhaustive, it illustrates a variety of repair and replacement activities that may be undertaken in pulp and paper manufacturing facilities.

The repair and replacement activities presented here are expected to have different frequencies and costs among industrial sectors, production facilities, and types of process units because many factors, such as equipment design and operating conditions, affect their frequency and cost (R. Bessette, Council of Industrial Boiler Owners, November 10, 2004, letter to committee).

TABLE E-1 Summary of Common Repair and Replacement Activities, Frequencies, and Cost for Coal-Fired Electricity-Generating Facilities

Category	Description	Repair or Replacement Needs
Boiler-tube assemblies	Rows or bundles of heat-exchanger tubes	Wear and periodic failure attributable to erosion, corrosion, and temperature/pressure-related stresses, leading to such outcomes as leaks, forced outages, loss of reliability, and potential for substantial boiler failure
Air heaters	Heat exchangers that transfer heat from flue gas to incoming combustion air	Exposure to ash, condensate, and acid gases in flue-gas path can lead to plugging, corrosion, and erosion, leading to loss of heat-transfer efficiency. Leakages or pluggage in the air preheater can reduce effective capacity at the plant
Fans	Forced-draft fans push combustion air into the furnace; induced-draft fans pull flue gas from the furnace. A balanced-draft system has both. Other typical fans include primary air fans for pneumatic transport of pulverized coal and flue-gas recirculation fans for NO_x control	Erosion and cyclic fatigue; fans exposed to flue gases often subject to higher temperatures as well as erosive ash and corrosive acid gases. Reduced effectiveness of fan reduces plant output; failure leads to shutdown
Mills/feeders	System for feeding and pulverizing coal into a fine powder	Abrasion due to hard minerals in coal, and erosion where solids/powder strikes interior surfaces, including deterioration of rollers, tables, balls, classifiers, bearings, seals, motors, belts, flow-control devices, and piping
Turbines and generators	Steam turbines are composed of a shell, blades, nozzles, diaphragms, and rotors. Generators are composed of rotors and stators, including windings and insulation	Turbine blades experience wear due to impurities in steam, requiring replacement of blades (usually with better designed shapes and more recently available alloys). Generator insulation can deteriorate because of exposure to heat or contaminants
Condensers	Typically, a shell and tube heat exchanger in which river water flows on the tube side and low-temperature steam and low pressure (at a vacuum compared with ambient) are on the shell side	Flow on either side can lead to erosion. Impurities in steam or water can lead to corrosion. Biologic fouling on the water side is also possible. Partial or full pluggage of tubes reduces heat transfer, and tube failure leads to contamination of the steam cycle

Frequency	Cost
Considered to be common; entire tube assemblies replaced at nearly every boiler, as early as 5 years after the beginning of commercial operation	Up to $40/kW to replace tube assemblies on a large boiler and potentially more on a smaller boiler
Replacement in over 80% of units of basket layers and tubes. Seal replacement is also common	Up to $6/kW on large boilers, higher costs per kW on smaller boilers
Fans have been substantially replaced in over 70% of units	Replacement of a large fan can cost up to $20/kW. Retrofitting a balanced-draft system in place of a forced-draft system can cost $70/kW
Pulverizer mills have been replaced or substantially repaired in over 50% of units	Replacing wear parts in a pulverizer mill can cost $2/kW and mill replacement can cost up to $5/kW
Turbine blades or rotors have been replaced in more than 90% of units	Turbine blade and rotor replacement can cost up to $20/kW. Replacement of the shell of the turbine can cost up to $60/kW
More than 60% of units have replaced condenser tubes	Tube bundle replacement can cost up to $10/kW

continues

TABLE E-1 Continued

Category	Description	Repair or Replacement Needs
Control systems	Control and monitoring of boiler, turbine, and balance of plant management	Control systems affect combustion efficiency and other operations of the plant. When systems fail and require replacement, replacement parts for the original design may no longer be available
Coal and ash handling	Unloading, storage, and conveying coal. Key subsystems include bulldozers (to manage the coal pile), conveyor belts, and bunkers (or silos)	Wear of conveyor belts, motors, and other equipment; corrosion
Feedwater heaters	Heat exchangers, treatment system, and pumps to deliver, heat, and process water from the condenser to the economizer	Leaking tubes lead to reduced efficiency. Plugged tubes lead to loss of capacity
Sootblowers and water lances	System for delivery of steam or compressor air to remove soot, ash, and slag from surfaces of such equipment as heat exchanger tubes	Deterioration of sootblowers reduces effectiveness, which leads to less-efficient cleaning of surfaces. The latter can lead to losses or damage. For example, uncontrolled buildup of slag on boiler surfaces can lead to failure if large amounts of slag fall and damage boiler internals
Burners	Burner systems include tubes and, in some cases, annuli through which pulverized coal and staged air are introduced. Dampers, vanes, nozzles, windbox, flame scanners, and lighters are other typical components	High temperatures, ash, and corrosive gases can lead to corrosion, erosion, and temperature-related stresses
Motors	Motors are used throughout a plant to drive pumps, belts, pulverizers, and other equipment. Motors can vary greatly in size	Motor failures typically attributable to failure of insulation, which causes overheating and potential shortouts
Electric equipment	Equipment used to convert and transmit electricity in a form useful for internal plant end uses, such as motors, fans, and lighting	Exposure to coal dust, temperatures in the plant, and other aspects of the plant environment can lead to shorts and overloads
Pumps	Pumps are used throughout the plant for feedwater, cooling water, and slurries (such as ash sluice). Pumps can be exposed to corrosive materials, erosive materials, and extremes of temperature and pressure	Failure typically due to corrosion, erosion, and other demanding service conditions (such as high temperature and pressure)

Frequency	Cost
Replacement of pneumatic controls with solid-state, computerized, or automated controls has occurred in “most” units	Replacement projects can cost up to $10/kW on larger units and $40/kW on smaller units
Replacement of such components as conveyor belts, motors, and barge and rail unloaders is “common”	Replacement of key components of coal handling can cost up to $4/kW. Replacement of key components of ash-handling systems can cost up to $14/kW
More than 80% of units have replaced feedwater heaters or major tube bundles therein	Replacement of a feedwater heater can cost up to $5/kW
Sootblowers have been replaced at “most” units	Replacement projects can cost up to $9/kW
Replacements have occurred “one or more times at most units”	Replacements can cost up to $30/kW
Rewind or replacement of motors is “common”	Replacements can cost up to $5/kW per motor
Replacement of switchgear and other equipment is “very common”	Replacement projects cost up to $9/kW
Nearly 100% of units have overhauled or replaced boiler feedpumps	Replacement projects can cost $10/kW

continues

TABLE E-1 Continued

Category	Description	Repair or Replacement Needs
Piping/ ducts/ expansion joints	Pipes carry fluids or slurries. Ducts carry gases. Expansion joints are flexible connections between pipes or ducts	Leaks can occur because of high-pressure, high-temperature environments or because of erosion or corrosion. Expansion joints can crack or separate
Air compressors	Compressed air is used for pneumatic drives, system controls, some sootblowers, and some power tools	Moving parts are subject to typical wear. Reduced effectiveness of the compressor or failure can lead to reduced effectiveness or failure of other components (such as sootblowers and surfaces not adequately cleaned by failed sootblowers)

SOURCE: ERCC 2002. Reprinted with permission; copyright 2002.

Frequency	Cost
Replacements of pipes, ducts, and expansion joints is "common"	Repair and replacement can cost up to $23/kW
Replacement is a typical choice, but frequency is not reported	Replacement projects can cost up to $2/kW

TABLE E-2 Projected Repair and Replacement Frequencies and Relative Costs in Petroleum-Refinery Industry

		Estimated Frequency (years)				Replacement Cost (% per unit)			
Activity	Unit	1	3-5	5	>5	<5	5-10	10-20	>20
Pumps									
Replace pump seals	All	X	X	X		X	X		
Repair pumps	All	X				X			
Replace pumps	All				X	X	X		X
Valves									
Replace valve packing	All	X	X	X	X	X			
Replace valves	All				X	X			
Catalysts									
Regenerate catalysts	Reformer	X				X			
Replace catalysts	Hydrotreaters		X			X			
Replace catalysts	SRU			X		X			
Replace catalysts	not specific	X	X	X		X	X		
Column reactors									
Repair or replace trays and hardware	All		X				X		
Repair or replace reactor internals	All		X			X			
Replace weld overlays inside columns, vessels, and reactors	All				X	X	X		
Pressure safeties									
Repair, replace, test PSVs	All		X			X			
Exchangers									
Repair or replace exchanger	All				X				X
Repair or replace bundle	All		X				X	X	
Clean tubes	All		X			X			
Crude unit									
Crude unit turnaround	Crude		X	X			X		
Fluidized catalytic cracking unit (FCCU)									
FCCU turnaround	FCCU		X	X			X	X	X
FCCU turnaround with cyclone replacement	FCCU				X				X
Replace or repair spent catalyst deflectors in an FCCU	FCCU		X		X	X			

TABLE E-2 Continued

		Estimated Frequency (years)				Replacement Cost (% per unit)			
Activity	Unit	1	3-5	5	>5	<5	5-10	10-20	>20
Fluidized catalytic cracking unit (FCCU) ***continued***									
Replace or repair slide valves (orifice plates and tongues)	FCCU		X			X			
Replace or repair spent catalyst slide-valve actuators	FCCU		X	X	X	X	X		
Replace or repair FCCU regenerator cyclones	FCCU		X		X	X	X		
Replace or repair FCCU reactor cyclones	FCCU		X		X	X	X		
Replace or repair fractionation-tower internals	FCCU		X		X	X		X	
Repair fractionation-tower internals	FCCU		X	X	X	X		X	
Replace or repair wet-gas compressor	FCCU		X		X	X			
Turnaround	Reformer		X					X	
Alkylation unit									
Turnaround	Alkylation		X				X		
Hydrocracker									
Turnaround	Hydrocracker		X				X		
MTBE (methyl tert-butyl ether) unit									
Turnaround	MTBE		X					X	
Diesel desulfurization									
Turnaround with catalyst change	Hydrotreatment unit	X				X			
Coker									
Coke drum replacement	Coker				X			X	X
Crude/coker turnaround	Coker			X		X			
Sulfur plant									
SRU thermal-reactor repair	SRU		X			X			
SRU thermal-reactor replacement	SRU				X			X	
Turnaround	SRU		X					X	

continues

TABLE E-2 Continued

Activity	Unit	Estimated Frequency (years)				Replacement Cost (% per unit)			
		1	3-5	5	>5	<5	5-10	10-20	>20
Flare									
Flare-tip replacement	Flare				X		X		
Flare knockout drum replacement	Flare				X				X
Replace flare	Flare				X			X	
Piping									
Repair piping recorrosion	All		X		X	X	X		
Replace piping recorrosion	All		X	X	X	X		X	
Heaters/boilers									
Replace or repair heater tubes	All			X	X	X	X		
Replace or repair boiler tubes	Boilers			X	X	X	X	X	
Replace burners	All				X	X	X		
Steam turbine									
Steam turbine repairs	Turbine		X			X			
Steam turbine replacement	Turbine				X		X		
Storage tanks									
Repair storage tanks	Tank farm			X	X	X		X	
Replace storage tanks	Tank farm				X	X		X	
Replace floating roofs in tanks	Tank farm				X	X			X
Replace floor in tanks	Tank farm				X			X	
Wastewater systems									
General maintenance	Wastewater	X				X			
Metallurgical changes									
Metallurgic changes to accommodate feedstock quality changes					X				X
Instrumentation									
Replace CEMS					X			X	
Repair CEMS				X				X	
General instrumentation		X				X			
Replace instrumentation					X			X	

TABLE E-2 Continued

		Estimated Frequency (years)				Replacement Cost (% per unit)			
Activity	Unit	1	3-5	5	>5	<5	5-10	10-20	>20
Electric substations									
Replace substations					X			X	
Repair substations			X			X			
Replace transmission lines					X			X	

ABBREVIATIONS: CEMS = continuous emission monitoring system; SRU = sulfur recovery unit.
SOURCE: National Petrochemical and Refiners Association, unpublished material, 2004.

TABLE E-3 Pulp and Paper Industry: Repair and Replacement Activities

		Estimated Frequency				Percent Replacement Cost		
Activity	Category[a]	1 year	5 years	10 years	20 years	<5	5-10	10-20
Boiler used to generate power								
Repair superheater tie lugs	4	X	X			X		
Repair superheater steam-cooled spacers	4		X	X		X		
Replace superheater loops	4		X	X		X		
Replace superheater assemblies	4,7			X	X		X	
Replace desuperheater liner assembly	4				X	X		
Replace economizer assemblies	4,7				X		X	
Replace generating bank tubes	4,6,7			X	X		X	
Replace lower-wall tube sections	4,6,7			X	X	X		
Replace lower-wall tube panels	4,6,7				X	X		
Replace lower furnace	4,6,7				X			X
Repair tubular air heaters	4,5	X	X	X	X	X		
Replace tubular air heaters	4			X	X	X		
Repair refractory	4	X				X		
Repair/replace cyclone burners	4,6	X	X				X	
Clean and scaffold fire side	1,2,4	X				X		
Auxiliary equipment for power boiler								
Repair/rebuild coal pulverizers	4	X				X		
Repair/rebuild traveling grates	4	X		X		X		
Repair/rebuild ash-handling system	4	X	X	X		X		
Repair/rebuild coal-feeder systems	4	X				X		
Repair/rebuild boiler safety relief valves	1, 2	X				X		
Remove, calibrate, and simulate boiler protective interlock devices	1, 2	X				X		

TABLE E-3 Continued

Activity	Category[a]	Estimated Frequency 1 year	5 years	10 years	20 years	Percent Replacement Cost <5	5-10	10-20
Auxiliary equipment for power boiler *continued*								
Replace, calibrate, and simulate boiler protective interlock devices	1, 3, 4			X		X		
Repair/rebuild burner assemblies	4	X				X		
Repair/rebuild sootblowers	4	X				X		
Repair/rebuild dust collectors	4	X				X		
Repair/rebuild precipitators	4	X				X		
Repair/rebuild turbine drives	1, 2, 4		X			X		
Repair/rebuild FDand ID fans	4		X			X		
Upgrade safety systems to revised standards	1, 2, 3			X		X		
Replace unsupported control hardware	3, 4			X	X		X	
Inspect/repair stack	2, 4		X			X		
Repair/rebuild ducts and flues	4		X	X		X		
Building structural repair	4			X	X	X		
Chemical recovery furnace								
Replace smelt spout tube openings	1, 2, 3, 4, 5		X	X		X		
Replace lower-wall tube sections	1, 2, 3, 4		X	X		X		
Replace lower-wall tube panels	1, 2, 3, 4			X	X	X		
Replace lower furnace	1, 2, 3, 4			X	X		X	
Repair superheater tie lugs	1, 2, 4	X	X			X		
Repair superheater steam-cooled spacers	1, 2, 4		X	X		X		
Replace superheater loops	1, 2, 4		X	X		X		
Replace superheater assemblies	1, 2, 4			X	X		X	
Replace desuperheater liner assembly	2, 4			X	X	X		
Replace economizer assemblies	1, 2, 4			X	X		X	

continues

TABLE E-3 Continued

Activity	Category[a]	Estimated Frequency: 1 year	5 years	10 years	20 years	Percent Replacement Cost: <5	5-10	10-20
Chemical recovery furnace *continued*								
Replace generating bank tubes	1, 2, 4		X	X	X		X	
Complete NDE	1, 2, 3, 4	X				X		
Repair refractory	2, 4	X				X		
Clean and scaffold fire side	1, 2, 4	X				X		
Chemical recovery furnace auxiliaries								
Repair/rebuild ash-handling system	4	X	X			X		
Repair/rebuild green-liquor system	4	X	X			X		
Repair/rebuild dissolving-tank scrubber system	4	X	X			X		
Repair/rebuild dissolving tank	3, 4	X	X			X		
Repair/rebuild black-liquor system	4	X	X			X		
Repair/rebuild boiler safety relief valves	1, 2, 3	X				X		
Remove, calibrate, and simulate boiler protective interlock devices	1, 2, 3	X				X		
Repair/rebuild burner assemblies	4	X				X		
Repair/rebuild sootblowers	4	X				X		
Repair/rebuild direct-contact evaporators	4	X	X			X		
Rebuild direct-contact evaporators	4		X	X		X		
Repair steam-coil air heaters	4	X	X			X		
Replace steam-coil air heaters			X	X		X		
Repair/rebuild precipitator	4	X		X			X	
Repair/rebuild turbine drives	4		X			X		
Repair/rebuild forced-draft and induced-draft fans	4		X			X		
Upgrade safety systems to revised standards	1, 2, 3		X	X		X		

TABLE E-3 Continued

Activity	Category[a]	Estimated Frequency				Percent Replacement Cost		
		1 year	5 years	10 years	20 years	<5	5-10	10-20
Chemical recovery furnace auxiliaries *continued*								
Replace unsupported control hardware	4			X	X		X	
Inspect/repair stack	4		X			X		
Repair/rebuild ducts and flues	4		X			X		
Building structural repair	4				X	X		
Power-plant auxiliary devices								
Repair/rebuild deaerator	1,3		X	X	X	X		
Repair/rebuild demineralizers	4		X	X		X		
Repair/rebuild boiler-feedwater pumps	4	X	X			X		
Repair/rebuild air compressors	4	X	X			X		
Repair/rebuild air dryers	4	X	X			X		
Repair/rebuild demineralized-water transfer pumps	4	X	X			X		
Repair/rebuild condensate-transfer pumps	4	X	X			X		
Repair/rebuild condensate polishers	4		X	X		X		
Repair/rebuild condensate magnetic filters	4		X	X		X		
Repair/rebuild water softeners	4		X	X		X		
Repair/rebuild sand filters	4		X	X		X		
Repair/rebuild water clarifiers	4		X	X		X		
Repair/rebuild drive turbines	4	X	X			X		
Repair/rebuild uninterrupted power supply	4	X	X			X		
Repair/rebuild station batteries	4	X	X			X		
Repair/rebuild steam pressure relief valves and desuperheaters	4	X	X			X		
Repair/rebuild oil storage tanks	1, 4		X	X		X		

continues

TABLE E-3 Continued

Activity	Category[a]	Estimated Frequency 1 year	5 years	10 years	20 years	Percent Replacement Cost <5	5-10	10-20
Power-plant auxiliary devices *continued*								
Repair/rebuild woodwaste receiving equipment	4	X	X			X		
Inspect/repair woodwaste storage equipment	4	X	X			X		
Repair/rebuild coal receiving equipment	4	X	X			X		
Repair/rebuild coal storage equipment	4	X	X			X		
Repair/rebuild natural-gas piping	1, 4		X	X		X		
Repair/rebuild water storage tanks	4			X	X	X		

[a]Category:
1. Required by state regulatory agency or insurance carrier.
2. Required by company or industry standards.
3. Required to maintain safe operation.
4. Required to maintain reliable operation.
5. Required because of design deficiencies.
6. Required because of unforeseen operational problems.
7. Required because of unforeseen mechanical damage.

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