United States Environmental Protection Agency

Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations

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Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations

U.S. Environmental Protection Agency
Office of Air and Radiation

Air Quality Strategies and Standards Division,
Emission, Monitoring, and Analysis Division
and
Clean Air Markets Division

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CHAPTER 1

EXECUTIVE SUMMARY

Synopsis

EPA has estimated the benefits and costs of the Clean Air Visibility Rule or BART rule and finds that the rule results in estimated annual net benefits ranging from $1.9 to $12.0 billion in 2015. These alternate net benefit estimates reflect differing assumptions about State actions that may result from BART guidelines and different social discount rates of 3 and 7 percent used to estimate the social benefits and costs of the rule. In 2015, the total annual quantified benefits range from $2.2 to $14.3 billion and the annual social costs range from $300 million to $2.9 billion depending on the scenario analyzed and the social discount rate—benefits outweigh social costs in all scenarios analyzed. Visibility benefits in the Class I areas in the southeastern and southwestern United States, a subset of expected visibility benefits expected from the rule, range from $80 million to $420 million per year for the scenarios analyzed. Estimates do not include the value of benefits or costs that we cannot monetize. Upon consideration of the uncertainties and limitations in the analysis, it remains clear that the benefits of the Clean Air Visibility Rule are substantial and far outweigh the costs.

1.1 Background

On July 20, 2001 (66 FR 38108), the U.S. Environmental Protection Agency (EPA) proposed guidelines for implementing the best available retrofit technology (BART) requirements under the Regional Haze Rule. The proposed guidelines were intended to ease implementation of the Regional Haze Rule that was published on July 1, 1999 (64 FR 35714). We received numerous comments on the proposal. In addition, on May 24, 2002, the U.S. Court of Appeals for the D.C. Circuit issued a ruling striking down the Regional Haze Rule in part and upholding it in part. The court vacated the process for determining both (1) the sources to which BART must apply and (2) how a State should determine the level of control for each source subject to BART. To fully respond to the court's ruling, we reproposed the BART guidelines and the section of the Regional Haze Rule relevant to the BART guidelines on March 5, 2004. The reproposal reflects both our review of the public comments and our response to the court ruling.

This document presents estimates of the health and welfare benefits and the estimated costs of the BART program referred to officially as the Clean Air Visibility Rule (CAVR) in 2015. CAVR and BART are used interchangeably in this document to refer to this rule. This document recognizes that the recently signed Clean Air Interstate Rule (CAIR) will accomplish the requirements of BART for the power sector in the CAIR region where annual sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls are required. CAIR, as promulgated, will affect a 28-State and the District of Columbia (DC) region in the eastern United States, and the BART rule is applicable nationwide. This rule is applicable to the electric-generating sector (EGU) and 25 other source categories (non-EGU) sector.

1.2 Results

A comparison of the benefits and costs of the rule in 2015 is shown in Table 1-1. The benefits and costs reported for CAVR in Table 1-1 represent estimates assuming CAIR in the baseline that includes the CAIR promulgated rule and the concurrent proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware. The modeling used to provide CAIR baseline estimates also assumes annual SO_2 and NO_x controls for Arkansas that are not a part of the complete CAIR program resulting in an understatement of the reported benefits and costs for CAVR. The recently promulgated Clean Air Mercury Rule (CAMR) is not considered in the baseline for CAVR.

In this RIA, we have provided analyses for three different regulatory scenarios that provide information about the actions States may require to meet potential BART requirements for affected BART-eligible EGU and non-EGU sources. These scenarios should be viewed as illustrative, because States will make the ultimate decisions on the BART-eligible sources to control and levels of control based on the guideline criteria, other than for those sources where presumptive limits are applicable. The alternative scenarios analyzed provide a range of benefits, costs, and net benefits that may result from this rule. For more details of the alternative control scenarios assumptions see Chapters 2, 7, and 8 of this document. We believe State actions for BART for non-EGU sources are likely to fall somewhere within the range of alternatives presented in the analysis.

Additional details of the important analysis assumptions, including entities regulated, baseline, analysis year, control scenario, and other relevant analysis assumptions are discussed in Chapter 2 of this report.

Table 1-1. Summary of Annual Benefits, Costs, and Net Benefits of the Clean Air Visibility Rule—2015[a] (billions of 1999 dollars)

Description	Scenario 1	Scenario 2	Scenario 3
Social costs[b]			
3 percent discount rate	\$0.4	\$1.4	\$2.3
7 percent discount rate	\$0.3	\$1.5	\$2.9
Social benefits[c,d,e]			
3 percent discount rate	\$2.6 + B	\$10.1 + B	\$14.3 + B
7 percent discount rate	\$2.2 + B	\$8.6 + B	\$12.2 + B
Health-related benefits:			
3 percent discount rate	\$2.5	\$9.8	\$13.9
7 percent discount rate	\$2.1	\$8.4	\$11.8
Visibility benefits	\$0.08	\$0.24	\$0.42
Net benefits (benefits-costs)[e,f]			
3 percent discount rate	\$2.2 + B	\$8.7 + B	\$12.0 + B
7 percent discount rate	\$1.9 + B	\$7.1 + B	\$9.3 + B

[a] All estimates are rounded to two significant digits for ease of presentation and computation. A complete CAIR program that includes the CAIR promulgated rule and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware is assumed to because implemented in the baseline for the BART analysis. Annual SO_2 and NO_x controls for Arkansas are included in the modeling used to develop these estimates resulting in a minimal overstatement of the benefits and costs for the complete CAIR program and potentially a minimal understatement of the benefits and costs for BART. The impact of the recently promulgated CAMR was not been considered in the baseline for BART.

[b] Note that costs are the annualized total costs of reducing pollutants including NO_x and SO_2 for the EGU and non-EGU source categories nationwide in 2015. The discount rate used to conduct the analysis impacts the control strategies chosen for the non-EGU source category resulting in greater level of controls under the 3 percent discount rate for Scenario 1.

[c] As this table indicates, total benefits are driven primarily by particulate matter (PM)-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide (with the exception of visibility) and are associated with NO_x and SO_2 reductions. Visibility benefits represent benefits in Class I areas in the southeastern and southwestern United States. Ozone benefits are likely to occur with BART but are not estimated in this analysis.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit and disbenefit categories that have not been quantified and monetized are listed in Table 1-4.

[e] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 4. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

[f] Net benefits are rounded to the nearest \$100 million. Columnar totals may not sum due to rounding.

1.2.1 Health Benefits

CAVR is expected to yield significant health benefits by reducing emissions of two key contributors to fine particle and ozone formation. SO_2 contributes to the formation of fine particle pollution ($PM_{2.5}$), and NO_x contributes to the formation of both $PM_{2.5}$ and ground-level ozone.[1]

Our analyses suggest CAVR would yield total benefits in 2015 ranging from $2.6 to $14.3 billion (based on a 3 percent discount rate) and from $2.2 to $12.2 billion (based on a 7 percent discount rate). For Scenario 2, these benefits include the value of avoiding approximately 1,600 premature deaths, 2,200 nonfatal heart attacks, 960 hospitalizations for respiratory and cardiovascular diseases, 170,000 lost work days, and 1 million days when adults restrict normal activities because of respiratory symptoms exacerbated by $PM_{2.5}$ pollution.[2]

Because of schedule and resource limitations, EPA did not conduct a quantitative analysis of benefits from reductions (and potential disbenefits from increases) in ground-level ozone as a result of precursor emissions reductions projected for BART. However, it is unlikely that net benefits resulting from ozone reductions would have a significant impact on any conclusions reached regarding the overall benefits for this rulemaking.

We also estimate substantial additional health improvements for children from reductions in upper and lower respiratory illnesses, acute bronchitis, and asthma attacks. See Table 1-2 for a list of the annual reduction in health effects expected in 2015 and Table 1-3 for the estimated value of those reductions.

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[1] Although well over 90 percent of the expected benefits of this rule are derived from reductions in SO_2 and NO_x, a small portion of EPA's projected benefits are a result of reductions in primary PM from power plants. Although this reduction is not required by the rule, it is a potential ancillary benefit of installing certain SO_2 control technologies.

[2] These estimates account for growth in the public's willingness to pay for reductions in health and environmental risks and account for growth in real gross domestic product (GDP) per capita between the present and 2015. Benefit estimates reflect the use of 3 percent and 7 percent discount rates consistent with EPA and the Office of Management and Budget (OMB) guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

Table 1-2. Clean Air Visibility Rule: Estimated Reduction in Incidence of Adverse Health Effects in 2015[a,b]

Health Effect	Incidence Reduction		
	Scenario 1	**Scenario 2**	**Scenario 3**
PM-Related Endpoints:			
Premature mortality[c]			
Adult, age 30 and over	400	1,600	2,300
Infant, age <1 year	1	4	5
Chronic bronchitis (adult, age 26 and over)	230	890	1,300
Nonfatal myocardial infarction (adults, age 18 and older)	570	2,200	3,000
Hospital admissions—respiratory (all ages)[d]	140	510	720
Hospital admissions—cardiovascular (adults, age >18)[e]	120	450	640
Emergency room visits for asthma (age 18 years and younger)	370	1,300	1,800
Acute bronchitis (children, age 8–12)	550	2,100	3,000
Lower respiratory symptoms (children, age 7–14)	6,600	25,000	36,000
Upper respiratory symptoms (asthmatic children, age 9–18)	5,000	19,000	27,000
Asthma exacerbation (asthmatic children, age 6–18)	8,100	31,000	44,000
Work loss days (adults, age 18–65)	44,000	170,000	240,000
Minor restricted-activity days (MRADs) (adults, age 18–65)	260,000	1,000,000	1,400,000

[a] Incidences are rounded to two significant digits. These estimates represent benefits from CAVR nationwide. The modeling used to derive these incidence estimates assumes the final CAIR program in the baseline including the CAIR promulgated rule and the proposal to include SO_2 and annual NO_x controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_x controls for Arkansas for CAIR resulting in a slight understatement of the reported benefits and costs for the CAVR. The recently promulgated CAMR has not been considered in the baseline for CAVR.

[b] Ozone benefits are expected for CAVR but are not estimated for this analysis.

[c] Adult premature mortality based on studies by Pope et al. (2002). Infant premature mortality is based on studies by Woodruff, Grillo, and Schoendorf (1997).

[d] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia, and asthma.

[e] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 1-3. Estimated Monetary Value of Reductions in Incidence of Health and Welfare Effects for the Clean Air Visibility Rule in 2015 (in millions of 1999$)[a,b]

Effect	Scenario 1	Scenario 2	Scenario 3
Health Effects:			
Premature mortality[c,d]			
Adult >30 years			
3% discount rate	$2,330	$9,180	$13,000
7% discount rate	$1,960	$7,730	$10,900
Child <1 year	$6.12	$23.8	$34.2
Chronic bronchitis (adults, 26 and over)	$90.5	$353	$498
Nonfatal acute myocardial infarctions			
3% discount rate	$49.3	$189	$264
7% discount rate	$45.8	$176	$245
Hospital admissions for respiratory causes	$1.07	$4.03	$5.65
Hospital admissions for cardiovascular causes	$2.6	$10.0	$14.1
Emergency room visits for asthma	$0.106	$0.362	$0.51
Acute bronchitis (children, age 8–12)	$0.207	$0.79	$1.12
Lower respiratory symptoms (children, 7–14)	$0.109	$0.415	$0.587
Upper respiratory symptoms (asthma, 9–11)	$0.137	$0.523	$0.74
Asthma exacerbations	$0.367	$1.4	$1.98
Work loss days	$5.56	$22.4	$31.5
Minor restricted-activity days (MRADs)	$13.8	$54.1	$76.3
Welfare Effects:			
Recreational visibility, southeastern and southwestern Class I areas	$84	$239	$416
Monetized Total[e]			
Base Estimate:			
3% discount rate	$2,600 + B	$10,100 + B	$14,300 + B
7% discount rate	$2,200 + B	$8,600 + B	$12,200 + B

[a] Monetary benefits are rounded to three significant digits. These estimates are nationwide with the exception of visibility benefits. Ozone benefits are expected for CAVR but have not been estimated for this analysis. Visibility benefits relate to Class I areas in the southeastern and southwestern United States. The benefit estimates assume the final CAIR program in the baseline that includes the CAIR promulgated rule and the proposal to include SO_2 and annual NO_x controls for New Jersey and Delaware. Modeling used to develop the CAIR baseline estimates assumes annual SO_2 and NO_x controls for Arkansas resulting in a slight understatement of the reported benefits and costs for CAVR. The recently promulgated CAMR is not considered in the baseline for CAVR.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year of 2015.

[c] Valuation assumes discounting over the Science Advisory Board (SAB)-recommended 20-year segmented lag structure described in Chapter 4. Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

[d] Adult premature mortality based on studies by Pope et al. (2002). Infant premature mortality based on studies by Woodruff, Grillo, and Schoendorf (1997).

[e] B represents the monetary value of health and welfare benefits and disbenefits not monetized. A detailed listing is provided in Table 1-4. Totals are rounded to the nearest 100 million, and totals may not sum due to rounding.

1.2.2 Welfare Benefits

The term *welfare benefits* covers both environmental and societal benefits of reducing pollution, such as reductions in damage to ecosystems; improved visibility; and improvements in recreational and commercial fishing, agricultural yields, and forest productivity. Although we are unable to monetize all welfare benefits, EPA estimates CAVR will yield welfare benefits of approximately $240 million in 2015 (1999$) for visibility improvements in southeastern and southwestern (including California) Class I (national park) areas for Scenario 2.

1.2.3 Uncertainty in the Benefits Estimates

Characterization of health-related benefits associated with PM reductions is a complex process that is subject to a variety of potential sources of uncertainty. Key assumptions underlying the estimate of avoided premature mortality include the following:

- Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been established, the weight of the available epidemiological and experimental evidence supports an assumption of causality.
- All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.
- The concentration-response (C-R) function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with the fine particle standards and those that do not meet the standard.
- The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Use of the Pope et al. (2002)-derived mortality function to support this analysis is associated with uncertainty resulting from (a) potential of the study to incompletely capture short-term exposure-related mortality effects, (b) potential mismatch between study and analysis populations, which introduces various forms of bias into the results, and (c) failure to identify all key confounders and effects modifiers that could result in incorrect effects estimates relating morality to $PM_{2.5}$ exposure. EPA is researching methods to characterize all elements of uncertainty in the dose-response function for mortality. As is discussed in detail in the CAIR RIA (EPA, 2005), EPA has used two methods to quantify uncertainties in the mortality function, including the statistical uncertainty derived from the standard errors reported in the Pope et al. (2002) study and the use of results of a pilot expert elicitation conducted in 2004 to investigate other uncertainties in the mortality estimate. Because this analysis is an illustrative analysis, we do not quantify uncertainty with these two methods in this report. In the CAIR benefit analysis, the statistical uncertainty from the standard error of the Pope et al. (2002) study was twice the mean benefit estimate at the 95th percentile and one-fourth of the mean at the 5th percentile, while the expert elicitation provided mean estimates that ranged in value from less than one-third of the mean estimate from the Pope et al. (2002) study-based estimate to two-and-one-half times the Pope et al. (2002)-based estimate. The confidence intervals from the pilot elicitation applied to the CAIR benefit analysis ranged in value from zero at the 5th percentile to a value at the 95th percentile that is seven times higher than the Pope et al. (2002)-based estimate. These results are highly dependent on the air quality scenarios applied to the C-R functions of the Pope et al. (2002) study and the pilot expert elicitation. Thus, the characterization of uncertainty discussed in the CAIR RIA could differ greatly from what would be observed for CAVR because of differences in population-weighted changes in concentrations of $PM_{2.5}$ (i.e., the location of populations' exposure relative to the changes in air quality) and may be especially sensitive to the differences in baseline $PM_{2.5}$ air quality experienced by populations prior to implementation of the CAVR. EPA is continuing its research of methods to characterize uncertainty in total benefits estimates and is conducting a full-scale expert elicitation. The full-scale expert elicitation is scheduled to be completed by the end of 2005.

1.3 Not All Benefits Quantified

EPA was unable to quantify or monetize all of the health and environmental benefits associated with CAVR. EPA believes these unquantified benefits are substantial, including the value of increased agricultural crop and commercial forest yields, visibility improvements, and reductions in nitrogen and acid deposition and the resulting changes in ecosystem functions. Table 1-4 provides a list of these benefits.

Table 1-4. Unquantified and Nonmonetized Effects of the Clean Air Visibility Rule

Pollutant/Effect	Effects Not Included in Primary Estimates—Changes in:
Ozone—Health[a]	• Premature mortality[b] • Chronic respiratory damage • Premature aging of the lungs • Nonasthma respiratory emergency room visits • Increased exposure to UVb • Hospital admissions: respiratory • Emergency room visits for asthma • Minor restricted-activity days • School-loss days • Asthma attacks • Cardiovascular emergency room visits • Acute respiratory symptoms
Ozone—Welfare	• Yields for: – commercial forests, – fruits and vegetables, and – commercial and noncommercial crops • Damage to urban ornamental plants • Recreational demand from damaged forest aesthetics • Ecosystem functions • Increased exposure to UVb
PM—Health[c]	• Premature mortality: short-term exposures[d] • Low birth weight • Pulmonary function • Chronic respiratory diseases other than chronic bronchitis • Nonasthma respiratory emergency room visits • Exposure to UVb (+/-)[e]
PM—Welfare	• Visibility in many Class I areas • Residential and recreational visibility in non-Class I areas • Soiling and materials damage • Ecosystem functions • Exposure to UVb (+/-)[e]
Nitrogen and Sulfate Deposition—Welfare	• Commercial forests due to acidic sulfate and nitrate deposition • Commercial freshwater fishing due to acidic deposition • Recreation in terrestrial ecosystems due to acidic deposition • Existence values for currently healthy ecosystems • Commercial fishing, agriculture, and forests due to nitrogen deposition • Recreation in estuarine ecosystems due to nitrogen deposition • Ecosystem functions • Passive fertilization due to nitrogen deposition

(continued)

Table 1-4. Unquantified and Nonmonetized Effects of the Clean Air Visibility Rule (continued)

Pollutant/Effect	Effects Not Included in Primary Estimates—Changes in:
Mercury Health[g]	• Incidence of neurological disorders • Incidence of learning disabilities • Incidence of developmental delays • Potential reproductive effects[f] • Potential cardiovascular effects[f], including: – Altered blood pressure regulation[f] – Increased heart rate variability[f] – Incidence of myocardial infarction[f]
Mercury Deposition[g] **Welfare**	• Impacts on birds and mammals (e.g., reproductive effects) • Impacts to commercial, subsistence, and recreational fishing

[a] In addition to primary economic endpoints, a number of biological responses have been associated with ozone health effects including increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Premature mortality associated with ozone is not currently included in the primary analysis. Recent evidence suggests that short-term exposures to ozone may have a significant effect on daily mortality rates, independent of exposure to PM. EPA is currently conducting a series of meta-analyses of the ozone mortality epidemiology literature. EPA will consider including ozone mortality in primary benefits analyses once a peer-reviewed methodology is available.

[c] In addition to primary economic endpoints, a number of biological responses have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[d] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort study on which the primary analysis is based.

[e] May result in benefits or disbenefits. See discussion in Section 5.3.4 for more details.

[f] These are potential effects because the literature is insufficient.

[g] Mercury emission reductions are not anticipated for BART from the EGU source category because the cap-and-trade program promulgated for the CAMR (March 2005); however, the geographic location of mercury reductions may change as a result of this rule. EPA believes any such effects for these sources would likely be minimal. Mercury reductions are expected for the non-EGU source categories. The mercury reductions for BART from the non-EGU source categories are expected to be small compared to reductions resulting from the recently promulgated CAIR and CAMR (March 2005).

1.4 Costs and Economic Impacts

The control strategies analyzed in this report represent EPA's best approximation of the emission controls for BART-eligible sources that States may require. Ultimately, States will make the determination of those BART-eligible sources to control and the level of cost-effective controls. We recognize the uncertainty in these estimates and present benefit and cost estimates for three scenarios.

For the affected region, the projected annual incremental private costs of CAVR to the power industry range from $253 to $896 million in 2015. These costs represent the total cost to the electricity-generating industry of reducing NO_x and SO_2 emissions to meet the BART requirements set out in the rule assuming alternative control scenarios. Estimates are in 1999 dollars. Costs of the rule are estimated using the Integrated Planning Model (IPM) and assume firms make decisions using costs of capital ranging from 5.34 percent to 6.74 percent.

In estimating the net benefits of regulation, the appropriate cost measure is "social costs." Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. Under Scenario 2, the social costs of this rule for the EGU sector are estimated to range from $119 to $688 million in 2015 and assuming a 3 or 7 percent discount rate.

Average retail electricity prices are projected to increase roughly 0.1 percent with CAVR in the 2015 time frame for Scenario 2. Coal-fired generation as well as coal production and natural gas-fired generation under CAVR are projected to remain essentially unchanged relative to CAIR baseline levels. It is also not expected that CAVR will change the composition of new generation built to meet growth in electricity demand. CAVR is also not expected to impact coal or natural gas prices.

For the non-EGU sectors, we estimate that emission control costs will range from approximately $151 million to $2.2 billion in 2015 for the alternative regulatory scenarios and at a 3 or 7 percent discount rate. These estimates are based on an analysis conducted that assumes States will implement controls with a maximum cost ranging from $1,000 to $10,000 per ton of SO_2 or NO_x emission reductions.

1.5 Limitations

Every analysis examining the potential benefits and costs of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and variability or uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe this benefit-cost analysis provides a reasonable indication of the expected economic benefits and costs of CAVR in future years.

A major source of uncertainty in the analysis conducted for this RIA is the uncertainty surrounding the actions States may take to comply with BART. We have conducted a range of scenarios that represent increasing levels of stringency of controls

States may require to implement BART. It is likely that the benefits and costs of BART as required by States will fall within the range of estimates presented in this document.

For this analysis, such uncertainties include possible errors in measurement and projection for variables such as population growth and baseline incidence rates, uncertainties associated with estimates of future-year emissions inventories and air quality, variability in the estimated relationships between changes in pollutant concentrations and the resulting changes in health and welfare effects, and uncertainties in exposure estimation. We have used sensitivity analyses to address these limitations where possible.

EPA's cost estimates do not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal and other compliance strategies, such as fuel switching or the reductions in their costs over time. EPA projections also do not take into account demand response (i.e., consumer reaction to electricity prices), because the consumer response is likely to be relatively small, but the effect on lowering private compliance costs may be substantial. Costs may be understated since an optimization model was employed and the regulated community may not react in the same manner to comply with the rules. The Agency also did not consider transactional costs and/or savings from BART on the labor supply.

1.6 References

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SECTION 2

INTRODUCTION AND BACKGROUND

For this rulemaking, we are developing guidelines for BART determinations under the regional haze regulations. Specifically, we are addressing the issues of: 1) the sources that must apply BART, and 2) guidance as to how a State should determine the level of control for each source subject to BART in response to the court's ruling. We are finalizing a reproposal of the BART guidelines and the section of the regional haze rule relevant to the BART guidelines. This final rule reflects both our review of the public comments, and our response to the court ruling.

This document presents the health and welfare benefits of the Clean Air Visibility Rule (CAVR) or BART rule and compares the benefits of this rule to the estimated costs of implementing the rule in 2015. This section provides background information including a discussion of the need for the proposed regulation, a brief discussion of the potentially regulated source categories, and control scenarios analyzed in the RIA.

2.1 Background

In 1999, the EPA published a final rule to address a type of visibility impairment known as regional haze 64 FR 35714, July 1, 1999. The regional haze rule requires state implementation plans (SIPs) to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. These 156 scenic areas are called "Class I areas" in the Clean Air Act (CAA). This rule fulfilled a long-standing EPA commitment to address regional haze under the authority and requirements of sections 169A and 169B of the CAA.

As required by section 169A(b)(2)(A) and 169A(g) of the CAA, we included in the final regional haze rule a requirement for BART for certain large stationary sources that were put in place between 1962 and 1977. We discussed these requirements in detail in the preamble to the final rule. (See 64 FR 35737-35743). The regulatory requirements for BART are codified at 40 CFR 51.308(e), and in the definitions that appear in 40 CFR 51.301.

The CAA, in 169A(b)(2)(A) and in 169A(g)(7), uses the term "major stationary source" to describe those sources that are the focus of the BART requirement. To avoid confusion with other CAA requirements that also use the term "major stationary source" to refer to a somewhat different population of sources, the regional haze rule uses the term "BART-eligible source" to describe these sources. BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place or under construction between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. Under CAA section 169A(b)(2)(A), BART is required for any BART-eligible source which "emits any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area." Accordingly, for stationary sources meeting these criteria, States must address the BART requirement when they develop their regional haze SIPs.

Section 169A(g)(7) of the Clean Air Act requires that States must consider the following factors in making BART determinations:

(1) the costs of compliance,

(2) the energy and nonair quality environmental impacts of compliance,

(3) any existing pollution control technology in use at the source,

(4) the remaining useful life of the source, and

(5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

These statutory factors for BART appear in the regional haze rule in 40 CFR 51.308(e)(1)(ii).

The regional haze rule provides States with two alternative ways to approach the requirement for BART in the CAA. Under the first approach, contained in 51.308(e)(1) of the regional haze rule, SIPs would contain source specific emission limits for each source subject to BART. Under the second approach, States may elect to adoptive alternative measures, such as a regional emissions trading program, in lieu of BART so long as the alternative measures achieve "more reasonable progress" than would application of source-specific BART emission limits. In the preamble to the 1999 regional haze rule, we discuss a number of issues related to both approaches.

In addition, in the preamble to the regional haze rule (64 FR 35741, July 1, 1999) we committed to issuing further guidelines to clarify the requirements of the BART provision. The purpose of this rule is to fulfill this commitment by providing guidelines for States to use in identifying their BART eligible sources, in identifying those sources that must undergo a detailed BART analysis (i.e., "sources subject to BART"), and in conducting the technical analysis of possible controls in light of the statutory factors listed above ("the BART determination").

Finally, the rule discusses proposed changes to the regional haze rule, and a reproposal of the BART guidelines, in response to the May 24, 2002 ruling from the US Court of Appeals for the D.C. Circuit, that struck down the regional haze rule in part (and upheld it in part). This rulemaking finalizes guidelines for States to use in identifying their BART eligible sources, in identifying those sources that must undergo a detailed BART analysis.

2.2 Regulated Source Categories

This action does not directly regulate emissions sources. Instead, it requires States and Tribes with BART-eligible stationary sources to revise their implementation plans to meet the BART requirements. However, States have the flexibility to choose what sources to control. The CAA uses the following 26 source category titles to describe the types of stationary sources that are BART-eligible:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units (Btu) per hour heat input,

(2) Coal cleaning plants (thermal dryers),

(3) Kraft pulp mills,

(4) Portland cement plants,

(5) Primary zinc smelters,

(6) Iron and steel mill plants,

(7) Primary aluminum ore reduction plants,

(8) Primary copper smelters,

(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,

(10) Hydrofluoric, sulfuric, and nitric acid plants,

(11) Petroleum refineries,

(12) Lime plants,

(13) Phosphate rock processing plants,

(14) Coke oven batteries,

(15) Sulfur recovery plants,

(16) Carbon black plants (furnace process),

(17) Primary lead smelters,

(18) Fuel conversion plants,

(19) Sintering plants,

(20) Secondary metal production facilities,

(21) Chemical process plants,

(22) Fossil-fuel boilers of more than 250 million BTUs per hour heat input,

(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,

(24) Taconite ore processing facilities,

(25) Glass fiber processing plants, and

(26) Charcoal production facilities.

Most of the source category titles are general descriptors that are inclusive of all the operations at a given plant. Some plant sites may have more than one of the categories present. Examples of this would include plants with both "petroleum refineries" and "sulfur recovery plants," or with both "iron and steel mill plants" and "sintering plants." On the other hand, some plant sites may include some emissions units meeting one of these 26 descriptions, but other emissions units that do not.

2.3 Control Scenarios

The source-specific BART guidelines require emissions reductions from sources emitting sulfur dioxides (SO_2) and nitrous oxides (NO_x). The analyses conducted for this RIA include three regulatory alternative scenarios that States may choose to follow to comply with BART. The alternatives include three scenarios of increasing stringency - Scenario 1, Scenario 2, and Scenario 3. A brief discussion of the these alternatives for the electric generating units (EGUs) and all other sources follows. More details of the alternative control scenarios and associated control costs are discussed in chapters 7 and 8 of this report.

2.3.1 Electric Generating Units

In the revised BART guidelines, we have included presumptive control levels for SO_2 and NO_x emissions from coal-fired electric generating units greater than 200 megawatts (MW) in capacity at plants greater than 750 MW in capacity. Given the similarities of these units to other BART-eligible coal-fired units greater than 200 MW at plants 750 MW or less, EPA's guidance suggests that states control such units at similar levels for BART. The guidelines would require 750 MW power plants to meet specific control levels of either 95 percent control or controls of 0.15 lbs/MMBtu, for each EGU greater than 200 MW, unless the State determines that an alternative control level is justified based on a careful consideration of the statutory factors.[1] Thus, for example, if the source convincingly demonstrates unique circumstances affecting its ability to cost-effectively reduce its emissions, the State may take that into account in determining whether the presumptive levels of control are appropriate for the facility. For an EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, States may also find that such controls are cost-effective when taking into consideration the costs of compliance in the BART analysis in applying the five factor test for the BART determination. In our analysis we have assumed that no additional controls will occur where units have existing scrubbers and that no controls will occur for oil-fired units. While these levels may represent current control capabilities, we expect that scrubber technology will continue to improve and control costs will continue to decline.

For NO_x, for those large EGUs that have already installed selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) during the ozone season, States should require the same controls for BART. However, those controls should be required to operate year-round for BART. For sources currently using SCR or SNCR for part of the year, States should presume that the use of those same controls year-round is highly cost-effective. For other sources, the guidelines establish presumptive emission levels that vary depending largely upon boiler type and fuel burned. For coal-fired cyclone units with a size greater than 200 MW, our analysis assumes these units will install SCR. For all other coal-fired units, our analysis assumed these units will install current combustion control

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[1] These levels are commonly achievable by flue gas desulfurization controls ("scrubbers").

technology. In addition, we assume no additional controls for oil and/or gas-fired steam units.

We present alternative regulatory scenarios. Scenario 2 represents our application of the presumptive limits described above to all BART eligibility EGUs greater than 200 MW. For Scenario 1, we assume that only 200 MW BART-eligible EGUs located at facilities above 750 MW capacity will comply with the SO_2 requirements and NO_x controls. In this scenario, no facilities less than 750 MW capacity are assumed to install BART controls. For Scenario 1, we assume that units with existing SCRs will operate those SCR units year round annually. In contrast in Scenario 3, we analyzed SO_2 controls equivalent to 95 percent reductions or 0.1 lbs per MMBtu on all previously uncontrolled units. NO_x controls for this most stringent scenario presume SCRs will be installed on all units greater than 100 MW capacity and combustion controls will be installed on units greater than 25 MW but less than 100 MW capacity. The EPA analyzed the costs of each BART scenario using the Integrated Planning Model (IPM). The EPA has used this model extensively in past rulemakings to analyze the impacts of regulations on the power sector.

The analysis presented assumes that BART-eligible EGUs affected by the Clean Air Interstate Rule (CAIR) (March 2005) have met the requirements of this rule. Thus, no additional controls for EGUs beyond CAIR are anticipated or modeled for the 28 State plus District of Columbia CAIR region. In addition, we are assuming no additional SO_2 controls for sources located in States of Arizona, Utah, Oregon, Wyoming, and New Mexico or Tribal lands located in these States due to agreements made with the Western Regional Air Partnership (WRAP). See Chapter 7 for a more detailed discussion of the emission controls scenarios assumed for the EGU sector. An analysis of EGU controls under CAIR and a more conservative approach to BART controls for EGU sources is included in Appendix E of this report. This analysis provides information as to the possible incremental benefits and costs associated with requiring EGU controls for BART sources in the non-CAIR region. It should be noted that a more strict interpretation of BART than in the BART guidelines finalized was assumed for this analysis and that the costs and benefits for BART reported in Appendix E differ from those estimated for the three regulatory scenarios analyzed for this rulemaking.

2.3.2 Sources Other than Electric Generating Units

As previously discussed there are 25 source categories potentially subject to BART in addition to EGUs (referred to as non-EGU source categories) as defined by the CAA. The EPA evaluated a set of SO_2 and NO_x emission control technologies available for these source categories and estimated the associated costs of control using AirControlNET. The control scenarios evaluated assume maximum control measure cost caps of $1,000 per ton (Scenario 1), $4,000 per ton (Scenario 2), and $10,000 per ton (Scenario 3). The EPA also conducted a cost analysis for $2,000 per ton and $3,000 per ton, and the results of this analysis are presented in Appendix G of this document. The analysis consists of applying SO_2 and NO_x controls to each non-EGU source category up to the specified cost per ton cap in each scenario. These cost per ton caps are specified in average cost terms. As control stringency is increased, the marginal costs are also estimated for each non-EGU source category. The scenarios examined are based on the costs of technologies such as scrubbers for SO_2 control, and varying types of technologies for NO_x control. Scrubbers are the most common type of SO_2 control for most non-EGU sources for each scenario, while combustion controls such as low NO_x burners (LNB) and post-combustion controls such as selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) are commonly applicable to most of the non-EGU source category. Combustion controls are commonly applied as part of Scenario 1, while SNCR and SCR are more commonly applied either by themselves or in combination with combustion controls as part of Scenarios 2 and 3. Analyses are not available for 8 of the 25 non-EGU source categories, because there are no available control measures for these sources or there are no sources in these categories included in the non-EGU emissions data utilized in these analyses. The marginal costs of these alternative regulatory scenarios are presented along with the results of these analyses in Chapter 8 of this report. All of these results are estimated using a nationwide database of BART-eligible non-EGU sources that is based on information collected from Regional Planning Organizations (RPOs) in the fall of 2004. This database became part of the baseline for this analysis. More information on this non-EGU source database is available in Chapter 3 of this report. Just as for affected EGUs, all impacts to non-EGUs are estimated for the year 2015.

2.4 Baseline and Years of Analysis

The final rule on which this analysis is based sets forth the requirements for States and Tribes to meet the BART guidelines of the Regional Haze Rule. To comply with the BART guidelines, EPA requires that certain States reduce their emissions of SO_2 and NO_x. The Agency considered all promulgated CAA requirements and known state actions in the baseline used to develop the estimates of benefits and costs for this rule including the recently promulgated Clean Air Interstate Rule. However, EPA did not consider actions States may take to implement the ozone and $PM_{2.5}$ NAAQS standards nor the recently promulgated Clean Air Mercury Rule in the baseline for this analysis.

In the analysis, the controls and reductions are assumed to be required in 2015, a date that is generally consistent with the expected timing of the rule. States must submit SIPs relevant to the BART requirements in January 2008. After approval of the SIP, there is a 5 year compliance date. Thus, controls are likely to be installed by the end of 2013 or the beginning of 2014 to comply with the rule. In addition, EPA had existing inventories, modeling, and base case runs for 2015 to use for the analysis. The year 2015 is used in this analysis. All estimates presented in this report represent annualized estimates of the benefits and costs of CAVR in 2015 rather than the net present value of a stream of benefits and costs in these particular years of analysis.

2.5 Organization of this Report

This document describes the health and welfare benefits of the proposed rule. The document is organized as follows:

- Chapter 3, Emissions and Air Quality Impacts, describes emission inventories and air quality modeling that are essential inputs into the benefits assessment.
- Chapter 4, Benefits Analysis and Results, describes the methodology and results of the benefits analysis.
- Chapter 5, Qualitative Assessment of Nonmonetized Benefits, describes benefits that are not monetized for this rulemaking.
- Chapter 6, Profile of Potentially Affected Industries, describes the major industries that may be affected by this rule.
- Chapter 7, Cost and Economic Impacts for the EGU Sector, describes the costs of the rule to the power section and related economic impacts.
- Chapter 8, Results of Cost, Emission Reductions, and Economic Impact Analysis for the Non-Electricity Generating Sectors, describes the costs of the rule to affected industry sectors and related economic impacts.
- Chapter 9, Executive Order and Statutory Requirements, describes impact analyses conducted to meet executive order and statutory requirements.
- Chapter 10, Comparison of Benefits and Costs, provides a comparison of the monetized benefits and estimated annual costs of the proposed rule.
- Appendix A, BART Industry-Sector Impacts
- Appendix B, Cost and Economic Impact Supplemental Information and Sensitivity Analyses

- Appendix C, Additional Technical Information Supporting the Benefits Analysis
- Appendix D, Visibility Benefits Methodology
- Appendix E, Benefits and Costs of the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Interstate Rule Plus the Clean Air Visibility Rule
- Appendix F, Sensitivity Analyses of Some Key Parameters in the Benefits Analysis
- Appendix G, Additional Control Scenarios for Non-EGU Source Categories

SECTION 3

EMISSIONS AND AIR QUALITY IMPACTS

This chapter summarizes the emissions inventories and air quality modeling that serve as the inputs to the benefits analysis of this rule as detailed in Chapter 4. EPA uses sophisticated photochemical air quality models to estimate baseline and post-control ambient concentrations of PM and deposition of nitrogen and sulfur for each year. The estimated changes in ambient concentrations are then combined with monitoring data to estimate population-level exposures to changes in ambient concentrations for use in estimating health effects. Modeled changes in ambient data are also used to estimate changes in visibility and changes in other air quality statistics that are necessary to estimate welfare effects.

Section 3.1 of this chapter summarizes the baseline emissions inventories and the emissions reductions that were modeled for this rule. Section 3.2 summarizes the methods for and results of estimating air quality for the 2015 base case and control scenarios for the purposes of the benefits analysis. There are separate sections for PM and visibility.

3.1 Emissions Inventories and Estimated Emissions Reductions

The emission sources and the basis for current and future-year emission inventories for BART are listed in Table 3-1. The data source for the EGU source category is the 2001 base year data from the Acid Rain Trading Program. Modeling of the potential BART emission controls for the EGU source category including potential emission reductions from the program was completed with the IPM. The data source for the non-EGU BART eligible source categories is the 2001 National Emission Inventory (NEI). Data necessary to identify potentially affected BART eligible non-EGU sources were provided by the RPOs in response to an Information Collection Request. More details concerning the development of the emissions inventory data may be found in the Emissions Inventory Technical Support Document (Emissions Inventory TSD) available in the docket for this rule. Modeling of the potential BART emission controls for the non-EGU source category, including potential emission reductions from the program, was completed using AirControlNet.

Table 3-1. Emissions Sources and Basis for Current and Future-Year Inventories[a,b]

Sector or Source	Emissions Source	2001 Base Year	Future-Year Base Case Projections
EGU	Power industry EGUs	2001 Data from the Acid Rain Trading Program	IPM
Non-EGU	Non-utility point, including point source fugitive dust	2001 NEI	Baseline including CAIR control case: (1) Department of Energy (DOE) fuel use projections, (2) Regional Economic Model, Inc. (REMI) Policy Insight® model, (3) decreases to REMI results based on trade associations, Bureau of Labor Statistics (BLS) projections and Bureau of Economic Analysis (BEA) historical growth from 1987 to 2002, (4) control assumptions BART control cases: All of the above plus AirControlNET controls applied to BART-eligible units
Average Fire	Wildfire, prescribed burning	Same as future year	Average fires from 1996 through 2002 (based on state total acres burned), with the same emissions rates and country distributions of emissions as in the 2001 NEI
Average Fire	Agricultural burning, open burning	2001 NEI	2001 NEI
Agriculture	Livestock NH_3	2002 preliminary NEI[c]	2015 emissions estimated with the same approach as was used for the 2002 preliminary NEI[c]
Agriculture	Fertilizer NH_3	2001 NEI	2001 NEI

(continued)

Table 3-1. Emissions Sources and Basis for Current and Future-Year Inventories[a,b] (continued)

Sector or Source	Emissions Source	2001 Base Year	Future-Year Base Case Projections
Area	All other stationary area sources, including area-source fugitive dust	1999 NEI, version 3 grown to 2001	(1) DOE fuel use projections, (2) REMI Policy Insight Model, (3) decreases to REMI results based on trade associations, BLS projections and BEA historical growth from 1987–2002
On-road	Highway vehicles	Mobile6.2 model	Projected vehicle miles traveled same as CAIR proposed and final rule, emissions from MOBILE6.2 model
Nonroad	Locomotives, commercial marine vessels, and aircraft	2001 NEI; CMV adjusted to new national totals from Office of Transportation Air Quality (OTAQ)	Grown based on national totals from OTAQ, using state/county distribution of emissions from the 2001 NEI
Nonroad	All other nonroad vehicles	NONROAD 2004 model	NONROAD 2004 model

[a] This table documents only the sources of data for the U.S. inventory. The sources of data used for Canada and Mexico are explained in the emissions inventory TSD and were held constant from the base year to the future years.

[b] All fugitive dust emissions were adjusted downward using county-specific transportable fractions needed as part of the current state of the art in air quality modeling.

[c] ftp://ftp.epa.gov/EmisInventory/prelim2002nei/nonpoint/documentation/nh3inventorydraft_jan2004.pdf.

The emissions inventories used for the BART analysis builds on a baseline inventory that includes CAIR promulgated March 10, 2005. The CAIR TSD for emissions inventories discusses the development of the 2001, 2015 baseline prior to CAIR emission controls, and 2015 baseline including the 2015 CAIR emission controls (CAIR control case). The CAIR control case provides the emissions inventory baseline for the BART analysis conducted. The CAIR TSD is available as follows: http://www.epa.gov/interstateairquality/pdfs/finaltech01.pdf

Table 3-2 summarizes the 2001 baseline, 2015 CAIR control case (2015 base case for BART), and three 2015 BART control case scenarios of NO_X and SO_2 emissions. Table 3-3 shows the change in NO_X and SO_2 emissions for each of the three BART control case scenarios that were used in modeling air quality changes: Scenario 1, Scenario 2, and Scenario 3. The emission reductions for these control case scenarios relate to the EGU and non-EGU source categories that are potentially affected by the BART guidelines. For details on EPA's IPM results including emission reductions for the EGU sector, see Chapter 7 of this RIA. For details on EPA's AirControlNET modeling of potential non-EGU emission reductions see Chapter 8 of this RIA. The BART emissions inventories TSD discusses the development of the 2015 CAVR inventories used to develop the benefits analysis for this final rule.

3.2 Air Quality Impacts

This section summarizes the methods for and results of estimating air quality for the 2015 base case and control scenarios for the purposes of the benefits analysis. EPA has focused on the health, welfare, and ecological effects that have been linked to air quality changes. These air quality changes include the following:

1. Ambient particulate matter ($PM_{2.5}$), as estimated using a national-scale applications of the Community Multi-Scale Air Quality (CMAQ) model, and

2. Visibility degradation (i.e., regional haze), as developed using empirical estimates of light extinction coefficients and efficiencies in combination with CMAQ-modeled reductions in pollutant concentrations.

The air quality estimates in this section are based on the emission changes summarized in the preceding section. These air quality results are in turn associated with human populations and ecosystems to estimate changes in health and welfare effects. In Section 3.2.1, we describe the estimation of PM air quality using CMAQ, and in Section 3.2.2, we discuss the estimation of visibility degradation.

Table 3-2. Summary of Modeled Baseline Emissions, CAIR Control Case, and BART Control Strategies

	Pollutant Emissions (tons)	
Source	**NO_X**	**SO_2**
2001 Baseline[a]		
EGUs	4,937,398	10,901,127
Non-EGUs	2,942,618	2,958,692
Average Fire	238,931	49,108
Area	1,462,276	1,295,146
On-road	8,064,067	271,026
Nonroad	4,050,655	433,250
Total, All Sources	21,695,945	15,908,349
2015 Base CAIR Control Case[a]		
EGUs	2,172,839	5,111,436
Non-EGUs	3,183,499	3,422,915
Average Fire	238,931	49,108
Area	1,702,154	1,480,348
On-road	3,152,562	30,824
Nonroad	2,912,382	232,627
Total, All Sources	13,362,365	10,327,258
2015 BART, Scenario 1[b]		
EGUs	2,057,220	5,057,652
Non-EGUs	3,011,944	3,338,983
Total, All Sources	13,075,193	10,189,543
2015 BART, Scenario 2[b]		
EGUs	1,963,753	4,991,850
Non-EGUs	2,807,124	3,152,277
Total, All Sources	12,776,906	9,937,034
2015 BART, Scenario 3[b]		
EGUs	1,740,551	4,958,975
Non-EGUs	2,779,816	3,043,903
Total, All Sources	12,526,397	9,795,785

[a] The “ag” sector does not have emissions of NO_x and SO_2.

[b] With the exception of EGUs and non-EGUs, all other sectors are the same as the CAIR control case (CAVR baseline) for 2015.

Table 3-3. Summary of Modeled Emissions Changes for the BART Rule: 2015[a]

Item	Pollutant NO_X	Pollutant SO_2
2015 Emission Reductions with the BART, Scenario 1		
Total Ton Reductions	287,172	137,715
Percentage of EGU Emission Reductions	5.3%	1.1%
Percentage of Non-EGU Emission Reductions	5.4%	2.5%
Percent Reduction of All Manmade Emissions	2.1%	1.3%
2015 Emission Reductions with BART, Scenario 2		
Total Tons Reduction	585,459	390,224
Percentage Reduction of EGU Emissions	9.6%	2.3%
Percentage of Non-EGU Emission Reduction	11.8%	7.9%
Percentage Reduction of All Manmade Emissions	4.4%	3.8%
2015 Emission Reductions with BART, Scenario 3		
Total Tons Reduction	835,968	531,473
Percentage Reduction of EGU Emissions	19.9%	3.0%
Percentage of Non-EGU Emission Reduction	12.7%	11.1%
Percentage Reduction of All Manmade Emissions	6.3%	5.1%

[a] Note that the emission changes and percentage changes reported are nationwide estimates.

3.2.1 PM Air Quality Estimates

We use the emissions inputs summarized above with a national-scale application of the CMAQ modeling system to estimate PM air quality in the contiguous United States. CMAQ is a three-dimensional grid-based Eulerian air quality model designed to estimate annual particulate concentrations and deposition over large spatial scales (e.g., over the contiguous United States). Consideration of the different processes that affect primary (directly emitted) and secondary (formed by atmospheric processes) PM at the regional scale in different locations is fundamental to understanding and assessing the effects of pollution control measures that affect PM, ozone, and deposition of pollutants to the surface.[1] Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, CMAQ is useful for evaluating the impacts of the rule on U.S. PM concentrations. Our analysis applies the modeling system to the entire United States for the five emissions scenarios: a 2001 base year, a 2015 base year projection, and three 2015 projections with varying levels of emissions controls.

The CMAQ version 4.3 was employed for this BART modeling analysis (Byun and Schere, 2004). This version reflects updates in a number of areas to improve performance and address comments from the peer review, including (1) the formation of nitrates based on updated gaseous/heterogeneous chemistry and a current inorganic nitrate partitioning module, (2) a state-of-the-science secondary organic aerosol (SOA) module that includes a more comprehensive gas-particle partitioning algorithm from both anthropogenic and biogenic SOA, (3) an in-cloud sulfate chemistry that accounts for the nonlinear sensitivity of sulfate formation to varying pH, and (4) the updated CB-IV gas-phase chemistry mechanism and aqueous chemistry mechanism that provide a comprehensive simulation of aerosol precursor oxidants.

CMAQ simulates every hour of every day of the year and, thus, requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include hourly emissions estimates and meteorological data in every grid cell and a set of pollutant concentrations to initialize the model and to specify concentrations along the modeling domain boundaries. These initial and boundary concentrations were obtained from output of a global chemistry model. As discussed below, we use the model predictions in a relative sense by first determining the ratio of species predictions between the 2001 base year and each future-year scenario. The calculated relative change is then combined with the corresponding ambient species measurements to project concentrations for the future case scenarios. The annual mean PM air quality is used as input to the health and welfare C-R functions of the benefits analysis. The following sections provide a more detailed discussion of each of the steps in this evaluation and a summary of the results.

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[1]Given that a large percentage of $PM_{2.5}$ concentrations and visibility degradation is due to secondarily formed particles (e.g., sulfates) it is important to employ a Eulerian model such as CMAQ. The formation and fate of secondarily formed pollutants typically involve emissions of precursor pollutants (e.g., SO_2) from a multitude of widely dispersed sources coupled with chemical and physical processes that are best addressed using an air quality model that employs a Eulerian grid model design.

3.2.1.1 Modeling Domain

As shown in Figure 3-1, the modeling domain encompasses the lower 48 States and extends from approximately 126 degrees to 66 degrees west longitude and from 24 degrees north latitude to 52 degrees north latitude. The modeling domain is segmented into rectangular blocks referred to as grid cells. The model actually predicts pollutant concentrations for each of these grid cells. For this application the horizontal grid cells are 36 km by 36 km. In addition, the modeling domain contains 14 vertical layers with the top of the modeling domain at about 16,200 meters, or 100 mb. Within the domain each vertical layer has 16,576 grid cells.

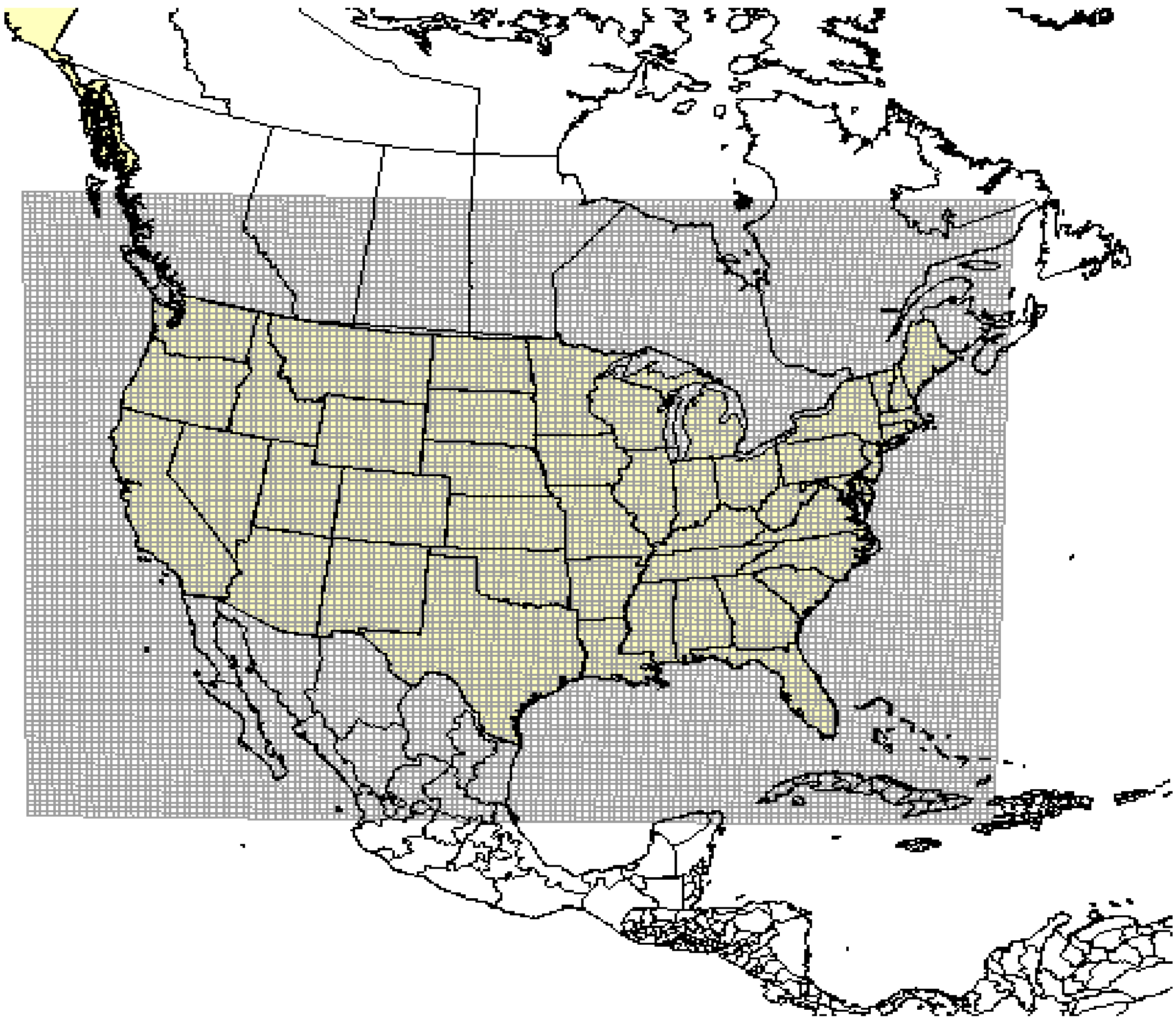

Figure 3-1. CMAQ Modeling Domain

3.2.1.2 Simulation Periods

For use in this benefits analysis, the simulation periods modeled by CMAQ included separate full-year application for each of the five emissions scenarios (i.e., 2001 base year and the 2015 base case and control scenarios).

3.2.1.3 Model Inputs

CMAQ requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data and initial and boundary conditions. Separate emissions inventories were prepared for the 2001 base year and the future-year base case and control scenarios. All other inputs were specified for the 2001 base year model application and remained unchanged for each future-year modeling scenario.

CMAQ requires detailed emissions inventories containing temporally allocated emissions for each grid cell in the modeling domain for each species being simulated. The previously described annual emission inventories were preprocessed into model-ready inputs through the emissions preprocessing system. Details of the preprocessing of emissions are provided in the *Clean Air Interstate Rule Emissions Inventory Technical Support Document* (EPA, 2005a). Meteorological inputs reflecting 2001 conditions across the contiguous United States were derived from version 5 of the Mesoscale Model (MM5). These inputs include horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer.

The lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry and transport model (GEOS-CHEM). The lateral boundary species concentrations varied with height and time (every 3 hours). Terrain elevations and land use information were obtained from the U.S. Geological Survey database at 10 km resolution and aggregated to the 36 km horizontal resolution used for this CMAQ application. Further details on the CMAQ model setup can be found in the CAIR Air Quality Modeling Technical Support Document (EPA, 2005b).

3.2.1.4 CMAQ Model Evaluation

An operational model performance evaluation for $PM_{2.5}$ and its related speciated components (e.g., sulfate, nitrate, elemental carbon, organic carbon), and deposition of ammonium, nitrate, and sulfate for 2001 was performed to estimate the ability of the CMAQ modeling system to replicate base-year concentrations. This evaluation principally comprises statistical assessments of model versus observed pairs that were paired in time and space on a daily or weekly basis, depending on the sampling period of measured data. The statistics are presented separately for the entire domain, the East, and the West (using the 100th meridian to divide the eastern and western United States). In addition, scatterplots of seasonal average and annual average predictions versus observations paired by site are included in the model performance evaluation. A spatial analysis was also performed for sulfate and nitrate to examine how well the modeling platform (year-specific meteorology, anthropogenic and biogenic emissions, and boundary conditions representative of 2001) predicts the spatial patterns and gradients evident from the observations. The details of these analyses can be found in "CMAQ Model Performance Evaluation for 2001: Updated March 2005" (EPA, 2005c).

For $PM_{2.5}$ species, this evaluation includes comparisons of model predictions to the corresponding measurements from the Clean Air Status and Trends Network (CASTNet) and the Speciation Trend Network (STN) in addition to measurements from the Interagency Monitoring of PROtected Visual Environments (IMPROVE). The CASTNet dry deposition monitoring network contained a total of 79 sites in 2001, with a total number of 56 sites located in the East and 23 sites located in the West. Sulfate and total nitrate data were used in the evaluation. CASTNet data are collected and reported as weekly average data. The data are collected in filter packs that sample the ambient air continuously during the week. The sulfate data are of high quality because sulfate is a stable compound. However, the particulate nitrate concentration data collected by CASTNet are known to be problematic and subject to volatility because of the length of the sampling period. CASTNet also reports a total nitrate measurement, which is the combination of particulate nitrate and nitric acid. Because the total nitrate measurement is not affected by this sampling problem, it is considered a more reliable measurement. Therefore, we chose to use the total nitrate data and not to use the particulate nitrate data in this evaluation.

The EPA STN network began operation in 1999 to provide nationally consistent speciated $PM_{2.5}$ data for the assessment of trends at representative sites in urban areas. STN reports mass concentrations and $PM_{2.5}$ constituents, including sulfate, nitrate, ammonium, and elemental and organic carbon. Most STN sites collect data on a frequency of 1 in every 3 days, (some supplemental sites are collected 1 in every 6 days). For the 2001 analysis, CMAQ predictions were evaluated against 133 STN sites (105 sites in the East and 28 sites in the West).

The IMPROVE network is a cooperative visibility monitoring effort between EPA, Federal land management agencies, and State air agencies. Data are collected at Class I areas across the United States mostly at national parks, national wilderness areas, and other protected pristine areas. Approximately 134 IMPROVE rural/remote sites had complete annual $PM_{2.5}$ mass and/or $PM_{2.5}$ species data for 2001. Eighty-six sites were in the West, and 48 sites were in the East. IMPROVE data are collected once in every 3 days.

The principal evaluation statistics used to evaluate CMAQ performance are the fractional bias and fractional error. Fractional bias is defined as:

$$FBIAS = \frac{2}{N} \sum_{i=1}^{N} \frac{(Pred_{x,t}^{i} - Obs_{x,t}^{i})}{(Pred_{x,t}^{i} + Obs_{x,t}^{i})} * 100$$

Fractional bias is a useful model performance indicator because it has the advantage of equally weighting positive and negative bias estimates. Fractional error is similar to fractional bias except the absolute value of the difference is used so that the error is always positive. Fractional error is defined as:

$$FERROR = \frac{2}{N} \sum_{i=1}^{N} \frac{\left|Pred_{x,t}^{i} - Obs_{x,t}^{i}\right|}{Pred_{x,t}^{i} + Obs_{x,t}^{i}} * 100$$

These metrics were calculated annually for all IMPROVE, CASTNet, STN, and National Atmospheric DePosition (NADP) sites for the East and West individually.

Currently, there are no universally accepted performance criteria for judging the adequacy of $PM_{2.5}$ model performance. However, performance can be judged by comparison to model performance results found by other groups in the air quality modeling community. In this respect, we have compared our CMAQ 2001 model performance results to the range of performance found in other recent regional $PM_{2.5}$ model applications by other groups. These modeling studies represent a broad range of modeling analyses that cover various models, model configurations, domains, years and/or episodes, chemical mechanisms, and aerosol modules. The fractional bias and fractional error statistics were calculated using the predicted-observed pairs for the full year of 2001 and for each season, separately. The statistics for the full year are provided in Table 3-4. Overall, the performance is within the range or close to that found by other groups in recent applications. It should be noted that

Table 3-4. Model Performance Statistics for BART CMAQ 2001

CAIR CMAQ 2001 Annual			Fractional Bias (%)	Fractional Error (%)
$PM_{2.5}$ Total Mass	STN	East	–12	44
		West	–51	64
	IMPROVE	East	8	43
		West	14	57
Sulfate	STN	East	8	45
		West	–32	52
	IMPROVE	East	7	40
		West	–2	49
	CASTNet	East	–2	24
		West	–35	50
Nitrate	STN	East	–12	86
		West	–92	115
	IMPROVE	East	–32	107
		West	–44	115
Total Nitrate ($NO_3 + HNO_3$)	CASTNet	East	16	81
		West	–60	105
Elemental Carbon	STN	East	32	63
		West	–20	67
	IMPROVE	East	–23	51
		West	–13	66
Organic Carbon	STN	East	–3	75
		West	–31	66
	IMPROVE	East	–10	52
		West	51	76

sulfate (especially in the summer) accounts for the vast majority of visibility degradation in the East. Model performance statistics for summer average sulfate is provided in Table 3-5. The general range of model performance for $PM_{2.5}$ species compares favorably to fractional bias and fractional error statistics from the better performing model applications found by others in the modeling community, as follows:

- summer sulfate is in the range of –10 percent to +30 percent for fractional bias and 35 percent to 50 percent for fractional error and
- winter nitrate is in the range of +50 percent to +70 percent for fractional bias and 85 percent to 105 percent for fractional error.

Table 3-5. Selected Performance Evaluation Statistics from the CMAQ 2001 Simulation

Eastern United States		CMAQ 2001 Fractional Bias (%)	CMAQ 2001 Fractional Error (%)
Sulfate (Summer)	STN	14	44
	IMPROVE	10	42
	CASTNet	3	22

Thus, CMAQ is considered appropriate for use in projecting changes in future year $PM_{2.5}$ concentrations and the resultant health/economic benefits due to the emissions reductions.

3.2.1.5 Converting CMAQ Outputs to Benefits Inputs

CMAQ generates predictions of hourly PM species concentrations for every grid. The species include a primary coarse fraction (corresponding to PM in the 2.5 to 10 micron size range), a primary fine fraction (corresponding to PM less than 2.5 microns in diameter), and several secondary particles (e.g., sulfates, nitrates, and organics). $PM_{2.5}$ is calculated as the sum of the primary fine fraction and all of the secondarily formed particles. Future-year estimates of $PM_{2.5}$ were calculated using relative reduction factors (RRFs) applied to 2002 ambient $PM_{2.5}$ and $PM_{2.5}$ species concentrations. A gridded field of $PM_{2.5}$ concentrations was created by interpolating Federal Reference Monitor ambient data and IMPROVE ambient data. Gridded fields of $PM_{2.5}$ species concentrations were created by interpolating EPA speciation network (ESPN) ambient data and IMPROVE data. The ambient data were interpolated to the CMAQ 36 km grid.

The procedures for determining the RRFs are similar to those in EPA's draft guidance for modeling the $PM_{2.5}$ standard (EPA, 2001). This guidance has undergone extensive peer review and is anticipated to be finalized this year. The guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. The procedure for calculating future-year $PM_{2.5}$ design values is called the "Speciated Modeled Attainment Test (SMAT)." EPA used this procedure to estimate the ambient impacts of the CAIR NPR emissions controls. The SMAT procedures for BART (and for CAIR) have been revised. Full documentation of the revised SMAT methodology is contained in "Procedures for Estimating Future $PM_{2.5}$ Values for the CAIR

Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT)-Updated" (EPA, 2004).

The revised SMAT uses an FRM mass construction methodology that results in reduced nitrates (relative to the amount measured by routine speciation networks, such as ESPN), higher mass associated with sulfates (reflecting water included in FRM measurements), and a measure of organic carbonaceous mass that is derived from the difference between measured $PM_{2.5}$ and its noncarbon components. This characterization of $PM_{2.5}$ mass also reflects crustal material and other minor constituents. The resulting characterization provides a complete mass balance. It does not have any unknown mass that is sometimes presented as the difference between measured $PM_{2.5}$ mass and the characterized chemical components derived from routine speciation measurements. The revised SMAT methodology uses the following $PM_{2.5}$ species components: sulfates, nitrates, ammonium, organic carbon mass, elemental carbon, crustal, water, and blank mass (a fixed value of 0.5 ug/m^3). In each grid cell, the $PM_{2.5}$ component species mass adds up to the interpolated $PM_{2.5}$ mass.

For the purposes of projecting future $PM_{2.5}$ concentrations for input to the benefits calculations, we applied the SMAT procedure using the base-year 2001 modeling scenario and each of the future-year scenarios. In our application of SMAT we used temporally scaled speciated $PM_{2.5}$ monitor data from 2002 as the set of base-year measured concentrations. Temporal scaling is based on ratios of model-predicted future case $PM_{2.5}$ species concentrations to the corresponding model-predicted 2001 concentrations. Output files from this process include both quarterly and annual mean $PM_{2.5}$ mass concentrations, which are then manipulated within SAS to produce a BenMAP input file containing 364 daily values (created by replicating the quarterly mean values for each day of the appropriate season).

The SMAT procedures as documented for use in CAIR are applicable for projecting future nonattainment counties and downwind receptor areas for the transport analysis. Those procedures are the same as those performed for the BART PM benefits analysis with the following exceptions:

1) The BART benefits analysis uses interpolated $PM_{2.5}$ data that cover all of the grid cells in the modeling domain (covering the entire country), whereas the CAIR nonattainment analysis is performed at each ambient monitoring site in the East using measured $PM_{2.5}$ data (only the species data are interpolated).

2) The benefits analysis is anchored by the interpolated $PM_{2.5}$ data from the single year of 2002, whereas the nonattainment analysis uses a 5-year weighted average (1999–2003) of $PM_{2.5}$ design values at each monitoring site.

3.2.1.6 PM Air Quality Results

Table 3-6 summarizes the projected $PM_{2.5}$ concentrations for the 2015 base case and changes associated with the rule. The table includes the annual mean concentration averaged across all model grid cells in the nation, along with the average change between base and control concentrations. We also provide the population-weighted average that better reflects the baseline levels and predicted changes for more populated areas of the nation. This measure, therefore, better reflects the potential benefits of these predicted changes through exposure changes to these populations. As shown, the average annual mean concentration of $PM_{2.5}$ across populated eastern U.S. grid cells declines by roughly 1.28 percent (or 0.12 $\mu g/m^3$) in 2015. The population-weighted average mean concentration declined by 0.94 percent (or 0.10 $\mu g/m^3$) in 2015 for Scenario 2. Comparable estimates for Scenario 1 reflect smaller PM air quality improvements than for Scenario 2, and estimates for Scenario 3 show greater air quality improvements. This information is presented in Table 3-6.

Table 3-7 provides information on the populations in 2015 that will experience improved PM air quality. As shown, in 2015, almost 35.4 percent of the U.S. population is predicted to experience reductions of greater than 0.1 $\mu g/m^3$. Furthermore, over 8 percent of this population will benefit from reductions in annual mean $PM_{2.5}$ concentrations of greater than 0.2 $\mu g/m^3$.

3.2.2 Visibility Degradation Estimates

Visibility degradation is often directly proportional to decreases in light transmittal in the atmosphere. Scattering and absorption by both gases and particles decrease light transmittance. To quantify changes in visibility, our analysis computes a light-extinction coefficient, based on the work of Sisler (1996), which shows the total fraction of light that is decreased per unit distance. This coefficient accounts for the scattering and absorption of light by both particles and gases and accounts for the higher extinction efficiency of fine particles compared to coarse particles. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon (soot), and soil (Sisler, 1996).

Table 3-6. Summary of Base Case PM Air Quality and Changes Due to Clean Air Visibility Rule in 2015

Region	$PM_{2.5}$ ($\mu g/m^3$)	Base Case	Scenario 1 Change[a]	Scenario 1 Percent Change	Scenario 2 Change[a]	Scenario 2 Percent Change	Scenario 3 Change[a]	Scenario 3 Percent Change
East	Average[b] Annual Mean	9.39	–0.04	–0.43	–0.12	–1.28	–0.16	–1.70
	Population-Weighted Average Annual Mean [c]	10.64	–0.03	–0.28	–0.10	–0.94	–0.14	–1.32
West	Average Annual Mean	6.04	–0.02	–0.33	–0.04	–0.66	–0.06	–0.99
	Population-Weighted Average Annual Mean[c]	12.46	–0.01	–0.08	–0.07	–0.56	–0.10	–0.80

[a] The change is defined as the control case value minus the base case value.

[b] Calculated as the average across all grid cells in the U.S. portion of the region.

[c] Calculated by summing the product of the population and the projected annual mean PM concentration for each grid cell then dividing this sum by the total regional population.

Table 3-7. Distribution of $PM_{2.5}$ Air Quality Improvements Over Population Due to Clean Air Visibility Rule in 2015

Range of Change in Annual Mean $PM_{2.5}$ Concentrations ($\mu g/m^3$)[a]	Scenario 1 Number (millions)	Scenario 1 Percent (%)	Scenario 2 Number (millions)	Scenario 2 Percent (%)	Scenario 3 Number (millions)	Scenario 3 Percent (%)
≤ 0.1	301.7	95.2%	204.6	64.6%	130.8	41.3%
0.11 – 0.20	9.9	3.1%	85.6	27.0%	136.3	43.0%
0.21 – 0.30	5.2	1.6%	19.6	6.2%	35.5	11.1%
0.31 – 0.40	0.0	0.0%	5.1	1.6%	9.2	2.9%
0.41 – 0.50	0.0	0.0%	1.9	0.6%	2.7	0.8%
0.50 – 0.60	0.0	0.0%	0.0	0.0%	2.4	0.8%

[a] The change is defined as the control case value minus the base case value.

[b] Population counts and percentages are for the continental U.S. population.

Based on the light-extinction coefficient, we also calculated a unitless visibility index, called a "deciview," that is used in the valuation of visibility. The deciview metric provides a scale for perceived visual changes over the entire range of conditions, from clear to hazy. Under many scenic conditions, the average person can generally perceive a change of one deciview. The higher the deciview value, the worse the visibility. Thus, an improvement in visibility is a decrease in deciview value.

3.2.2.1 Procedures for Estimating Visibility Degradation

The impacts of the BART emissions reductions were examined in terms of the projected improvement in annual average visibility as well as projected visibility improvement on the 20 percent best and worst days from 2001 at Class I areas. We quantified visibility impacts at the 116 Class I areas that have complete IMPROVE ambient data for 2001 or are represented by IMPROVE monitors with complete data.[2] Currently 110 IMPROVE monitoring sites (representing all 156 Class I areas) are collecting ambient $PM_{2.5}$ data at Class I areas, but only 81 of these sites have complete data for 2001.

The future-year base and BART control visibility was calculated using a methodology that applies modeling results in a relative sense similar to SMAT. The draft $PM_{2.5}$ and Regional Haze modeling guidance recommends the calculation of future-year changes in visibility in a similar manner to the calculation of changes in $PM_{2.5}$. We generally followed the procedures in the guidance.

In calculating visibility impairment, the extinction coefficient and deciview values are made up of individual component species (e.g., sulfate, nitrate, organics). The predicted change in visibility is calculated as the percentage change in the extinction coefficient for each of the PM species (on a daily average basis). The individual daily species extinction coefficients are summed to get a daily total extinction value. The daily extinction coefficients are converted to deciviews and then averaged across all monitored days to get an annual average as well as the 20 percent best and worst days (best and worst days separately). In this way, we can calculate an average change in deciviews from the base case to a future case at each Class I area. Additionally, subtracting the future BART control case deciview values from the future base case deciview values gives an estimate of the visibility

[2]There are 81 IMPROVE sites with complete data for 2001. Many of these sites collect data that are "representative" of other nearby unmonitored Class I areas. A total of 116 Class I areas are represented by the 81 sites. The matching of sites to monitors is taken from "Guidance for Tracking Progress Under the Regional Haze Rule."

benefits in Class I areas from the BART scenario. Additional details on the visibility calculation methodology can be found in the CAIR "Better-than-BART" TSD (EPA, 2005d).

As explained above (Section 3.2.1.5), when calculating future-year $PM_{2.5}$ concentrations for BART, we have updated the SMAT procedures to use $PM_{2.5}$ component species that emulate the FRM measurements. This is thought to be the most accurate estimate of the $PM_{2.5}$ species fractions at FRM sites for the purpose of calculating PM-related health benefits. For visibility calculations, we are continuing to use the IMPROVE program species definitions and visibility formulas that are recommended in the draft modeling guidance. Each IMPROVE site has measurements of $PM_{2.5}$ species; therefore, we do not need to estimate the species fractions in the same way that we did for FRM sites (using interpolation techniques and other assumptions concerning volatilization of species). Therefore, the methodology for calculating $PM_{2.5}$ species fractions for the visibility calculations (at IMPROVE sites) differs from the calculations that are detailed in the revised SMAT methodology.

Table 3-8 provides visibility improvements expected to occur in specific parks in the nation for Scenario 2. As shown, major parks in the United States, including the Great Smokey Mountains and Shenandoah, are expected to see improvements in visibility. By 2015, on the 20 percent of worst visibility days, the Great Smokey Mountains National Park is expected to see improvements of over 0.15 deciviews (0.59 percent), and Shenandoah National Park is expected to see improvements of over 0.24 deciviews (1.02 percent). It is important to note that the deciview changes reported are estimated with CAIR in the baseline. This means visibility improvements for CAIR controls that meet BART requirements are not reflected in the deciview impacts shown in this table.

Table 3-8. Summary of Deciview Visibility Impacts at Class I Areas in the Nation[a,b] Scenario 2

Federal Class I Area	2015 Change in Average of 20% Worst Days	Percent Change in Average of 20% Worst Days	Change in Annual Average	Percent Change in Annual Average
Acadia, ME	0.09	0.41	0.05	0.39
Aqua Tibia, CA*	0.20	0.87	0.14	0.79
Alpine Lakes, WA	0.10	0.58	0.10	0.84
Anaconda- Pintler, MT	0.04	0.30	0.03	0.36
Arches, UT*	0.00	0.00	0.03	0.40
Badlands, SD	0.32	1.87	0.21	1.77
Bandelier, NM*	0.08	0.66	0.04	0.50
Big Bend, TX	0.04	0.22	0.05	0.40
Black Canyon of the Gunnison, CO*	0.06	0.61	0.06	0.80
Bob Marshall, MT	0.02	0.13	0.02	0.20
Boundary Waters Canoe Area, MN	0.20	1.04	0.09	0.77
Bridger, WY	0.06	0.56	0.04	0.62
Brigantine, NJ	0.11	0.43	0.06	0.30
Bryce Canyon, UT*	0.06	0.49	0.05	0.61
Cabinet Mountains, MT	0.03	0.23	0.03	0.35
Caney Creek, AR	0.19	0.78	0.27	1.46
Canyonlands, UT*	0.03	0.29	0.04	0.53
Cape Romain, SC	0.14	0.61	0.11	0.61
Caribou, CA*	0.06	0.46	0.04	0.55
Carlsbad Cavern, NM*	0.06	0.36	0.05	0.44
Chassahowitzka, FL*	0.10	0.44	0.07	0.37
Chiricahua, AZ*	0.08	0.59	0.04	0.47
Craters of the Moon, ID	0.07	0.51	0.04	0.43
Desolation, CA*	0.06	0.41	0.04	0.48
Dolly Sods, WV*	0.16	0.69	0.10	0.58
Dome Land, CA*	0.06	0.33	0.03	0.25
Eagle Cap, OR	0.09	0.49	0.05	0.44
Eagles Nest, CO*	0.07	0.67	0.05	0.73
Emigrant, CA*	0.05	0.30	0.02	0.21
Everglades, FL*	–0.01	–0.05	0.02	0.11
Fitzpatrick, WY	0.06	0.56	0.04	0.62

(continued)

Table 3-8. Summary of Deciview Visibility Impacts at Class I Areas in the Nation [a,b] Scenario 2 (continued)

	2015			
Federal Class I Area	Change in Average of 20% Worst Days	Percent Change in Average of 20% Worst Days	Change in Annual Average	Percent Change in Annual Average
Flat Tops, CO*	–0.03	–0.28	0.02	0.32
Galiuro, AZ*	0.09	0.67	0.04	0.47
Gates of the Mountains, MT	0.02	0.19	0.02	0.32
Gila, NM*	0.08	0.67	0.03	0.40
Glacier, MT	0.02	0.13	0.02	0.18
Glacier Peak, WA	0.05	0.38	0.04	0.55
Grand Teton, WY	0.05	0.36	0.03	0.44
Great Gulf, NH	0.04	0.20	–0.04	–0.30
Great Sand Dunes, CO*	0.07	0.62	0.07	0.80
Great Smokey Mountains, TN*	0.15	0.59	0.11	0.56
Guadalupe Mountains, TX	0.08	0.44	0.05	0.43
Hells Canyon, OR	0.06	0.31	0.03	0.30
Isle Royale, MI	0.23	1.06	0.10	0.77
James River Face, VA*	0.15	0.62	0.08	0.42
Jarbidge. MV*	0.02	0.19	0.05	0.66
Joshua Tree, CA*	0.06	0.32	0.05	0.40
Joyce Kilmer—Slickrock, NC*	0.15	0.59	0.11	0.56
Kalmiopsis, OR	0.05	0.36	0.02	0.25
Kings Canyon, CA*	0.05	0.22	0.03	0.18
La Garita, CO*	0.04	0.42	0.04	0.58
Lassen Volcanic, CA*	0.06	0.45	0.04	0.53
Lava Beds, CA*	0.05	0.34	0.03	0.33
Linville Gorge, NC*	0.25	1.01	0.15	0.84
Lostwood, ND	0.21	1.08	0.09	0.64
Lye Brook, VT	0.14	0.62	0.06	0.44
Mammoth Cave, KY*	0.13	0.49	0.11	0.52
Marble Mountain, CA*	0.04	0.26	0.02	0.18
Maroon Bells- Snowmass, CO*	0.08	0.81	0.05	0.71
Mazatzal, AZ*	0.04	0.35	0.03	0.26
Medicine Lake, MT	0.10	0.55	0.06	0.45
Mesa Verde, CO*	0.08	0.70	0.05	0.59
Mingo, MO	0.14	0.52	0.16	0.78
Mission Mountains, MT	0.01	0.08	0.01	0.17
Mokelumne, CA*	0.05	0.39	0.03	0.37

(continued)

Table 3-8. Summary of Deciview Visibility Impacts at Class I Areas in the Nation[a,b] Scenario 2 (continued)

Federal Class I Area	2015			
	Change in Average of 20% Worst Days	Percent Change in Average of 20% Worst Days	Change in Annual Average	Percent Change in Annual Average
Moosehorn, ME	0.06	0.29	0.04	0.27
Mount Hood, OR	0.07	0.55	0.05	0.55
Mount Jefferson, OR	0.05	0.40	0.03	0.38
Mount Ranier, WA	0.09	0.50	0.06	0.48
Mount Washington, OR	0.05	0.35	0.03	0.33
Mount Zirkel, CO*	–0.03	–0.25	0.04	0.53
Noth Cascades, WA	0.04	0.30	0.04	0.53
Okefenokee, GA*	0.17	0.69	0.14	0.73
Otter Creek, WV	0.19	0.81	0.11	0.64
Pasauten. WA	0.07	0.44	0.05	0.65
Petrified Forest, AZ*	0.08	0.70	0.06	0.65
Pine Mountain, AZ	0.04	0.28	0.04	0.38
Presidential Range—Dry, NH*	0.11	0.55	0.05	0.35
Rawah, CO*	0.09	0.82	0.08	1.05
Red Rock Lakes, WY	0.04	0.31	0.03	0.42
Redwood, CA*	0.06	0.40	0.03	0.25
Rocky Mountain, CO*	0.07	0.49	0.06	0.67
Roosevelt Campobello, ME	0.08	0.39	0.06	0.40
Salt Creek, NM*	0.09	0.52	0.09	0.73
San Gorgonio, CA*	0.08	0.38	0.06	0.43
San Jacinto, CA *	0.11	0.53	0.10	0.69
San Pedro Parks, NM*	0.05	0.46	0.05	0.62
Sawtooth, ID	0.02	0.16	0.02	0.23
Scapegoat, MT	0.01	0.08	0.02	0.17
Selway—Bitterroot, MT	0.04	0.31	0.03	0.36
Seney, MI	0.20	0.85	0.10	0.72
Sequoia, CA*	0.07	0.30	0.05	0.28
Shenandoah, VA*	0.24	1.02	0.15	0.85
Sierra Ancha, AZ*	0.04	0.33	0.03	0.26
Sipsey, AL*	0.08	0.30	0.08	0.41
South Warner, CA*	0.04	0.32	0.03	0.37
Strawberry Mountain, OR	0.08	0.45	0.03	0.31
Superstition, AZ*	0.04	0.42	0.04	0.39
Swanquarter, NC*	0.09	0.77	0.09	0.50

(continued)

Table 3-8. Summary of Deciview Visibility Impacts at Class I Areas in the Nation[a,b] Scenario 2 (continued)

	2015			
Federal Class I Area	Change in Average of 20% Worst Days	Percent Change in Average of 20% Worst Days	Change in Annual Average	Percent Change in Annual Average
Sycamore Canyon, AZ*	0.02	0.15	0.02	0.17
Teton, WY	0.04	0.36	0.03	0.42
Theodore Roosevelt, ND	0.17	1.00	0.10	0.82
Thousand Lakes, CA*	0.06	0.45	0.04	0.53
Three Sisters, OR	0.05	0.35	0.03	0.33
UL Bend, MT	0.04	0.26	0.03	0.27
Upper Buffalo, AR	0.20	0.86	0.25	1.39
Voyageurs, MN	0.08	0.49	–0.11	–0.99
Weminuche, CO*	0.06	0.56	0.05	0.65
West Elk, CO*	0.03	0.25	0.03	0.53
Wind Cave, SD	0.21	1.38	0.13	1.31
Wolf Island, GA*	0.16	0.65	0.10	0.51
Yellowstone, WY	0.04	0.35	0.03	0.42
Yolla Bolly—Middle Eel, CA*	0.04	0.21	0.03	0.29
Yosemite, CA*	0.04	0.26	0.01	0.12
Zion, UT*	0.04	0.33	0.05	0.54

[a] The change is defined as the base case (includes CAIR controls) value minus the control case value for Scenario 2. This means the visibility changes from CAIR controls that meet the BART requirements are not reflected in the deciview impacts shown on this table.

[b] The percentage change is the "Change" divided by the "Base Case" and then multiplied by 100 to convert the value to a percentage.

* Visibility benefits were monetized for this park.

Negative values indicate visibility degradation.

3.3 References

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CHAPTER 4

BENEFITS ANALYSIS AND RESULTS

This chapter reports EPA's analysis of a subset of the public health and welfare impacts and associated monetized benefits to society of CAVR. EPA is required by Executive Order (E.O.) 12866 to estimate the benefits and costs of major new pollution control regulations. Accordingly, the analysis presented here attempts to answer three questions: (1) what are the physical health and welfare effects of changes in ambient air quality resulting from reductions in precursors to PM including NO_x and SO_2 emissions? (2) what is the monetary value of the changes in these effects attributable to the final rule? and (3) how do the monetized benefits compare to the costs? It constitutes one part of EPA's thorough examination of the relative merits of this regulation.

The analysis presented in this chapter uses a methodology consistent with the benefits analysis performed for the recent analysis of CAIR (EPA, 2005). The benefits analysis relies on three major modeling components:

1) Calculation of the impact of CAVR on eligible EGU and non-EGU sources assuming a program. This rule directs States and Tribes to establish SO_2 and NO_x controls for BART-eligible sources. These controls are expected to impact primarily EGU sources outside of the CAIR region (see Chapter 7 for more details) and non-EGU sources nationwide. Because of the nature of the CAIR banking and trading program for SO_2 and NO_x, there are also expected to be changes in emissions at EGU sources in the Eastern U.S. CAIR region due to changes in the relative marginal costs of electricity production.[1]

[1] Note that CAIR as promulgated does not include utilities in New Jersey, Delaware, or Arkansas. However, a rulemaking has been proposed to include New Jersey and Delaware in the CAIR region. The emissions and air quality modeling conducted for CAVR anticipated the inclusion of these States in the CAIR region and thus included them in CAIR for the purpose of projecting future conditions in 2015. The inclusion of Arkansas in the CAIR region for purposes of establishing the baseline for CAVR would tend to understate the emission reductions and benefits estimated for CAVR. In addition, the impacts of the recently promulgated CAMR were not considered in the baseline.

2) Air quality modeling for 2015 to determine changes in visibility and in ambient concentrations of PM, reflecting baseline and postcontrol emissions inventories.

3) A benefits analysis to determine the changes in human health and welfare, both in terms of physical effects and monetary value, that result from the projected changes in visibility and ambient concentrations of PM.

A wide range of human health and welfare effects are linked to the emissions of NO_x and SO_2 from BART-eligible sources and the resulting impact on visibility and on ambient concentrations of ozone and PM. Potential human health effects associated with $PM_{2.5}$ range from premature mortality to morbidity effects linked to long-term (chronic) and short-term (acute) exposures (e.g., respiratory and cardiovascular symptoms resulting in hospital admissions, asthma exacerbations, and acute and chronic bronchitis [CB]). Exposure to ozone has also been linked to a variety of respiratory effects including hospital admissions and illnesses resulting in school absences. Some studies, including a recent multicity analysis of 95 major U.S. urban areas (Bell et al., 2004), have linked short-term ozone exposures with premature mortality.[2] Welfare effects potentially linked to PM include materials damage and visibility impacts, while ozone can adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. Although methods exist for quantifying the benefits associated with many of these human health and welfare categories, not all can be evaluated at this time because of limitations in methods and/or data. Table 4-1 summarizes the annual monetized health and welfare benefits associated with CAVR for 2015. Table 4-2 lists the full complement of human health and welfare effects associated with PM and ozone and identifies those effects that are quantified for the primary estimate and those that remain unquantified because of current limitations in methods or available data.

Because of schedule and resource limitations, EPA did not conduct a quantitative analysis of benefits from reductions (and potential disbenefits from increases) in ground-level ozone as a result of precursor emissions reductions projected for BART. However, it is unlikely that net benefits resulting from ozone reductions would have a significant impact on any conclusions reached regarding the overall benefits for this rulemaking.

[2]Short-term exposure to ambient ozone has also been linked to premature death. EPA is currently evaluating the epidemiological literature examining the relationship between ozone and premature mortality, sponsoring three independent meta-analyses of the literature. EPA will consider including ozone mortality in primary benefits analyses once a peer-reviewed methodology is available.

Table 4-1. Estimated Monetized Benefits of the Final CAVR

	Total Benefits[a, b] (billions 1999$)		
	Scenario 1	Scenario 2	Scenario 3
Using a 3% discount rate	$2.6 + B	$10.1 + B	$14.3 + B
Using a 7% discount rate	$2.2 + B	$8.6+ B	$12.2 + B

[a] For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. A detailed listing of unquantified health and welfare effects is provided in Table 4-2.

[b] Results reflect the use of two different discount rates: 3 and 7 percent, which are recommended by EPA's *Guidelines for Preparing Economic Analyses* (EPA, 2000b) and OMB Circular A-4 (OMB, 2003). Results are rounded to three significant digits for ease of presentation and computation.

Figure 4-1 illustrates the major steps in the benefits analysis. Given baseline and postcontrol emissions inventories for the emission species expected to affect ambient air quality, we use sophisticated photochemical air quality models to estimate baseline and postcontrol ambient concentrations of ozone and PM and deposition of nitrogen and sulfur for each year. The estimated changes in ambient concentrations are then combined with monitoring data to estimate population-level potential exposures to changes in ambient concentrations for use in estimating health effects. Modeled changes in ambient data are also used to estimate changes in visibility and changes in other air quality statistics that are necessary to estimate welfare effects. Changes in population exposure to ambient air pollution are then input to impact functions[3] to generate changes in the incidence of health effects, or changes in other exposure metrics are input to dose-response functions to generate changes in welfare effects. The resulting effects changes are then assigned monetary values,

[3]The term "impact function" as used here refers to the combination of (a) an effect estimate obtained from the epidemiological literature, (b) the baseline incidence estimate for the health effect of interest in the modeled population, (c) the size of that modeled population, and (d) the change in the ambient air pollution metric of interest. These elements are combined in the impact function to generate estimates of changes in incidence of the health effect. The impact function is distinct from the C-R function, which strictly refers to the estimated equation from the epidemiological study relating incidence of the health effect and ambient pollution. We refer to the specific value of the relative risk or estimated coefficients in the epidemiological study as the "effect estimate." In referencing the functions used to generate changes in incidence of health effects for this RIA, we use the term "impact function" rather than C-R function because "impact function" includes all key input parameters used in the incidence calculation.

Table 4-2. Human Health and Welfare Effects of Pollutants Affected by the Final CAVR

Pollutant/Effect	Quantified and Monetized in Base Estimates[a]	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects—Changes in:
Ozone/Health[b]			Chronic respiratory damage Premature aging of the lungs Nonasthma respiratory emergency room visits Increased exposure to UVb Hospital admissions: respiratory Emergency room visits for asthma Minor restricted-activity days School loss days Premature mortality: short-term exposures[c] Asthma attacks Cardiovascular emergency room visits Acute respiratory symptoms
Ozone/Welfare			Decreased outdoor worker productivity Yields for: – Commercial forests – Fruits and vegetables, and – Other commercial and noncommercial crops Damage to urban ornamental plants Recreational demand from damaged forest aesthetics Ecosystem functions Increased exposure to UVb

(continued)

Table 4-2. Human Health and Welfare Effects of Pollutants Affected by the Final CAVR (continued)

Pollutant/Effect	Quantified and Monetized in Base Estimates[a]	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects—Changes in
PM/Health[d]	Premature mortality based on cohort study estimates[e] Bronchitis: chronic and acute Hospital admissions: respiratory and cardiovascular Emergency room visits for asthma Nonfatal heart attacks (myocardial infarction) Lower and upper respiratory illness Minor restricted-activity days Work loss days Asthma exacerbations (asthmatic population) Respiratory symptoms (asthmatic population) Infant mortality	Premature mortality: short term exposures[f] Subchronic bronchitis cases	Low birth weight Pulmonary function Chronic respiratory diseases other than chronic bronchitis Nonasthma respiratory emergency room visits UVb exposure (+/-)[g]
PM/Welfare	Visibility in Southeastern Class I areas Visibility in western U.S. Class I areas	Visibility in northeastern and Midwestern Class I areas Household soiling	Visibility in residential and non-Class I areas UVb exposure (+/-)[g]

(continued)

Table 4-2. Human Health and Welfare Effects of Pollutants Affected by the Final CAVR (continued)

Pollutant/Effect	Quantified and Monetized in Base Estimates[a]	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects—Changes in:
Nitrogen and Sulfate Deposition/ Welfare			Commercial forests due to acidic sulfate and nitrate deposition
			Commercial freshwater fishing due to acidic deposition
			Recreation in terrestrial ecosystems due to acidic deposition
			Commercial fishing, agriculture, and forests due to nitrogen deposition
			Recreation in estuarine ecosystems due to nitrogen deposition
			Ecosystem functions
			Passive fertilization
SO_2/Health			Hospital admissions for respiratory and cardiac diseases
			Respiratory symptoms in asthmatics
NO_x/Health			Lung irritation
			Lowered resistance to respiratory infection
			Hospital admissions for respiratory and cardiac diseases

(continued)

Table 4-2. Human Health and Welfare Effects of Pollutants Affected by the Final CAVR (continued)

Pollutant/Effect	Quantified and Monetized in Base Estimates[a]	Quantified and/or Monetized Effects in Sensitivity Analyses	Unquantified Effects
Mercury Health[i]			Incidences of neurological disorders Incidences of learning disabilities Incidences in developmental delays Potential cardiovascular effects[h], including: – Altered blood pressure regulation[h] – Increased heart rate variability[h] – Incidences of myocardial infarction[h] Potential reproductive effects[h]
Mercury Deposition Welfare[i]			Impact on birds and mammals (e.g., reproductive effects) Impacts to commercial, subsistence, and recreational fishing

[a] Primary quantified and monetized effects are those included when determining the primary estimate of total monetized benefits of CAVR. See below for a more complete discussion of the benefit estimates.

[b] In addition to primary economic endpoints, a number of biological responses have been associated with ozone health, including increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[c] Recent evidence suggests that short-term exposures to ozone may have a significant effect on daily mortality rates, independent of exposure to PM.

[d] In addition to primary economic endpoints, a number of biological responses have been associated with PM health effects, including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[e] Cohort estimates are designed to examine the effects of long-term exposures to ambient pollution, but relative risk estimates may also incorporate some effects due to short-term exposures (see Kunzli et al. [2001] for a discussion of this issue).

[f] While some of the effects of short-term exposure are likely to be captured by the cohort estimates, there may be additional premature mortality from short-term PM exposure not captured in the cohort estimates included in the primary analysis.

[g] May result in benefits or disbenefits. See Section 5.3.4 for more details.

[h] These are potential effects because the literature is insufficient.

[i] Mercury emission reductions are not anticipated for BART from the EGU source category because of the cap and trade program promulgated for the CAMR (March 2005); however, the geographic location of mercury reductions may change as a result of this rule. EPA believes any such effects for these sources would be minimal. Mercury reductions are expected for the non-EGU source categories. The mercury reductions for BART from the non-EGU source categories is expected to be small in comparison to reductions resulting from the recently promulgated CAIR and CAMR (March 2005).

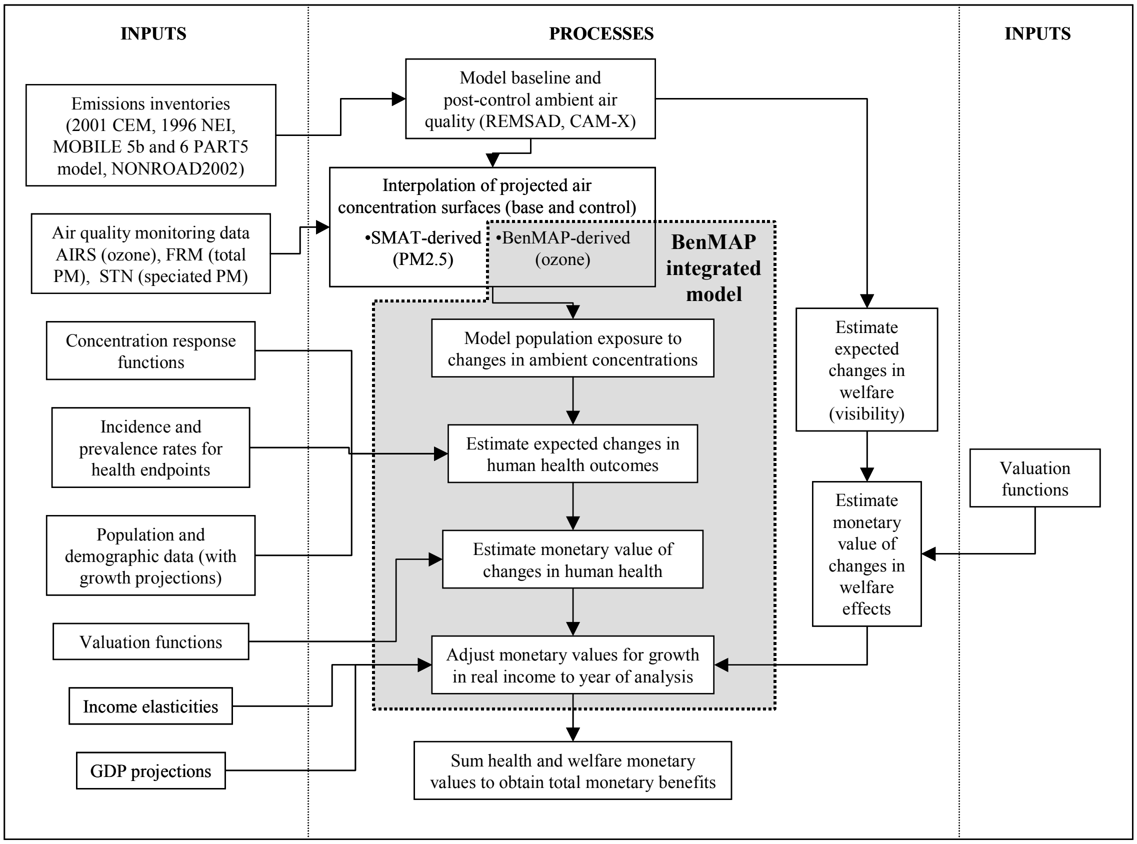

Figure 4-1. Key Steps in Air Quality Modeling-Based Benefits Analysis

taking into account adjustments to values for growth in real income out to the year of analysis (values for health and welfare effects are in general positively related to real income levels). Finally, values for individual health and welfare effects are summed to obtain an estimate of the total monetary value of the changes in emissions.

The benefits discussed in this chapter represent the estimates based on emission changes anticipated for the final CAVR program with one exception. The benefits estimated in this report are slightly understated because Arkansas, New Jersey, and Delaware were included in the CAIR region when IPM modeling was conducted for CAVR. The final CAIR does not include these States; however, EPA has proposed a rule to include New Jersey and Delaware in the CAIR region. Thus, the analysis presented reflects EPA's best estimate of the benefits of CAVR, assuming that New Jersey and Delaware become a part of the CAIR region for $PM_{2.5}$ as well as ozone, but the benefits are slightly understated because of use of modeling that includes Arkansas in the CAIR region for SO_2 and annual NO_x controls. In addition, the recently promulgated CAMR is expected to affect the emissions of SO_2 from EGUs in both the CAIR region and throughout the rest of the United States. The base case for this analysis only included CAIR and not the expected CAMR controls.

EPA is currently developing a comprehensive integrated strategy for characterizing the impact of uncertainty in key elements of the benefits modeling process (e.g., emissions modeling, air quality modeling, health effects incidence estimation, valuation) on the health impact and monetized benefits estimates that are generated. A subset of this effort, which has recently been completed and peer reviewed, was a pilot expert elicitation designed to characterize uncertainty in the estimation of PM-related mortality resulting from both short-term and long-term exposure.[4] The peer review of the pilot expert elicitation was generally favorable. We provide a detailed description of the pilot in Appendix B, along with a summary of results in Section 4.3.

The benefits estimates generated for the final CAVR are subject to a number of assumptions and uncertainties, which are discussed throughout this document. For example, key assumptions underlying the primary estimate for the mortality category include the following:

1) Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been completely established, the weight of the available epidemiological and experimental evidence supports an assumption of causality.

2) All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.

[4]Expert elicitation is a formal, highly structured and well-documented process whereby expert judgments, usually of multiple experts, are obtained (Ayyub, 2002).

3) The C-R function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with the fine particle standard and those that do not meet the standard.

4) The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

In addition to the quantified and monetized benefits summarized above, a number of additional categories are not currently amenable to quantification or valuation. These include reduced acid and particulate deposition damage to cultural monuments and other materials, reduced ozone effects on forested ecosystems, and environmental benefits due to reductions of impacts of acidification in lakes and streams and eutrophication in coastal areas. Additionally, we have not quantified a number of known or suspected health effects linked with PM and ozone for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in forced expiratory volume [FEV1]). As a result, monetized benefits generated for the primary estimate may underestimate the total benefits attributable to the final regulatory scenario.

Because of schedule and resource limitations, EPA did not conduct a quantitative analysis of benefits from reductions (and potential disbenefits from increases) in ground-level ozone as a result of precursor emissions reductions projected for BART. However, it is unlikely that net benefits resulting from ozone reductions would have a significant impact on any conclusions reached regarding the overall benefits for this rulemaking.

Benefits estimates for the final CAVR were generated using BenMAP, a computer program developed by EPA that integrates a number of the modeling elements used in previous RIAs (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates. BenMAP provides estimates of both the mean impacts and the distribution of impacts (more information on BenMAP can be found at http://www.epa.gov/ttn/ecas/ benmodels.html).

In general, this chapter is organized around the steps illustrated in Figure 4-1. In Section 4.1, we provide an overview of the data and methods that were used to quantify and value health and welfare endpoints and discuss how we incorporate uncertainty into our analysis. In Section 4.2, we report the results of the analysis for human health and welfare effects (the overall benefits estimated for the final CAVR are summarized in Table 4-1). Details on the emissions inventory and air modeling are presented in Chapter 3.

4.1 Benefit Analysis—Data and Methods

Given changes in environmental quality (ambient air quality, visibility, nitrogen, and sulfate deposition), the next step is to determine the economic value of those changes. We follow a "damage-function" approach in calculating total benefits of the modeled changes in environmental quality. This approach estimates changes in individual health and welfare endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the individual values. Total benefits are calculated simply as the sum of the values for all nonoverlapping health and welfare endpoints. This imposes no overall preference structure and does not account for potential income or substitution effects (i.e., adding a new endpoint will not reduce the value of changes in other endpoints). The damage-function approach is the standard approach for most cost-benefit analyses of environmental quality programs and has been used in several recent published analyses (Banzhaf et al., 2002; Levy et al., 2001; Levy et al., 1999; Ostro and Chestnut, 1998).

To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued, as is the case for changes in visibility. In other cases, such as for changes in ozone and PM, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

For the purposes of this RIA, the health impacts analysis is limited to those health effects that are directly linked to ambient levels of air pollution and specifically to those linked to PM. There may be other, indirect health impacts associated with implementing emissions controls, such as occupational health impacts for coal miners. These impacts may be positive or negative, but in general, for this set of control alternatives, they are expected to be small relative to the direct air pollution-related impacts.

The welfare impacts analysis is limited to changes in the environment that have a direct impact on human welfare. For this analysis, we are limited by the available data to examine impacts of changes in visibility. We also provide qualitative discussions of the impact of changes in other environmental and ecological effects, for example, changes in deposition of nitrogen and sulfur to terrestrial and aquatic ecosystems, but we are unable to place an economic value on these changes.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure either the health outcomes or their values for this analysis. Thus, similar to Kunzli et al. (2000) and other recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer is the science and art of adapting primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the sociodemographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

4.1.1 Valuation Concepts

In valuing health impacts, we note that reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a fairly small amount for a large population. The appropriate economic measure is willingness to pay[5] (WTP) for changes in risk prior to the regulation (Freeman, 1993).[6] Adoption of WTP as the measure of value implies that the value of environmental quality improvements depends on the individual preferences of the affected population and that the existing distribution of income (ability to pay) is appropriate. For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as the measure of benefits. These cost-of-illness (COI) estimates generally

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[5]For many goods, WTP can be observed by examining actual market transactions. For example, if a gallon of bottled drinking water sells for $1, it can be observed that at least some people are willing to pay $1 for such water. For goods not exchanged in the market, such as most environmental "goods," valuation is not as straightforward. Nevertheless, a value may be inferred from observed behavior, such as sales and prices of products that result in similar effects or risk reductions (e.g., nontoxic cleaners or bike helmets). Alternatively, surveys can be used in an attempt to directly elicit WTP for an environmental improvement.

[6]In general, economists tend to view an individual's WTP for an improvement in environmental quality as the appropriate measure of the value of a risk reduction. An individual's willingness to accept (WTA) compensation for not receiving the improvement is also a valid measure. However, WTP is generally considered to be a more readily available and conservative measure of benefits.

understate the true value of reductions in risk of a health effect, because they do not include the value of avoided pain and suffering from the health effect (Harrington and Portney, 1987; Berger et al., 1987).

One distinction in environmental benefits estimation is between use values and nonuse values. Although no general agreement exists among economists on a precise distinction between the two (see Freeman [1993]), the general nature of the difference is clear. Use values are those aspects of environmental quality that affect an individual's welfare directly. These effects include changes in product prices, quality, and availability; changes in the quality of outdoor recreation and outdoor aesthetics; changes in health or life expectancy; and the costs of actions taken to avoid negative effects of environmental quality changes.

Nonuse values are those for which an individual is willing to pay for reasons that do not relate to the direct use or enjoyment of any environmental benefit but might relate to existence values and bequest values. Nonuse values are not traded, directly or indirectly, in markets. For this reason, measuring nonuse values has proven to be significantly more difficult than measuring use values. The air quality changes produced by CAVR cause changes in both use and nonuse values, but the monetary benefits estimates are almost exclusively for use values.

More frequently than not, the economic benefits from environmental quality changes are not traded in markets, so direct measurement techniques cannot be used. Three main nonmarket valuation methods are used to develop values for endpoints considered in this analysis: stated preference (or contingent valuation [CV]), indirect market (e.g., hedonic wage), and avoided cost methods.

The stated preference or CV method values endpoints by using carefully structured surveys to ask a sample of people what amount of compensation is equivalent to a given change in environmental quality. There is an extensive scientific literature and body of practice on both the theory and technique of stated preference-based valuation. Well-designed and well-executed stated preference studies are valid for estimating the benefits of air quality regulations.[7] Stated preference valuation studies form the basis for valuing a number of health and welfare endpoints, including the value of mortality risk reductions, CB risk reductions, minor illness risk reductions, and visibility improvements.

Indirect market methods can also be used to infer the benefits of pollution reduction. The most important application of this technique for our analysis is the calculation of the value of a statistical life (VSL) for use in estimating benefits from mortality risk reductions. No market exists where changes in the probability of death are directly exchanged. However, people make decisions about occupation, precautionary behavior, and other activities associated with changes in the risk of death. By examining these risk changes and the other characteristics of people's choices, it is possible to infer information about the monetary values associated with changes in mortality risk (see Section 4.1.5).

Avoided cost methods are ways to estimate the costs of pollution by using the expenditures made necessary by pollution damage. For example, if buildings must be cleaned or painted more frequently as levels of PM increase, then the appropriately calculated increment of these costs is a reasonable lower-bound estimate (under most conditions) of true economic benefits when PM levels are reduced. Avoided costs methods are also used to estimate some of the health-related benefits related to morbidity, such as hospital admissions (see Section 4.1.5).

4.1.2 Growth in WTP Reflecting National Income Growth Over Time

Our analysis accounts for expected growth in real income over time. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real incomes increase. There is substantial empirical evidence that the income elasticity[8] of WTP for health risk reductions is positive, although there is uncertainty about its exact value.

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[7]Concerns about the reliability of value estimates from CV studies arose because research has shown that bias can be introduced easily into these studies if they are not carefully conducted. Accurately measuring WTP for avoided health and welfare losses depends on the reliability and validity of the data collected. There are several issues to consider when evaluating study quality, including but not limited to (1) whether the sample estimates of WTP are representative of the population WTP; (2) whether the good to be valued is comprehended and accepted by the respondent; (3) whether the WTP elicitation format is designed to minimize strategic responses; (4) whether WTP is sensitive to respondent familiarity with the good, to the size of the change in the good, and to income; (5) whether the estimates of WTP are broadly consistent with other estimates of WTP for similar goods; and (6) the extent to which WTP responses are consistent with established economic principles.

[8]Income elasticity is a common economic measure equal to the percentage change in WTP for a 1 percent change in income.

Thus, as real income increases, the WTP for environmental improvements also increases. Although many analyses assume that the income elasticity of WTP is unit elastic (i.e., a 10 percent higher real income level implies a 10 percent higher WTP to reduce risk changes), empirical evidence suggests that income elasticity is substantially less than one and thus relatively inelastic. As real income rises, the WTP value also rises but at a slower rate than real income.

The effects of real income changes on WTP estimates can influence benefits estimates in two different ways: through real income growth between the year a WTP study was conducted and the year for which benefits are estimated, and through differences in income between study populations and the affected populations at a particular time. Empirical evidence of the effect of real income on WTP gathered to date is based on studies examining the former. The Environmental Economics Advisory Committee (EEAC) of the SAB advised EPA to adjust WTP for increases in real income over time but not to adjust WTP to account for cross-sectional income differences "because of the sensitivity of making such distinctions, and because of insufficient evidence available at present" (EPA-SAB-EEAC-00-013, 2000). A recent advisory by another committee associated with the SAB, the Advisory Council on Clean Air Compliance Analysis, has provided conflicting advice. While agreeing with "the general principle that the willingness to pay to reduce mortality risks is likely to increase with growth in real income. The same increase should be assumed for the WTP for serious nonfatal health effects (EPA-SAB-COUNCIL-ADV-04-004, p. 52)," they note that "given the limitations and uncertainties in the available empirical evidence, the Council does not support the use of the proposed adjustments for aggregate income growth as part of the primary analysis" (EPA-SAB-COUNCIL-ADV-04-004, p. 53). Until these conflicting advisories have been reconciled, EPA will continue to adjust valuation estimates to reflect income growth using the methods described below.

Based on a review of the available income elasticity literature, we adjusted the valuation of human health benefits upward to account for projected growth in real U.S. income. Faced with a dearth of estimates of income elasticities derived from time-series studies, we applied estimates derived from cross-sectional studies in our analysis. Details of the procedure can be found in Kleckner and Neumann (1999). An abbreviated description of the procedure we used to account for WTP for real income growth between 1990 and 2015 is presented below.

Reported income elasticities suggest that the severity of a health effect is a primary determinant of the strength of the relationship between changes in real income and WTP. As such, we use different elasticity estimates to adjust the WTP for minor health effects, severe and chronic health effects, and premature mortality. Note that because of the variety of empirical sources used in deriving the income elasticities, there may appear to be inconsistencies in the magnitudes of the income elasticities relative to the severity of the effects (a priori one might expect that more severe outcomes would show less income elasticity of WTP). We have not imposed any additional restrictions on the empirical estimates of income elasticity. We also expect that the WTP for improved visibility in Class I areas would increase with growth in real income. The relative magnitude of the income elasticity of WTP for visibility compared with those for health effects suggests that visibility is not as much of a necessity as health; thus, WTP is more elastic with respect to income. The elasticity values used to adjust estimates of benefits in 2015 are presented in Table 4-3.

Table 4-3. Elasticity Values Used to Account for Projected Real Income Growth[a]

Benefit Category	Central Elasticity Estimate
Minor Health Effect	0.14
Severe and Chronic Health Effects	0.45
Premature Mortality	0.40
Visibility	0.90

[a] Derivation of estimates can be found in Kleckner and Neumann (1999) and Chestnut (1997). COI estimates are assigned an adjustment factor of 1.0.

In addition to elasticity estimates, projections of real gross domestic product (GDP) and populations from 1990 to 2015 are needed to adjust benefits to reflect real per capita income growth. For consistency with the emissions and benefits modeling, we used national population estimates for the years 1990 to 1999 based on U.S. Census Bureau estimates (Hollman et al., 2000). These population estimates are based on application of a cohort-component model applied to 1990 U.S. Census data projections (U.S. Bureau of Census, 2000). For the years between 2000 and 2015, we applied growth rates based on the U.S. Census Bureau projections to the U.S. Census estimate of national population in 2000. We used projections of real GDP provided in Kleckner and Neumann (1999) for the years 1990 to 2010.[9] We used projections of real GDP (in chained 1996 dollars) provided by Standard and Poor's (2000) for the year 2015.[10]

Using the method outlined in Kleckner and Neumann (1999) and the population and income data described above, we calculated WTP adjustment factors for each of the elasticity estimates listed in Table 4-4. Benefits for each of the categories (minor health effects, severe and chronic health effects, premature mortality, and visibility) are adjusted by multiplying the unadjusted benefits by the appropriate adjustment factor. Table 4-4 lists the estimated adjustment factors. Note that, for premature mortality, we applied the income adjustment factor to the present discounted value of the stream of avoided mortalities occurring over the lag period. Also note that because of a lack of data on the dependence of COI and income, and a lack of data on projected growth in average wages, no adjustments are made to benefits based on the COI approach or to work-loss days and worker productivity. This assumption leads us to underpredict benefits in future years because it is likely that increases in real U.S. income would also result in increased COI (due, for example, to increases in wages paid to medical workers) and increased cost of work-loss days and lost worker productivity (reflecting that if worker incomes are higher, the losses resulting from reduced worker production would also be higher).

Table 4-4. Adjustment Factors Used to Account for Projected Real Income Growth[a]

Benefit Category	Adjustment Factor
Minor Health Effect	1.073
Severe and Chronic Health Effects	1.254
Premature Mortality	1.222
Visibility	1.581

[a] Based on elasticity values reported in Table 4-3, U.S. Census population projections, and projections of real GDP per capita.

[9] U.S. Bureau of Economic Analysis, Table 2A (1992$) (available at http://www.bea.doc.gov/bea/dn/0897nip2/tab2a.htm.) and U.S. Bureau of Economic Analysis, Economics and Budget Outlook. Note that projections for 2007 to 2010 are based on average GDP growth rates between 1999 and 2007.

[10] In previous analyses, we used the Standard and Poor's projections of GDP directly. This led to an apparent discontinuity in the adjustment factors between 2010 and 2011. We refined the method by applying the relative growth rates for GDP derived from the Standard and Poor's projections to the 2010 projected GDP based on the Bureau of Economic Analysis projections.

4.1.3 Methods for Describing Uncertainty

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. As outlined both in this and preceding chapters, many inputs were used to derive the final estimate of benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological health effect estimates, estimates of values (both from WTP and COI studies), population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain and, depending on its role in the benefits analysis, may have a disproportionately large impact on final estimates of total benefits. For example, emissions estimates are used in the first stage of the analysis. As such, any uncertainty in emissions estimates will be propagated through the entire analysis. When compounded with uncertainty in later stages, small uncertainties in emission levels can lead to large impacts on total benefits.

Some key sources of uncertainty in each stage of the benefits analysis are the following:

- gaps in scientific data and inquiry;
- variability in estimated relationships, such as epidemiological effect estimates, introduced through differences in study design and statistical modeling;
- errors in measurement and projection for variables such as population growth rates;
- errors due to misspecification of model structures, including the use of surrogate variables, such as using PM_{10} when $PM_{2.5}$ is not available, excluded variables, and simplification of complex functions; and
- biases due to omissions or other research limitations.

Some of the key uncertainties in the benefits analysis are presented in Table 4-5.

The NRC report on EPA's benefits analysis methodology highlighted the need for EPA to conduct rigorous quantitative analysis of uncertainty in its benefits estimates. In response to these comments, EPA has initiated the development of a comprehensive methodology for characterizing the aggregate impact of uncertainty in key modeling elements on both health incidence and benefits estimates. For this analysis of the final

Table 4-5. Primary Sources of Uncertainty in the Benefits Analysis

1. Uncertainties Associated with Impact Functions

– The value of the ozone or PM effect estimate in each impact function.
– Application of a single impact function to pollutant changes and populations in all locations.
– Similarity of future-year impact functions to current impact functions.
– Correct functional form of each impact function.
– Extrapolation of effect estimates beyond the range of ozone or PM concentrations observed in the source epidemiological study.
– Application of impact functions only to those subpopulations matching the original study population.

2. Uncertainties Associated with Ozone and PM Concentrations

– Responsiveness of the models to changes in precursor emissions resulting from the control policy.
– Projections of future levels of precursor emissions, especially ammonia and crustal materials.
– Model chemistry for the formation of ambient nitrate concentrations.
– Lack of ozone monitors in rural areas requires extrapolation of observed ozone data from urban to rural areas.
– Use of separate air quality models for ozone and PM does not allow for a fully integrated analysis of pollutants and their interactions.
– Full ozone season air quality distributions are extrapolated from a limited number of simulation days.

3. Uncertainties Associated with PM Mortality Risk

– Limited scientific literature supporting a direct biological mechanism for observed epidemiological evidence.
– Direct causal agents within the complex mixture of PM have not been identified.
– The extent to which adverse health effects are associated with low-level exposures that occur many times in the year versus peak exposures.
– The extent to which effects reported in the long-term exposure studies are associated with historically higher levels of PM rather than the levels occurring during the period of study.
– Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.

4. Uncertainties Associated with Possible Lagged Effects

– The portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels that would occur in a single year is uncertain as well as the portion that might occur in subsequent years.

5. Uncertainties Associated with Baseline Incidence Rates

– Some baseline incidence rates are not location specific (e.g., those taken from studies) and therefore may not accurately represent the actual location-specific rates.
– Current baseline incidence rates may not approximate well baseline incidence rates in 2015.
– Projected population and demographics may not represent well future-year population and demographics.

6. Uncertainties Associated with Economic Valuation

– Unit dollar values associated with health and welfare endpoints are only estimates of mean WTP and therefore have uncertainty surrounding them.
– Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates because of differences in income or other factors.

7. Uncertainties Associated with Aggregation of Monetized Benefits

– Health and welfare benefits estimates are limited to the available impact functions. Thus, unquantified or unmonetized benefits are not included.

CAVR, EPA has developed a limited probabilistic simulation approach based on Monte Carlo methods to propagate the impact of a limited set of sources of uncertainty through the modeling framework. Issues such as correlation between input parameters and the identification of reasonable upper and lower bounds for input distributions characterizing uncertainty in additional model elements will be addressed in future versions of the uncertainty framework.

One component of EPA's uncertainty analysis methodology that is partially reflected in the CAVR analysis is our work using the results of an expert elicitation to characterize uncertainty in the effect estimates used to estimate premature mortality resulting from both short-term and long-term exposures to PM. This expert elicitation was aimed at evaluating uncertainty in both the form of the mortality impact function (e.g., threshold versus linear models) and the fit of a specific model to the data (e.g., confidence bounds for specific percentiles of the mortality effect estimates). Additional issues, such as the ability of long-term cohort studies to capture premature mortality resulting from short-term peak PM exposures, were also addressed in the expert elicitation. In collaboration with OMB, EPA completed a pilot expert elicitation that is used in the ancillary uncertainty analysis for CAVR (as discussed in Section 4.3). Based on our experience during the pilot, EPA plans to conduct a full-scale expert elicitation in 2005 that will provide a more robust characterization of the uncertainty in the premature mortality function.

For the final CAVR, EPA addressed key sources of uncertainty through Monte Carlo propagation of uncertainty in the C-R functions and economic valuation functions and through a series of sensitivity analyses examining the impact of alternate assumptions on the benefits estimates that are generated. It should be noted that the Monte Carlo-generated distributions of benefits reflect only some of the uncertainties in the input parameters. Uncertainties associated with emissions, air quality modeling, populations, and baseline health effect incidence rates are not represented in the distributions of benefits for CAVR.

Our point estimate of total benefits is uncertain because of the uncertainty in model elements discussed above (see Table 4-5). Uncertainty about specific aspects of the health and welfare estimation models is discussed in greater detail in the following sections. The total benefits estimate may understate or overstate actual benefits of the rule.

In considering the monetized benefits estimates, the reader should remain aware of the many limitations of conducting the analyses mentioned throughout this RIA. One significant limitation of both the health and welfare benefits analyses is the inability to quantify many of the effects listed in Table 4-1. As previously discussed, ozone benefits are anticipated for this rule but were not estimates for this analysis. For many health and welfare effects, such as changes in ecosystem functions and PM-related materials damage, reliable impact functions and/or valuation functions are not currently available. In general, if it were possible to monetize these benefit categories, the benefits estimates presented in this analysis would increase, although the magnitude of such an increase is highly uncertain. Unquantified benefits are qualitatively discussed in the health and welfare effects sections. In addition to unquantified benefits, there may also be environmental costs (disbenefits) that we are unable to quantify. These endpoints are qualitatively discussed in the health and welfare effects sections as well. The net effect of excluding benefit and disbenefit categories from the estimate of total benefits depends on the relative magnitude of the effects.

Although we are not currently able to estimate the magnitude of these unquantified and unmonetized benefits, specific categories merit further discussion. EPA believes there is considerable value to the public for the benefit categories that could not be monetized. With regard to unmonetized PM-related health benefit categories listed in Table 4-2, we believe these benefits may be small relative to those categories we were able to quantify and monetize.

In addition to unquantified and unmonetized health benefit categories, Table 4-2 shows a number of welfare benefit categories that are omitted from the monetized benefit estimates for this rule. Only a subset of the expected visibility benefits—those for Class I areas in the southeastern and southwestern United States—are included in the monetary benefits estimates we project for this rule. We know that additional visibility benefits will occur in other parks in the country and in urban areas. Those benefits are described in Chapter 3, and an analysis of the potential dollar value of the benefits is included in Appendix F of this report. We believe the benefits associated with these nonhealth benefit categories are likely significant. For example, we are able to quantify significant visibility improvements in Class I areas in the Northeast, Midwest, and Northwest but are unable at present to place a monetary value on these improvements. Similarly, we anticipate improvement in visibility in residential areas within the CAVR region for which we are currently unable to monetize benefits. For the Class I areas in the southeastern and southwestern United States for the Scenario 2 alternative, we estimate annual benefits of $242 million beginning in 2015 for visibility improvements. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial. Annual visibility benefits are estimated to be approximately $84 million and $416 million for Scenarios 1 and 3, respectively.

We conduct supplemental analyses related to visibility and household cleaning costs later in this chapter. Based on these analyses, expanded coverage of these benefit categories could increase total benefits by over $153 million for Scenario 2. (See Appendix E for more details.)

In a recent study, Resources for the Future (RFF) estimates total benefits (i.e., the sum of use and nonuse values) of natural resource improvements for the Adirondacks resulting from a program that would reduce acidification in 40 percent of the lakes in the Adirondacks of concern for acidification (Banzhaf et al., 2004). Although the study requires further evaluation, the RFF study does suggest that the benefits of acid deposition reductions for CAVR could be substantial in terms of the total monetized value for ecological endpoints.

4.1.4 Demographic Projections

Quantified and monetized human health impacts depend on the demographic characteristics of the population, including age, location, and income. We use projections based on economic forecasting models developed by Woods and Poole, Inc. The Woods and Poole (WP) database contains county-level projections of population by age, sex, and race out to 2025. Projections in each county are determined simultaneously with every other county in the United States to take into account patterns of economic growth and migration. The sum of growth in county-level populations is constrained to equal a previously determined national population growth, based on Bureau of Census estimates (Hollman et al., 2000). According to WP, linking county-level growth projections together and constraining to a national-level total growth avoids potential errors introduced by forecasting each county independently. County projections are developed in a four-stage process. First, national-level variables such as income, employment, and populations are forecasted. Second, employment projections are made for 172 economic areas defined by the Bureau of Economic Analysis, using an "export-base" approach, which relies on linking industrial-sector production of nonlocally consumed production items, such as outputs from mining, agriculture, and manufacturing with the national economy. The export-based approach requires estimation of demand equations or calculation of historical growth rates for output and employment by sector. Third, population is projected for each economic area based on net migration rates derived from employment opportunities and following a cohort-component method based on fertility and mortality in each area. Fourth, employment and population projections are repeated for counties, using the economic region totals as bounds. The age, sex, and race distributions for each region or county are determined by aging the population by single year of age by sex and race for each year through 2015 based on historical rates of mortality, fertility, and migration.

The WP projections of county-level population are based on historical population data from 1969 through 1999 and do not include the 2000 Census results. Given the availability of detailed 2000 Census data, we constructed adjusted county-level population projections for each future year using a two-stage process. First, we constructed ratios of the projected WP populations in a future year to the projected WP population in 2000 for each future year by age, sex, and race. Second, we multiplied the block-level 2000 Census population data by the appropriate age-, sex-, and race-specific WP ratio for the county containing the census block for each future year. This results in a set of future population projections that is consistent with the most recent detailed Census data.

As noted above, values for environmental quality improvements are expected to increase with growth in real per capita income. Accounting for real income growth over time requires projections of both real GDP and total U.S. populations. For consistency with the emissions and benefits modeling, we used national population estimates based on the U.S. Census Bureau projections.

4.1.5 Health Benefits Assessment Methods

The largest monetized benefits of reducing ambient concentrations of PM are attributable to reductions in health risks associated with air pollution. EPA's Criteria Document for PM lists numerous health effects known to be linked to ambient concentrations of PM (EPA, 2004). As illustrated in Figure 4-1, quantification of health impacts requires several inputs, including epidemiological effect estimates (concentration-response functions), baseline incidence and prevalence rates, potentially affected populations, and estimates of changes in ambient concentrations of air pollution. Previous sections have described the population and air quality inputs. This section describes the effect estimates and baseline incidence and prevalence inputs and the methods used to quantify and monetize changes in the expected number of incidences of various health effects.

4.1.5.1 Selecting Health Endpoints and Epidemiological Effect Estimates

The PM health effects we quantified include premature mortality, nonfatal heart attacks, CB, acute bronchitis, upper and lower respiratory symptoms, asthma exacerbations, and days of work lost. We relied on the published scientific literature to ascertain the relationship between potential PM exposure (measured by ambient concentrations) and adverse human health effects. We evaluated studies using the selection criteria summarized in Table 4-6. These criteria include consideration of whether the study was peer reviewed, the match between the pollutant studied and the pollutant of interest, the study design and location, and characteristics of the study population, among other considerations. The selection of C-R functions for the benefits analysis is guided by the goal of achieving a balance between comprehensiveness and scientific defensibility.

Some health effects are excluded from this analysis for three reasons: the possibility of double-counting (such as hospital admissions for specific respiratory diseases), uncertainties in applying effect relationships based on clinical studies to the affected population, or a lack of an established relationship between the health effect and pollutant in the published epidemiological literature. An improvement in ambient PM air quality may reduce the number of incidences within each unquantified effect category that the U.S. population would experience. Although these health effects are believed to be PM induced, effect estimates are not available for quantifying the benefits associated with reducing these effects. The inability to quantify these effects lends a downward bias to the monetized benefits presented in this analysis.

In general, the use of results from more than a single study can provide a more robust estimate of the relationship between a pollutant and a given health effect. However, there are often differences between studies examining the same endpoint, making it difficult to pool the results in a consistent manner. For example, studies may examine different pollutants or different age groups. For this reason, we consider very carefully the set of studies available examining each endpoint and select a consistent subset that provides a good balance of population coverage and match with the pollutant of interest. In many cases, either because of a lack of multiple studies, consistency problems, or clear superiority in the quality or comprehensiveness of one study over others, a single published study is selected as the basis of the effect estimate.

When several effect estimates for a pollutant and a given health endpoint have been selected, they are quantitatively combined or pooled to derive a more robust estimate of the relationship. The BenMAP User's Manual provides details of the procedures used to combine multiple impact functions (Abt Associates, 2003). In general, we used fixed or random effects models to pool estimates from different studies of the same endpoint. Fixed effects pooling simply weights each study's estimate by the inverse variance, giving more weight to studies with greater statistical power (lower variance). Random effects pooling accounts for both within-study variance and between-study variability, due, for example, to

Table 4-6. Summary of Considerations Used in Selecting C-R Functions

Consideration	Comments
Peer-Reviewed Research	Peer-reviewed research is preferred to research that has not undergone the peer-review process.
Study Type	Among studies that consider chronic exposure (e.g., over a year or longer), prospective cohort studies are preferred over cross-sectional studies because they control for important individual-level confounding variables that cannot be controlled for in cross-sectional studies.
Study Period	Studies examining a relatively longer period of time (and therefore having more data) are preferred, because they have greater statistical power to detect effects. More recent studies are also preferred because of possible changes in pollution mixes, medical care, and lifestyle over time. However, when there are only a few studies available, studies from all years will be included.
Population Attributes	The most technically appropriate measures of benefits would be based on impact functions that cover the entire sensitive population but allow for heterogeneity across age or other relevant demographic factors. In the absence of effect estimates specific to age, sex, preexisting condition status, or other relevant factors, it may be appropriate to select effect estimates that cover the broadest population to match with the desired outcome of the analysis, which is total national-level health impacts.
Study Size	Studies examining a relatively large sample are preferred because they generally have more power to detect small magnitude effects. A large sample can be obtained in several ways, either through a large population or through repeated observations on a smaller population (e.g., through a symptom diary recorded for a panel of asthmatic children).
Study Location	U.S. studies are more desirable than non-U.S. studies because of potential differences in pollution characteristics, exposure patterns, medical care system, population behavior, and lifestyle.
Pollutants Included in Model	When modeling the effects of ozone and PM (or other pollutant combinations) jointly, it is important to use properly specified impact functions that include both pollutants. Using single-pollutant models in cases where both pollutants are expected to affect a health outcome can lead to double-counting when pollutants are correlated.
Measure of PM	For this analysis, impact functions based on $PM_{2.5}$ are preferred to PM_{10} because CAVR will regulate emissions of $PM_{2.5}$ precursors, and air quality modeling was conducted for this size fraction of PM. Where $PM_{2.5}$ functions are not available, PM_{10} functions are used as surrogates, recognizing that there will be potential downward (upward) biases if the fine fraction of PM_{10} is more (less) toxic than the coarse fraction.
Economically Valuable Health Effects	Some health effects, such as forced expiratory volume and other technical measurements of lung function, are difficult to value in monetary terms. These health effects are not quantified in this analysis.
Nonoverlapping Endpoints	Although the benefits associated with each individual health endpoint may be analyzed separately, care must be exercised in selecting health endpoints to include in the overall benefits analysis because of the possibility of double-counting of benefits.

differences in population susceptibility. We used the fixed effects model as our null hypothesis and then determined whether the data suggest that we should reject this null hypothesis, in which case we would use the random effects model.[11] Pooled impact functions are used to estimate hospital admissions, lower respiratory symptoms, and asthma exacerbations. For more details on methods used to pool incidence estimates, see the Benefits TSD for the nonroad diesel rulemaking (Abt Associates, 2003).

Effect estimates for a pollutant and a given health endpoint were applied consistently across all locations nationwide. This applies to both impact functions defined by a single effect estimate and those defined by a pooling of multiple effect estimates. Although the effect estimate may, in fact, vary from one location to another (e.g., because of differences in population susceptibilities or differences in the composition of PM), location-specific effect estimates are generally not available.

The specific studies from which effect estimates for the primary analysis are drawn are included in Table 4-7.

Premature Mortality. Both long- and short-term exposures to ambient levels of air pollution have been associated with increased risk of premature mortality. The size of the mortality risk estimates from epidemiological studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make mortality risk reduction the most significant health endpoint quantified in this analysis.

Although a number of uncertainties remain to be addressed by continued research (NRC, 1998), a substantial body of published scientific literature documents the correlation between elevated PM concentrations and increased mortality rates. Time-series methods relate short-term (often day-to-day) changes in PM concentrations and changes in daily mortality rates up to several days after a period of elevated PM concentrations. Cohort methods examine the potential relationship between community-level PM exposures over multiple years (i.e., long-term exposures) and community-level annual mortality rates. Researchers have found statistically significant associations between PM and premature mortality using both types of studies. In general, the risk estimates based on the cohort studies are larger than those derived from time-series studies. Cohort analyses are thought to

[11]In this analysis, the fixed effects model assumes that there is only one pollutant coefficient for the entire modeled area. The random effects model assumes that studies conducted in different locations are estimating different parameters; therefore, there may be a number of different underlying pollutant coefficients.

Table 4-7. Endpoints and Studies Used to Calculate Total Monetized Health Benefits

Endpoint	Pollutant	Study	Study Population
Premature Mortality			
Premature mortality—cohort study, all-cause	$PM_{2.5}$ (annual mean)	Pope et al. (2002)	>29 years
Premature mortality—all-cause	$PM_{2.5}$ (annual mean)	Woodruff et al. (1997)	Infant (<1 year)
Chronic Illness			
Chronic bronchitis	$PM_{2.5}$ (annual mean)	Abbey et al. (1995)	>26 years
Nonfatal heart attacks	$PM_{2.5}$ (daily)	Peters et al. (2001)	Adults
Hospital Admissions			
Respiratory	$PM_{2.5}$ (daily)	Pooled estimate: Moolgavkar (2003)—ICD 490-496 (COPD) Ito (2003)—ICD 490-496 (COPD)	>64 years
	$PM_{2.5}$ (daily)	Moolgavkar (2000)—ICD 490-496 (COPD)	20–64 years
	$PM_{2.5}$ (daily)	Ito (2003)—ICD 480-486 (pneumonia)	>64 years
	$PM_{2.5}$ (daily)	Sheppard (2003)—ICD 493 (asthma)	<65 years
Cardiovascular	$PM_{2.5}$ (daily)	Pooled estimate: Moolgavkar (2003)—ICD 390-429 (all cardiovascular) Ito (2003)—ICD 410-414, 427-428 (ischemic heart disease, dysrhythmia, heart failure)	>64 years
	$PM_{2.5}$ (daily)	Moolgavkar (2000)—ICD 390-429 (all cardiovascular)	20–64 years
Asthma-related ER visits	$PM_{2.5}$ (daily)	Norris et al. (1999)	0–18 years

(continued)

Table 4-7. Endpoints and Studies Used to Calculate Total Monetized Health Benefits (continued)

Endpoint	Pollutant	Study	Study Population
Other Health Endpoints			
Acute bronchitis	$PM_{2.5}$ (annual mean)	Dockery et al. (1996)	8–12 years
Upper respiratory symptoms	PM_{10} (daily)	Pope et al. (1991)	Asthmatics, 9–11 years
Lower respiratory symptoms	$PM_{2.5}$ (daily)	Schwartz and Neas (2000)	7–14 years
Asthma exacerbations	$PM_{2.5}$ (daily)	Pooled estimate: Ostro et al. (2001) (cough, wheeze and shortness of breath) Vedal et al. (1998) (cough)	6–18 years[a]
Work loss days	$PM_{2.5}$ (daily)	Ostro (1987)	18–65 years
MRADs	$PM_{2.5}$ (daily)	Ostro and Rothschild (1989)	18–65 years

[a] The original study populations were 8 to 13 for the Ostro et al. (2001) study and 6 to 13 for the Vedal et al. (1998) study. Based on advice from the SAB-HES, we extended the applied population to 6 to 18, reflecting the common biological basis for the effect in children in the broader age group.

better capture the full public health impact of exposure to air pollution over time, because they capture the effects of long-term exposures and possibly some component of short-term exposures (Kunzli et al., 2001; NRC, 2002). This section discusses some of the issues surrounding the estimation of premature mortality.

Over a dozen studies have found significant associations between various measures of long-term exposure to PM and elevated rates of annual mortality, beginning with Lave and Seskin (1977). Most of the published studies found positive (but not always statistically significant) associations with available PM indices such as total suspended particles (TSP). However, exploration of alternative model specifications sometimes raised questions about causal relationships (e.g., Lipfert, Morris, and Wyzga [1989]). These early "cross-sectional" studies (e.g., Lave and Seskin [1977]; Ozkaynak and Thurston [1987]) were criticized for a number of methodological limitations, particularly for inadequate control at the individual level for variables that are potentially important in causing mortality, such as wealth, smoking, and diet. More recently, several studies have been published that use improved approaches and appear to be consistent with the earlier body of literature. These new "prospective cohort" studies reflect a significant improvement over the earlier work because they include individual-level information with respect to health status and residence. The most extensive analyses have been based on data from two prospective cohort groups, often referred to as the Harvard "Six-Cities Study" (Dockery et al., 1993) and the "American Cancer Society or ACS study" (Pope et al., 1995); these studies have found consistent relationships between fine particle indicators and premature mortality across multiple locations in the United States. A third major data set comes from the California-based 7th Day Adventist Study (e.g., Abbey et al. [1999]), which reported associations between long-term PM exposure and mortality in men. Results from this cohort, however, have been inconsistent, and the air quality results are not geographically representative of most of the United States. More recently, a cohort of adult male veterans diagnosed with hypertension has been examined (Lipfert et al., 2000). The characteristics of this group differ from the cohorts in the Six-Cities, ACS, and 7th Day Adventist studies with respect to income, race, health status, and smoking status. Unlike previous long-term analyses, this study found some associations between mortality and ozone but found inconsistent results for PM indicators. Because of the selective nature of the population in the veteran's cohort, we have chosen not to include any effect estimates from the Lipfert et al. (2000) study in our benefits assessment.[12]

Given their consistent results and broad geographic coverage, the Six-Cities and ACS data have been particularly important in benefits analyses. The credibility of these two studies is further enhanced by the fact that they were subject to extensive reexamination and reanalysis by an independent team of scientific experts commissioned by HEI (Krewski et al., 2000). The final results of the reanalysis were then independently peer reviewed by a Special Panel of the HEI Health Review Committee. The results of these reanalyses

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[12]EPA recognizes that the ACS cohort also is not representative of the demographic mix in the general population. The ACS cohort is almost entirely white and has higher income and education levels relative to the general population. EPA's approach to this problem is to match populations based on the potential for demographic characteristics to modify the effect of air pollution on mortality risk. Thus, for the various ACS-based models, we are careful to apply the effect estimate only to ages matching those in the original studies, because age has a potentially large modifying impact on the effect estimate, especially when younger individuals are excluded from the study population. For the Lipfert analysis, the applied population should be limited to that matching the sample used in the analysis. This sample was all male, veterans, and diagnosed hypertensive. There are also a number of differences between the composition of the sample and the general population, including a higher percentage of African Americans (35 percent) and a much higher percentage of smokers (81 percent former smokers, 57 percent current smokers) than the general population (12 percent African American, 24 percent current smokers).

confirmed and expanded those of the original investigators. This intensive independent reanalysis effort was occasioned both by the importance of the original findings and concerns that the underlying individual health effects information has never been made publicly available.

While the HEI reexamination lends credibility to the original studies, it also highlights sensitivities concerning the relative impact of various pollutants, the potential role of education in mediating the association between pollution and mortality, and the influence of spatial correlation modeling. Further confirmation and extension of the overall findings using more recent air quality and a longer follow-up period for the ACS cohort was recently published (Pope et al., 2002).

In developing and improving the methods for estimating and valuing the potential reductions in mortality risk over the years, EPA consulted with the SAB-HES. That panel recommended using long-term prospective cohort studies in estimating mortality risk reduction (EPA-SAB-COUNCIL-ADV-99-005, 1999). This recommendation has been confirmed by a recent report from the National Research Council, which stated that "it is essential to use the cohort studies in benefits analysis to capture all important effects from air pollution exposure" (NRC, 2002, p. 108). More specifically, the SAB recommended emphasis on the ACS study because it includes a much larger sample size and longer exposure interval and covers more locations (e.g., 50 cities compared to the Six-Cities Study) than other studies of its kind. As explained in the regulatory impact analysis for the Heavy-Duty Engine/Diesel Fuel rule (EPA, 2000d), more recent EPA benefits analyses have relied on an improved specification of the ACS cohort data that was developed in the HEI reanalysis (Krewski et al., 2000). The latest reanalysis of the ACS cohort data (Pope et al., 2002) provides additional refinements to the analysis of PM-related mortality by a) extending the follow-up period for the ACS study subjects to 16 years, which triples the size of the mortality data set; b) substantially increasing exposure data, including consideration for cohort exposure to $PM_{2.5}$ following implementation of the $PM_{2.5}$ standard in 1999; c) controlling for a variety of personal risk factors including occupational exposure and diet; and d) using advanced statistical methods to evaluate specific issues that can adversely affect risk estimates including the possibility of spatial autocorrelation of survival times in communities located near each other. Because of these refinements, the SAB-HES recommends using the Pope et al. (2002) study as the basis for the primary mortality estimate for adults and suggests that alternate estimates of mortality generated using other cohort and time-series studies could be included as part of the sensitivity analysis (SAB-HES, 2004).

The SAB-HES also recommended using the estimated relative risks from the Pope et al. (2002) study based on the average exposure to $PM_{2.5}$, measured by the average of two $PM_{2.5}$ measurements, over the periods 1979–1983 and 1999–2000. In addition to relative risks for all-cause mortality, the Pope et al. (2002) study provides relative risks for cardiopulmonary, lung cancer, and all-other cause mortality. Because of concerns regarding the statistical reliability of the all-other cause mortality relative risk estimates, we calculated mortality impacts for the primary analysis based on the all-cause relative risk. However, we provide separate estimates of cardiopulmonary and lung cancer deaths to show how these important causes of death are affected by reductions in $PM_{2.5}$.

Recently published studies have strengthened the case for an association between PM exposure and respiratory inflamation and infection leading to premature mortality in children under 5 years of age. Specifically, the SAB-HES noted the release of the WHO Global Burden of Disease Study focusing on ambient air, which cites several recently published time-series studies relating daily PM exposure to mortality in children (SAB-HES, 2003). The SAB-HES also cites the study by Belanger et al. (2003) as corroborating findings linking PM exposure to increased respiratory inflamation and infections in children. Recently, a study by Chay and Greenstone (2003) found that reductions in TSP caused by the recession of 1981–1982 were related to reductions in infant mortality at the county level. With regard to the cohort study conducted by Woodruff et al. (1997), the SAB-HES notes several strengths of the study, including the use of a larger cohort drawn from a large number of metropolitan areas and efforts to control for a variety of individual risk factors in infants (e.g., maternal educational level, maternal ethnicity, parental marital status, and maternal smoking status). Based on these findings, the SAB-HES recommends that EPA incorporate infant mortality into the primary benefits estimate and that infant mortality be evaluated using an impact function developed from the Woodruff et al. (1997) study (SAB-HES, 2004).

Chronic Bronchitis. CB is characterized by mucus in the lungs and a persistent wet cough for at least 3 months a year for several years in a row. CB affects an estimated 5 percent of the U.S. population (American Lung Association, 1999). A limited number of studies have estimated the impact of air pollution on new incidences of CB. Schwartz (1993) and Abbey et al. (1995) provide evidence that long-term PM exposure gives rise to the development of CB in the United States. Because the CAVR is expected to reduce primarily $PM_{2.5}$, this analysis uses only the Abbey et al. (1995) study, because it is the only study focusing on the relationship between $PM_{2.5}$ and new incidences of CB.

Nonfatal Myocardial Infarctions (heart attacks). Nonfatal heart attacks have been linked with short-term exposures to $PM_{2.5}$ in the United States (Peters et al., 2001) and other countries (Poloniecki et al., 1997). We used a recent study by Peters et al. (2001) as the basis for the impact function estimating the relationship between $PM_{2.5}$ and nonfatal heart attacks. Peters et al. is the only available U.S. study to provide a specific estimate for heart attacks. Other studies, such as Samet et al. (2000) and Moolgavkar (2000), show a consistent relationship between all cardiovascular hospital admissions, including those for nonfatal heart attacks, and PM. Given the lasting impact of a heart attack on long-term health costs and earnings, we provide a separate estimate for nonfatal heart attacks. The estimate used in the CAVR analysis is based on the single available U.S. effect estimate. The finding of a specific impact on heart attacks is consistent with hospital admission and other studies showing relationships between fine particles and cardiovascular effects both within and outside the United States. Several epidemiologic studies (Liao et al., 1999; Gold et al., 2000; Magari et al., 2001) have shown that heart rate variability (an indicator of how much the heart is able to speed up or slow down in response to momentary stresses) is negatively related to PM levels. Heart rate variability is a risk factor for heart attacks and other coronary heart diseases (Carthenon et al., 2002; Dekker et al., 2000; Liao et al., 1997; Tsuji et al., 1996). As such, significant impacts of PM on heart rate variability are consistent with an increased risk of heart attacks.

Hospital and Emergency Room Admissions. Because of the availability of detailed hospital admission and discharge records, there is an extensive body of literature examining the relationship between hospital admissions and air pollution. Because of this, many of the hospital admission endpoints use pooled impact functions based on the results of a number of studies. In addition, some studies have examined the relationship between air pollution and emergency room visits. Since most emergency room visits do not result in an admission to the hospital (the majority of people going to the emergency room are treated and return home), we treat hospital admissions and emergency room visits separately, taking account of the fraction of emergency room visits that are admitted to the hospital.

The two main groups of hospital admissions estimated in this analysis are respiratory admissions and cardiovascular admissions. There is not much evidence linking ozone or PM with other types of hospital admissions. The only type of emergency room visits that have been consistently linked to ozone and PM in the United States are asthma-related visits.

To estimate avoided incidences of cardiovascular hospital admissions associated with $PM_{2.5}$, we used studies by Moolgavkar (2003) and Ito (2003). Additional published studies show a statistically significant relationship between PM_{10} and cardiovascular hospital admissions. However, given that the control scenarios we are analyzing are expected to reduce primarily $PM_{2.5}$, we focus on the two studies that examine $PM_{2.5}$. Both of these studies provide an effect estimate for populations over 65, allowing us to pool the impact functions for this age group. Only Moolgavkar (2000) provided a separate effect estimate for populations 20 to 64.[13] Total cardiovascular hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Cardiovascular hospital admissions include admissions for myocardial infarctions. To avoid double-counting benefits from reductions in myocardial infarctions when applying the impact function for cardiovascular hospital admissions, we first adjusted the baseline cardiovascular hospital admissions to remove admissions for myocardial infarctions.

To estimate total avoided incidences of respiratory hospital admissions, we used impact functions for several respiratory causes, including chronic obstructive pulmonary disease (COPD), pneumonia, and asthma. As with cardiovascular admissions, additional published studies show a statistically significant relationship between PM_{10} and respiratory hospital admissions. We used only those focusing on $PM_{2.5}$. Both Moolgavkar (2000) and Ito (2003) provide effect estimates for COPD in populations over 65, allowing us to pool the impact functions for this group. Only Moolgavkar (2000) provides a separate effect estimate for populations 20 to 64. Total COPD hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Only Ito (2003) estimated pneumonia and only for the population 65 and older. In addition, Sheppard (2003) provided an effect estimate for asthma hospital admissions for populations under age 65. Total avoided incidences of PM-related respiratory-related hospital admissions is the sum of COPD, pneumonia, and asthma admissions.

To estimate the effects of PM air pollution reductions on asthma-related ER visits, we use the effect estimate from a study of children 18 and under by Norris et al. (1999). As noted earlier, there is another study by Schwartz examining a broader age group (less than 65), but the Schwartz study focused on PM_{10} rather than $PM_{2.5}$. We selected the Norris et al. (1999) effect estimate because it better matched the pollutant of interest. Because children tend to have higher rates of hospitalization for asthma relative to adults under 65, we will

[13]Note that the Moolgavkar (2000) study has not been updated to reflect the more stringent GAM convergence criteria. However, given that no other estimates are available for this age group, we chose to use the existing study. Given the very small (<5 percent) difference in the effect estimates for people 65 and older with cardiovascular hospital admissions between the original and reanalyzed results, we do not expect this choice to introduce much bias.

likely capture the majority of the impact of $PM_{2.5}$ on asthma emergency room visits in populations under 65, although there may still be significant impacts in the adult population under 65.

Acute Health Events. As indicated in Table 4-1, in addition to mortality, chronic illness, and hospital admissions, a number of acute health effects not requiring hospitalization are associated with exposure to ambient levels of PM. The sources for the effect estimates used to quantify these effects are described below.

Around 4 percent of U.S. children between the ages of 5 and 17 experience episodes of acute bronchitis annually (American Lung Association, 2002c). Acute bronchitis is characterized by coughing, chest discomfort, slight fever, and extreme tiredness, lasting for a number of days. According to the MedlinePlus medical encyclopedia,[14] with the exception of cough, most acute bronchitis symptoms abate within 7 to 10 days. Incidence of episodes of acute bronchitis in children between the ages of 5 and 17 were estimated using an effect estimate developed from Dockery et al. (1996).

Incidences of lower respiratory symptoms (e.g., wheezing, deep cough) in children aged 7 to 14 were estimated using an effect estimate from Schwartz and Neas (2000).

Because asthmatics have greater sensitivity to stimuli (including air pollution), children with asthma can be more susceptible to a variety of upper respiratory symptoms (e.g., runny or stuffy nose; wet cough; and burning, aching, or red eyes). Research on the effects of air pollution on upper respiratory symptoms has thus focused on effects in asthmatics. Incidences of upper respiratory symptoms in asthmatic children aged 9 to 11 are estimated using an effect estimate developed from Pope et al. (1991).

Health effects from air pollution can also result in missed days of work (either from personal symptoms or from caring for a sick family member). Days of work lost due to $PM_{2.5}$ were estimated using an effect estimate developed from Ostro (1987).

MRAD result when individuals reduce most usual daily activities and replace them with less strenuous activities or rest, yet not to the point of missing work or school. For example, a mechanic who would usually be doing physical work most of the day will instead spend the day at a desk doing paper and phone work because of difficulty breathing or chest pain. The effect of $PM_{2.5}$ and ozone on MRAD was estimated using an effect estimate derived from Ostro and Rothschild (1989).

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[14]See http://www.nlm.nih.gov/medlineplus/ency/article/000124.htm, accessed January 2002.

For CAVR, we have followed the SAB-HES recommendations regarding asthma exacerbations in developing the primary estimate. To prevent double-counting, we focused the estimation on asthma exacerbations occurring in children and excluded adults from the calculation.[15] Asthma exacerbations occurring in adults are assumed to be captured in the general population endpoints such as work loss days and MRADs. Consequently, if we had included an adult-specific asthma exacerbation estimate, we would likely double-count incidence for this endpoint. However, because the general population endpoints do not cover children (with regard to asthmatic effects), an analysis focused specifically on asthma exacerbations for children (6 to 18 years of age) could be conducted without concern for double-counting.

To characterize asthma exacerbations in children, we selected two studies (Ostro et al., 2001; Vedal et al., 1998) that followed panels of asthmatic children. Ostro et al. (2001) followed a group of 138 African-American children in Los Angeles for 13 weeks, recording daily occurrences of respiratory symptoms associated with asthma exacerbations (e.g., shortness of breath, wheeze, and cough). This study found a statistically significant association between $PM_{2.5}$, measured as a 12-hour average, and the daily prevalence of shortness of breath and wheeze endpoints. Although the association was not statistically significant for cough, the results were still positive and close to significance; consequently, we decided to include this endpoint, along with shortness of breath and wheeze, in generating incidence estimates (see below). Vedal et al. (1998) followed a group of elementary school children, including 74 asthmatics, located on the west coast of Vancouver Island for 18

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[15]Estimating asthma exacerbations associated with air pollution exposures is difficult, because of concerns about double-counting of benefits. Concerns over double-counting stem from the fact that studies of the general population also include asthmatics, so estimates based solely on the asthmatic population cannot be directly added to the general population numbers without double-counting. In one specific case (upper respiratory symptoms in children), the only study available is limited to asthmatic children, so this endpoint can be readily included in the calculation of total benefits. However, other endpoints, such as lower respiratory symptoms and MRADs, are estimated for the total population that includes asthmatics. Therefore, to simply add predictions of asthma-related symptoms generated for the population of asthmatics to these total population-based estimates could result in double-counting, especially if they evaluate similar endpoints. The SAB-HES, in commenting on the analytical blueprint for 812, acknowledged these challenges in evaluating asthmatic symptoms and appropriately adding them into the primary analysis (SAB-HES, 2004). However, despite these challenges, the SAB-HES recommends the addition of asthma-related symptoms (i.e., asthma exacerbations) to the primary analysis, provided that the studies use the panel study approach and that they have comparable design and baseline frequencies in both asthma prevalence and exacerbation rates. Note also, that the SAB-HES, while supporting the incorporation of asthma exacerbation estimates, does not believe that the association between ambient air pollution, including ozone and PM, and the new onset of asthma is sufficiently strong to support inclusion of this asthma-related endpoint in the primary estimate.

months including measurements of daily peak expiratory flow (PEF) and the tracking of respiratory symptoms (e.g., cough, phlegm, wheeze, chest tightness) through the use of daily diaries. Association between PM_{10} and respiratory symptoms for the asthmatic population was only reported for two endpoints: cough and PEF. Because it is difficult to translate PEF measures into clearly defined health endpoints that can be monetized, we only included the cough-related effect estimate from this study in quantifying asthma exacerbations. We employed the following pooling approach in combining estimates generated using effect estimates from the two studies to produce a single asthma exacerbation incidence estimate. First, we pooled the separate incidence estimates for shortness of breath, wheeze, and cough generated using effect estimates from the Ostro et al. study, because each of these endpoints is aimed at capturing the same overall endpoint (asthma exacerbations) and there could be overlap in their predictions. The pooled estimate from the Ostro et al. study is then pooled with the cough-related estimate generated using the Vedal study. The rationale for this second pooling step is similar to the first; both studies are attempting to quantify the same overall endpoint (asthma exacerbations).

Additional epidemiological studies are available for characterizing asthma-related health endpoints (the full list of epidemiological studies considered for modeling asthma-related incidence is presented in Table 4-8). However, based on recommendations from the SAB-HES, we decided not to use these additional studies in generating the primary estimate. In particular, the Yu et al. (2000) estimates show a much higher baseline incidence rate than other studies, which may lead to an overstatement of the expected impacts in the overall asthmatic population. The Whittemore and Korn (1980) study did not use a well-defined endpoint, instead focusing on a respondent-defined "asthma attack." Other studies looked at respiratory symptoms in asthmatics but did not focus on specific exacerbations of asthma.

4.1.5.2 Uncertainties Associated with Health Impact Functions

Within-Study Variation. Within-study variation refers to the precision with which a given study estimates the relationship between air quality changes and health effects. Health effects studies provide both a "best estimate" of this relationship plus a measure of the statistical uncertainty of the relationship. The size of this uncertainty depends on factors such as the number of subjects studied and the size of the effect being measured. The results of even the most well-designed epidemiological studies are characterized by this type of uncertainty, though well-designed studies typically report narrower uncertainty bounds around the best estimate than do studies of lesser quality. In selecting health endpoints, we

Table 4-8. Studies Examining Health Impacts in the Asthmatic Population Evaluated for Use in the Benefits Analysis

Endpoint	Definition	Pollutant	Study	Study Population
Asthma Attack Indicators				
Shortness of breath	Prevalence of shortness of breath; incidence of shortness of breath	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8–13
Cough	Prevalence of cough; incidence of cough	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8–13
Wheeze	Prevalence of wheeze; incidence of wheeze	$PM_{2.5}$	Ostro et al. (2001)	African-American asthmatics, 8–13
Asthma exacerbation	≥1 mild asthma symptom: wheeze, cough, chest tightness, shortness of breath	PM_{10}, $PM_{1.0}$	Yu et al. (2000)	Asthmatics, 5–13
Cough	Prevalence of cough	PM_{10}	Vedal et al. (1998)	Asthmatics, 6–13
Other Symptoms/Illness Endpoints				
Upper respiratory symptoms	≥1 of the following: runny or stuffy nose; wet cough; burning, aching, or red eyes	PM_{10}	Pope et al. (1991)	Asthmatics, 9–11
Moderate or worse asthma	Probability of moderate (or worse) rating of overall asthma status	$PM_{2.5}$	Ostro et al. (1991)	Asthmatics, all ages
Acute bronchitis	≥1 episodes of bronchitis in the past 12 months	$PM_{2.5}$	McConnell et al. (1999)	Asthmatics, 9–15
Phlegm	"Other than with colds, does this child usually seem congested in the chest or bring up phlegm?"	$PM_{2.5}$	McConnell et al. (1999)	Asthmatics, 9–15
Asthma attacks	Respondent-defined asthma attack	$PM_{2.5}$, ozone	Whittemore and Korn (1980)	Asthmatics, all ages

generally focus on endpoints where a statistically significant relationship has been observed in at least some studies, although we may pool together results from studies with both statistically significant and insignificant estimates to avoid selection bias.

Across-Study Variation. Across-study variation refers to the fact that different published studies of the same pollutant/health effect relationship typically do not report identical findings; in some instances the differences are substantial. These differences can exist even between equally reputable studies and may result in health effect estimates that vary considerably. Across-study variation can result from two possible causes. One possibility is that studies report different estimates of the single true relationship between a given pollutant and a health effect because of differences in study design, random chance, or other factors. For example, a hypothetical study conducted in New York and one conducted in Seattle may report different C-R functions for the relationship between PM and mortality, in part because of differences between these two study populations (e.g., demographics, activity patterns). Alternatively, study results may differ because these two studies are in fact estimating different relationships; that is, the same reduction in PM in New York and Seattle may result in different reductions in premature mortality. This may result from a number of factors, such as differences in the relative sensitivity of these two populations to PM pollution and differences in the composition of PM in these two locations. In either case, where we identified multiple studies that are appropriate for estimating a given health effect, we generated a pooled estimate of results from each of those studies.

Application of C-R Relationship Nationwide. Regardless of the use of impact functions based on effect estimates from a single epidemiological study or multiple studies, each impact function was applied uniformly throughout the United States to generate health benefit estimates. However, to the extent that pollutant/health effect relationships are region specific, applying a location-specific impact function at all locations in the United States may result in overestimates of health effect changes in some locations and underestimates of health effect changes in other locations. It is not possible, however, to know the extent or direction of the overall effect on health benefit estimates introduced by applying a single impact function to the entire United States. This may be a significant uncertainty in the analysis, but the current state of the scientific literature does not allow for a region-specific estimation of health benefits.[16]

Extrapolation of Impact Functions Across Populations. Epidemiological studies often focus on specific age ranges, either due to data availability limitations (e.g., most hospital admission data come from Medicare records, which are limited to populations 65 and older) or to simplify data collection (e.g., some asthma symptom studies focus on children at summer camps, which usually have a limited age range). We have assumed for the primary analysis that most impact functions should be applied only to those populations with ages that strictly match the populations in the underlying epidemiological studies.

[16]Although we are not able to use region-specific effect estimates, we use region-specific baseline incidence rates where available. This allows us to take into account regional differences in health status, which can have a significant impact on estimated health benefits.

However, in many cases, there is no biological reason why the observed health effect would not also occur in other populations within a reasonable range of the studied population. For example, Dockery et al. (1996) examined acute bronchitis in children aged 8 to 12. There is no biological reason to expect a very different response in children aged 6 or 14. By excluding populations outside the range in the studies, we may be underestimating the health impact in the overall population. In response to recommendations from the SAB-HES, where there appears to be a reasonable physiological basis for expanding the age group associated with a specific effect estimate beyond the study population to cover the full age group (e.g., expanding from a study population of 7 to 11 year olds to the full 6- to 18-year child age group), we have done so and used those expanded incidence estimates in the primary analysis.

Uncertainties in the PM Mortality Relationship. A substantial body of published scientific literature demonstrates a correlation between elevated PM concentrations and increased premature mortality. However, much about this relationship is still uncertain. These uncertainties include the following:

<u>Causality</u>: Epidemiological studies are not designed to definitively prove causation. For the analysis of the CAVR, we assumed a causal relationship between exposure to elevated PM and premature mortality, based on the consistent evidence of a correlation between PM and mortality reported in the substantial body of published scientific literature.

<u>Other Pollutants</u>: PM concentrations are correlated with the concentrations of other criteria pollutants, such as ozone and CO. To the extent that there is correlation, this analysis may be assigning mortality effects to PM exposure that are actually the result of exposure to other pollutants. Recent studies (see Thurston and Ito [2001] and Bell et al. [2004]) have explored whether ozone may have mortality effects independent of PM. EPA is currently evaluating the epidemiological literature on the relationship between ozone and mortality.

<u>Shape of the C-R Function</u>: The shape of the true PM mortality C-R function is uncertain, but this analysis assumes the C-R function has a nonthreshold log-linear form throughout the relevant range of exposures. If this is not the correct form of the C-R function, or if certain scenarios predict concentrations well above the range of values for which the C-R function was fitted, avoided mortality may be misestimated. Although not included in the primary analysis, the potential impact of a health effects threshold on avoided incidences of PM-related premature mortality is explored as a key sensitivity analysis.

The possible existence of an effect threshold is a very important scientific question and issue for policy analyses such as this one. In 1999, the EPA SAB Advisory Council for Clean Air Compliance advised EPA that there was currently no scientific basis for selecting a threshold of 15 $\mu g/m^3$ or any other specific threshold for the PM-related health effects considered in typical benefits analyses (EPA-SAB-Council-ADV-99-012, 1999). In 2000, as a part of their review of benefits methods, the National Research Council concluded that there is no evidence for any departure from linearity in the observed range of exposure to PM_{10} or $PM_{2.5}$, nor any indication of a threshold (NRC, 2002). They cite the weight of evidence available from both short- and long-term exposure models and the similar effects found in cities with low and high ambient concentrations of PM. Most recently, EPA's updated (2004) Criteria Document states, "In summary, the available evidence does not either support or refute the existence of thresholds for effects of PM on mortality across the range of uncertainties in the studies." The PM criteria document identifies the general shape of exposure-response relationship(s) between PM and/or other pollutants and observed health effects (e.g., potential indications of thresholds), as an important issue and uncertainty in interpreting the overall PM epidemiology database.

These recommendations are supported by the recent literature on health effects of short- and long-term PM exposures (Daniels et al., 2000; Pope, 2000; Pope et al., 2002; Rossi et al., 1999; Schwartz and Zanobetti, 2000; Schwartz, Laden, and Zanobetti, 2002; Smith et al., 2000) that finds in most cases no evidence of a nonlinear relationship between PM and health effects and certainly does not find a distinct threshold. Recent cohort analyses by HEI (Krewski et al., 2000) and Pope et al. (2002) provide additional evidence of a quasi-linear relationship between long-term exposures to $PM_{2.5}$ and mortality. According to the latest draft PM criteria document, Krewski et al. (2000) found a "found a visually near-linear relationship between all-cause and cardiopulmonary mortality residuals and mean sulfate concentrations, near-linear between cardiopulmonary mortality and mean $PM_{2.5}$, but a somewhat nonlinear relationship between all-cause mortality residuals and mean $PM_{2.5}$ concentrations that flattens above ~20 $\mu g/m^3$. The confidence bands around the fitted curves are very wide, however, neither requiring a linear relationship nor precluding a nonlinear relationship if suggested by reanalyses" (Krewski et al. (2000), pages 8-138). The Pope et al. (2002) analysis, which represented an extension to the Krewski et al. analysis, found that the functions relating $PM_{2.5}$ and mortality are not significantly different from linear associations.

Based on the recent literature and advice from the SAB, we assume there are no thresholds for modeling health effects. Although not included in the primary analysis, the potential impact of a health effects threshold on avoided incidences of PM-related premature mortality is explored as a key sensitivity analysis.

Regional Differences: As discussed above, significant variability exists in the results of different PM/mortality studies. This variability may reflect regionally specific C-R functions resulting from regional differences in factors such as the physical and chemical composition of PM. If true regional differences exist, applying the PM/mortality C-R function to regions outside the study location could result in misestimation of effects in these regions.

Exposure/Mortality Lags: There is a time lag between changes in PM exposures and the total realization of changes in annual mortality rates. For the chronic PM/mortality relationship, the length of the lag is unknown and may be dependent on the kind of exposure. The existence of such a lag is important for the valuation of premature mortality incidence because economic theory suggests that benefits occurring in the future should be discounted. There is no specific scientific evidence of the existence or structure of a PM effects lag. However, current scientific literature on adverse health effects similar to those associated with PM (e.g., smoking-related disease) and the difference in the effect size between chronic exposure studies and daily mortality studies suggests that all incidences of premature mortality reduction associated with a given incremental change in PM exposure probably would not occur in the same year as the exposure reduction. The smoking-related literature also implies that lags of up to a few years or longer are plausible. The SAB-HES suggests that appropriate lag structures may be developed based on the distribution of cause-specific deaths within the overall all-cause estimate. Diseases with longer progressions should be characterized by long-term lag structures, while impacts occurring in populations with existing disease may be characterized by short-term lags.

A key question is the distribution of causes of death within the relatively broad categories analyzed in the cohort studies used. While we may be more certain about the appropriate length of cessation lag for lung cancer deaths, it is not clear what the appropriate lag structure should be for different types of cardiopulmonary deaths, which include both respiratory and cardiovascular causes. Some respiratory diseases may have a long period of progression, while others, such as pneumonia, have a very short duration. In the case of cardiovascular disease, there is an important question of whether air pollution is causing the disease, which would imply a relatively long cessation lag, or whether air pollution is causing premature death in individuals with preexisting heart disease, which would imply very short cessation lags.

The SAB-HES provides several recommendations for future research that could support the development of defensible lag structures, including the use of disease-specific lag models, and the construction of a segmented lag distribution to combine differential lags across causes of death. The SAB-HES recommended that until additional research has been completed, EPA should assume a segmented lag structure characterized by 30 percent of mortality reductions occurring in the first year, 50 percent occurring evenly over years 2 to 5 after the reduction in $PM_{2.5}$, and 20 percent occurring evenly over the years 6 to 20 after the reduction in $PM_{2.5}$. The distribution of deaths over the latency period is intended to reflect the contribution of short-term exposures in the first year, cardiopulmonary deaths in the 2- to 5-year period, and long-term lung disease and lung cancer in the 6- to 20-year period. For future analyses, the specific distribution of deaths over time will need to be determined through research on causes of death and progression of diseases associated with air pollution. It is important to keep in mind that changes in the lag assumptions do not change the total number of estimated deaths but rather the timing of those deaths.

Cumulative Effects: We attribute the PM/mortality relationship in the underlying epidemiological studies to cumulative exposure to PM. However, the relative roles of PM exposure duration and PM exposure level in inducing premature mortality remain unknown at this time.

4.1.5.3 Baseline Health Effect Incidence Rates

The epidemiological studies of the association between pollution levels and adverse health effects generally provide a direct estimate of the relationship of air quality changes to the relative risk of a health effect, rather than an estimate of the absolute number of avoided cases. For example, a typical result might be that a 10 $\mu g/m^3$ decrease in daily $PM_{2.5}$ levels might decrease hospital admissions by 3 percent. The baseline incidence of the health effect is necessary to convert this relative change into a number of cases. The baseline incidence rate provides an estimate of the incidence rate (number of cases of the health effect per year, usually per 10,000 or 100,000 general population) in the assessment location corresponding to baseline pollutant levels in that location. To derive the total baseline incidence per year, this rate must be multiplied by the corresponding population number (e.g., if the baseline incidence rate is number of cases per year per 100,000 population, it must be multiplied by the number of 100,000s in the population).

Some epidemiological studies examine the association between pollution levels and adverse health effects in a specific subpopulation, such as asthmatics or diabetics. In these cases, it is necessary to develop not only baseline incidence rates, but also prevalence rates for the defining condition (e.g., asthma). For both baseline incidence and prevalence data, we use age-specific rates where available. Impact functions are applied to individual age groups and then summed over the relevant age range to provide an estimate of total population benefits.

In most cases, because of a lack of data or methods, we have not attempted to project incidence rates to future years, instead assuming that the most recent data on incidence rates is the best prediction of future incidence rates. In recent years, better data on trends in incidence and prevalence rates for some endpoints, such as asthma, have become available. We are working to develop methods to use these data to project future incidence rates. However, for our primary benefits analysis of the final CAVR, we continue to use current incidence rates.

Table 4-9 summarizes the baseline incidence data and sources used in the benefits analysis. We use the most geographically disaggregated data available. For premature mortality, county-level data are available. For hospital admissions, regional rates are available. However, for all other endpoints, a single national incidence rate is used, due to a lack of more spatially disaggregated data. In these cases, we used national incidence rates whenever possible, because these data are most applicable to a national assessment of benefits. However, for some studies, the only available incidence information comes from the studies themselves; in these cases, incidence in the study population is assumed to represent typical incidence at the national level.

Age, cause, and county-specific mortality rates were obtained from the U.S. Centers for Disease Control and Prevention (CDC) for the years 1996 through 1998. CDC maintains an online data repository of health statistics, CDC Wonder, accessible at http://wonder.cdc.gov/. The mortality rates provided are derived from U.S. death records and U.S. Census Bureau postcensal population estimates. Mortality rates were averaged across 3 years (1996 through 1998) to provide more stable estimates. When estimating rates for age groups that differed from the CDC Wonder groupings, we assumed that rates were uniform across all ages in the reported age group. For example, to estimate mortality rates for individuals ages 30 and up, we scaled the 25- to 34-year-old death count and population by one-half and then generated a population-weighted mortality rate using data for the older age groups. Note that we have not projected any changes in mortality rates over time. We are aware that the U.S. Census projections of total and age-specific mortality rates used in our population projections are based on projections of declines in mortality rates for younger populations and increases in mortality rates for older populations over time. We are

Table 4-9. Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population

		Rates	
Endpoint	**Parameter**	**Value**	**Source**[a]
Mortality	Daily or annual mortality rate	Age-, cause-, and county-specific rate	CDC Wonder (1996–1998)
Hospitalizations	Daily hospitalization rate	Age-, region-, and cause-specific rate	1999 NHDS public use data files[b]
Asthma ER Visits	Daily asthma ER visit rate	Age- and region-specific visit rate	2000 NHAMCS public use data files[c]; 1999 NHDS public use data files[b]
Chronic Bronchitis	Annual prevalence rate per person • Aged 18–44 • Aged 45–64 • Aged 65 and older	 0.0367 0.0505 0.0587	1999 NHIS (American Lung Association, 2002b, Table 4)
	Annual incidence rate per person	0.00378	Abbey et al. (1993, Table 3)
Nonfatal Myocardial Infarction (heart attacks)	Daily nonfatal myocardial infarction incidence rate per person, 18+ • Northeast • Midwest • South • West	 0.0000159 0.0000135 0.0000111 0.0000100	1999 NHDS public use data files[b]; adjusted by 0.93 for probability of surviving after 28 days (Rosamond et al., 1999)
Asthma Exacerbations	Incidence (and prevalence) among asthmatic African-American children • daily wheeze • daily cough • daily dyspnea	 0.076 (0.173) 0.067 (0.145) 0.037 (0.074)	Ostro et al. (2001)
	Prevalence among asthmatic children • daily wheeze • daily cough • daily dyspnea	 0.038 0.086 0.045	Vedal et al. (1998)
Acute Bronchitis	Annual bronchitis incidence rate, children	0.043	American Lung Association (2002c, Table 11)

(continued)

Table 4-9. Baseline Incidence Rates and Population Prevalence Rates for Use in Impact Functions, General Population (continued)

Endpoint	Parameter	Rates	
		Value	Source[a]
Lower Respiratory Symptoms	Daily lower respiratory symptom incidence among children[d]	0.0012	Schwartz et al. (1994, Table 2)
Upper Respiratory Symptoms	Daily upper respiratory symptom incidence among asthmatic children	0.3419	Pope et al. (1991, Table 2)
Work Loss Days	Daily WLD incidence rate per person (18–65) • Aged 18–24 • Aged 25–44 • Aged 45–64	 0.00540 0.00678 0.00492	1996 HIS (Adams et al., 1999, Table 41); U.S. Bureau of the Census (2000)
Minor Restricted-Activity Days	Daily MRAD incidence rate per person	0.02137	Ostro and Rothschild (1989, p. 243)

[a] The following abbreviations are used to describe the national surveys conducted by the National Center for Health Statistics: HIS refers to the National Health Interview Survey; NHDS—National Hospital Discharge Survey; NHAMCS—National Hospital Ambulatory Medical Care Survey.

[b] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHDS/.

[c] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHAMCS/.

[d] Lower respiratory symptoms are defined as two or more of the following: cough, chest pain, phlegm, and wheeze.

evaluating the most appropriate way to incorporate these projections into our database of county-level cause-specific mortality rates. In the interim, we have not attempted to adjust future mortality rates. This will lead to an overestimate of mortality benefits in future years, with the overestimation bias increasing as benefits are projected into the future. We do not at this time have a quantified estimate of the magnitude of the potential bias in the years analyzed for this rule (2015).

For the set of endpoints affecting the asthmatic population, in addition to baseline incidence rates, prevalence rates of asthma in the population are needed to define the applicable population. Table 4-9 lists the baseline incidence rates and their sources for asthma symptom endpoints. Table 4-10 lists the prevalence rates used to determine the applicable population for asthma symptom endpoints. Note that these reflect current asthma prevalence and assume no change in prevalence rates in future years. As noted above, we are investigating methods for projecting asthma prevalence rates in future years.

Table 4-10. Asthma Prevalence Rates Used to Estimate Asthmatic Populations in Impact Functions

	Asthma Prevalence Rates	
Population Group	**Value**	**Source**
All Ages	0.0386	American Lung Association (2002a, Table 7)—based on 1999 HIS
< 18	0.0527	American Lung Association (2002a, Table 7)—based on 1999 HIS
5–17	0.0567	American Lung Association (2002a, Table 7)—based on 1999 HIS
18–44	0.0371	American Lung Association (2002a, Table 7)—based on 1999 HIS
45–64	0.0333	American Lung Association (2002a, Table 7)—based on 1999 HIS
65+	0.0221	American Lung Association (2002a, Table 7)—based on 1999 HIS
Male, 27+	0.021	2000 HIS public use data files[a]
African American, 5 to 17	0.0726	American Lung Association (2002a, Table 9)—based on 1999 HIS
African American, <18	0.0735	American Lung Association (2002a, Table 9)—based on 1999 HIS

[a] See ftp://ftp.cdc.gov/pub/Health_Statistics/NCHS/Datasets/NHIS/2000/.

4.1.5.4 Selecting Unit Values for Monetizing Health Endpoints

The appropriate economic value for a change in a health effect depends on whether the health effect is viewed *ex ante* (before the effect has occurred) or *ex post* (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health affects by a small amount for a large population. The appropriate economic measure is therefore *ex ante* WTP for changes in risk. However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use this data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a measure is able to reduce the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $100, then the WTP for an avoided statistical premature mortality amounts to $1 million ($100/0.0001 change in risk). Using this approach, the size of the affected population is automatically taken into account by the number of incidences predicted by epidemiological studies applied to the relevant population. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as a primary estimate. For example, for the valuation of hospital admissions we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These COI estimates generally understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. Table 4-11 summarizes the value estimates per health effect that we used in this analysis. Values are presented both for a 1990 base income level and adjusted for income growth in the future analysis year, 2015. Note that the unit values for hospital admissions are the weighted averages of the ICD-9 code-specific values for the group of ICD-9 codes included in the hospital admission categories. A discussion of the valuation methods for premature mortality and CB is provided here because of the relative importance of these effects. Discussions of the methods used to value nonfatal myocardial infarctions (heart attacks) and school absence days are provided because these endpoints have only recently been added to the analysis and the valuation methods are still under development. In the following discussions, unit values are presented at 1990 levels of income for consistency with previous analyses. Equivalent future-year values can be obtained from Table 4-11. COI estimates are converted to constant 1999 dollar equivalents using the medical CPI.

4.1.5.4.1 Valuing Reductions in Premature Mortality Risk. We estimate the monetary benefit of reducing premature mortality risk using the VSL approach, which is a summary measure for the value of small changes in mortality risk experienced by a large number of people. The mean value of avoiding one statistical death is assumed to be $5.5 million in 1999 dollars. This represents a central value consistent with the range of values suggested by recent meta-analyses of the wage-risk VSL literature. The distribution of VSL is characterized by a confidence interval from $1 to $10 million, based on two meta-analyses of the wage-risk VSL literature. The $1 million lower confidence limit represents the lower end of the interquartile range from the Mrozek and Taylor (2002) meta-analysis. The $10 million upper confidence limit represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis. Because the majority of the studies in these meta-analyses are based on datasets from the early 1990s or previous decades, we continue to assume that the VSL estimates provided by those meta-analyses are in 1990 income equivalents. Future research might provide income-adjusted VSL values for individual studies that can be incorporated into the meta-analyses. This would allow for a more reliable base-year estimate for use in adjusting VSL for aggregate changes in income over time.

Table 4-11. Unit Values Used for Economic Valuation of Health Endpoints (1999$)

Health Endpoint	Central Estimate of Value Per Statistical Incidence: 1990 Income Level	Central Estimate of Value Per Statistical Incidence: 2015 Income Level	Derivation of Estimates
Premature Mortality (Value of a Statistical Life)	$5,500,000	$6,400,000	Point estimate is the mean of a normal distribution with a 95 percent confidence interval between $1 and $10 million. Confidence interval is based on two meta-analyses of the wage-risk VSL literature: $1 million represents the lower end of the interquartile range from the Mrozek and Taylor (2002) meta-analysis and $10 million represents the upper end of the interquartile range from the Viscusi and Aldy (2003) meta-analysis. The VSL represents the value of a small change in mortality risk aggregated over the affected population.
Chronic Bronchitis (CB)	$340,000	$400,000	Point estimate is the mean of a generated distribution of WTP to avoid a case of pollution-related CB. WTP to avoid a case of pollution-related CB is derived by adjusting WTP (as described in Viscusi et al., [1991]) to avoid a severe case of CB for the difference in severity and taking into account the elasticity of WTP with respect to severity of CB.
Nonfatal Myocardial Infarction (heart attack)			Age-specific cost-of-illness values reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI. Lost earnings estimates are based on Cropper and Krupnick (1990). Direct medical costs are based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990).
<u>3% discount rate</u>			
Age 0–24	$66,902	$66,902	<u>Lost earnings</u>:
Age 25–44	$74,676	$74,676	Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings:
Age 45–54	$78,834	$78,834	<u>Age of onset</u>: <u>at 3%</u> <u>at 7%</u>
Age 55–65	$140,649	$140,649	25-44 $8,774 $7,855
Age 66 and over	$66,902	$66,902	45-54 $12,932 $11,578
<u>7% discount rate</u>			55-65 $74,746 $66,920
Age 0–24	$65,293	$65,293	<u>Direct medical expenses</u>: An average of:
Age 25–44	$73,149	$73,149	1. Wittels et al. (1990) ($102,658—no discounting)
Age 45–54	$76,871	$76,871	2. Russell et al. (1998), 5-year period ($22,331 at 3% discount rate; $21,113 at 7% discount rate)
Age 55–65	$132,214	$132,214	
Age 66 and over	$65,293	$65,293	

(continued)

Table 4-11. Unit Values Used for Economic Valuation of Health Endpoints (1999$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence		Derivation of Estimates
	1990 Income Level	2015 Income Level	
Hospital Admissions			
Chronic Obstructive Pulmonary Disease (COPD) (ICD codes 490-492, 494-496)	$12,378	$12,378	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Pneumonia (ICD codes 480-487)	$14,693	$14,693	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total pneumonia category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Asthma Admissions	$6,634	$6,634	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
All Cardiovascular (ICD codes 390-429)	$18,387	$18,387	The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Emergency Room Visits for Asthma	$286	$286	Simple average of two unit COI values: (1) $311.55, from Smith et al. (1997) and (2) $260.67, from Stanford et al. (1999).

(continued)

Table 4-11. Unit Values Used for Economic Valuation of Health Endpoints (1999$) (continued)

Health Endpoint	Central Estimate of Value Per Statistical Incidence: 1990 Income Level	Central Estimate of Value Per Statistical Incidence: 2015 Income Level	Derivation of Estimates
Respiratory Ailments Not Requiring Hospitalization			
Upper Respiratory Symptoms (URS)	$25	$26	Combinations of the three symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in seven different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for URS is the average of the dollar values for the seven different types of URS.
Lower Respiratory Symptoms (LRS)	$16	$17	Combinations of the four symptoms for which WTP estimates are available that closely match those listed by Schwartz et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS.
Asthma Exacerbations	$42	$44	Asthma exacerbations are valued at $42 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma attack is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study.
Acute Bronchitis	$360	$380	Assumes a 6-day episode, with daily value equal to the average of low and high values for related respiratory symptoms recommended in Neumann et al. (1994).
Restricted Activity and Work/School Loss Days			
Work Loss Days (WLDs)	Variable (national median =)		County-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5—to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
Minor Restricted Activity Days (MRADs)	$51	$54	Median WTP estimate to avoid one MRAD from Tolley et al. (1986).

As indicated in the previous section on quantification of premature mortality benefits, we assumed for this analysis that some of the incidences of premature mortality related to PM exposures occur in a distributed fashion over the 20 years following exposure. To take this into account in the valuation of reductions in premature mortality, we applied an annual 3 percent discount rate to the value of premature mortality occurring in future years.[17]

The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Regardless of the theoretical economic considerations, EPA prefers not to draw distinctions in the monetary value assigned to the lives saved even if they differ in age, health status, socioeconomic status, gender, or other characteristic of the adult population.

Following the advice of the EEAC of the SAB, EPA currently uses the VSL approach in calculating the primary estimate of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for reductions in mortality risk (EPA-SAB-EEAC-00-013, 2000). Although there are several differences between the labor market studies EPA uses to derive a VSL estimate and the PM air pollution context addressed here, those differences in the affected populations and the nature of the risks imply both upward and downward adjustments. Table 4-12 lists some of these differences and the expected effect on the VSL estimate for air pollution-related mortality. In the absence of a comprehensive and balanced set of adjustment factors, EPA believes it is reasonable to continue to use the $5.5 million value while acknowledging the significant limitations and uncertainties in the available literature.

The SAB-EEAC has reviewed many potential VSL adjustments and the state of the economics literature. The SAB-EEAC advised EPA to "continue to use a wage-risk-based VSL as its primary estimate, including appropriate sensitivity analyses to reflect the uncertainty of these estimates," and that "the only risk characteristic for which adjustments

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[17]The choice of a discount rate, and its associated conceptual basis, is a topic of ongoing discussion within the Federal government. EPA adopted a 3 percent discount rate for its base estimate in this case to reflect reliance on a "social rate of time preference" discounting concept. We have also calculated benefits and costs using a 7 percent rate consistent with an "opportunity cost of capital" concept to reflect the time value of resources directed to meet regulatory requirements. In this case, the benefit and cost estimates were not significantly affected by the choice of discount rate. Further discussion of this topic appears in EPA's *Guidelines for Preparing Economic Analyses* (EPA, 2000b).

Table 4-12. Expected Impact on Estimated Benefits of Premature Mortality Reductions of Differences Between Factors Used in Developing Applied VSL and Theoretically Appropriate VSL

Attribute	Expected Direction of Bias
Age	Uncertain, perhaps overestimate
Life Expectancy/Health Status	Uncertain, perhaps overestimate
Attitudes Toward Risk	Underestimate
Income	Uncertain
Voluntary vs. Involuntary	Uncertain, perhaps underestimate
Catastrophic vs. Protracted Death	Uncertain, perhaps underestimate

to the VSL can be made is the timing of the risk" (EPA-SAB-EEAC-00-013, EPA, 2000). In developing our primary estimate of the benefits of premature mortality reductions, we have followed this advice and discounted over the lag period between exposure and premature mortality.

Uncertainties Specific to Premature Mortality Valuation. The economic benefits associated with premature mortality are the largest category of monetized benefits of the final CAVR. In addition, in prior analyses, EPA has identified valuation of mortality benefits as the largest contributor to the range of uncertainty in monetized benefits (see EPA [1999a]).[18] Because of the uncertainty in estimates of the value of premature mortality avoidance, it is important to adequately characterize and understand the various types of economic approaches available for mortality valuation. Such an assessment also requires an understanding of how alternative valuation approaches reflect that some individuals may be more susceptible to air pollution-induced mortality or reflect differences in the nature of the risk presented by air pollution relative to the risks studied in the relevant economics literature.

The health science literature on air pollution indicates that several human characteristics affect the degree to which mortality risk affects an individual. For example,

[18]This conclusion was based on a assessment of uncertainty based on statistical error in epidemiological effect estimates and economic valuation estimates. Additional sources of model error such as those examined in the pilot PM mortality expert elicitation may result in different conclusions about the relative contribution of sources of uncertainty.

some age groups appear to be more susceptible to air pollution than others (e.g., the elderly and children). Health status prior to exposure also affects susceptibility. An ideal benefits estimate of mortality risk reduction would reflect these human characteristics, in addition to an individual's WTP to improve one's own chances of survival plus WTP to improve other individuals' survival rates. The ideal measure would also take into account the specific nature of the risk reduction commodity that is provided to individuals, as well as the context in which risk is reduced. To measure this value, it is important to assess how reductions in air pollution reduce the risk of dying from the time that reductions take effect onward and how individuals value these changes. Each individual's survival curve, or the probability of surviving beyond a given age, should shift as a result of an environmental quality improvement. For example, changing the current probability of survival for an individual also shifts future probabilities of that individual's survival. This probability shift will differ across individuals because survival curves depend on such characteristics as age, health state, and the current age to which the individual is likely to survive.

Although a survival curve approach provides a theoretically preferred method for valuing the benefits of reduced risk of premature mortality associated with reducing air pollution, the approach requires a great deal of data to implement. The economic valuation literature does not yet include good estimates of the value of this risk reduction commodity. As a result, in this study we value avoided premature mortality risk using the VSL approach.

Other uncertainties specific to premature mortality valuation include the following:

- Across-study variation: There is considerable uncertainty as to whether the available literature on VSL provides adequate estimates of the VSL saved by air pollution reduction. Although there is considerable variation in the analytical designs and data used in the existing literature, the majority of the studies involve the value of risks to a middle-aged working population. Most of the studies examine differences in wages of risky occupations, using a wage-hedonic approach. Certain characteristics of both the population affected and the mortality risk facing that population are believed to affect the average WTP to reduce the risk. The appropriateness of a distribution of WTP based on the current VSL literature for valuing the mortality-related benefits of reductions in air pollution concentrations therefore depends not only on the quality of the studies (i.e., how well they measure what they are trying to measure), but also on the extent to which the risks being valued are similar and the extent to which the subjects in the studies are similar to the population affected by changes in pollution concentrations.

- Level of risk reduction: The transferability of estimates of the VSL from the wage-risk studies to the context of the CAVR analysis rests on the assumption that, within a reasonable range, WTP for reductions in mortality risk is linear in risk reduction. For example, suppose a study estimates that the average WTP for a reduction in mortality risk of 1/100,000 is $50, but that the actual mortality risk reduction resulting from a given pollutant reduction is 1/10,000. If WTP for reductions in mortality risk is linear in risk reduction, then a WTP of $50 for a reduction of 1/100,000 implies a WTP of $500 for a risk reduction of 1/10,000 (which is 10 times the risk reduction valued in the study). Under the assumption of linearity, the estimate of the VSL does not depend on the particular amount of risk reduction being valued. This assumption has been shown to be reasonable provided the change in the risk being valued is within the range of risks evaluated in the underlying studies (Rowlatt et al., 1998).

- Voluntariness of risks evaluated: Although job-related mortality risks may differ in several ways from air pollution-related mortality risks, the most important difference may be that job-related risks are incurred voluntarily, or generally assumed to be, whereas air pollution-related risks are incurred involuntarily. Some evidence suggests that people will pay more to reduce involuntarily incurred risks than risks incurred voluntarily. If this is the case, WTP estimates based on wage-risk studies may understate WTP to reduce involuntarily incurred air pollution-related mortality risks.

- Sudden versus protracted death: A final important difference related to the nature of the risk may be that some workplace mortality risks tend to involve sudden, catastrophic events, whereas air pollution-related risks tend to involve longer periods of disease and suffering prior to death. Some evidence suggests that WTP to avoid a risk of a protracted death involving prolonged suffering and loss of dignity and personal control is greater than the WTP to avoid a risk (of identical magnitude) of sudden death. To the extent that the mortality risks addressed in this assessment are associated with longer periods of illness or greater pain and suffering than are the risks addressed in the valuation literature, the WTP measurements employed in the present analysis would reflect a downward bias.

- Self-selection and skill in avoiding risk: Recent research (Shogren and Stamland, 2002) suggests that VSL estimates based on hedonic wage studies may overstate the average value of a risk reduction. This is based on the fact that the risk-wage trade-off revealed in hedonic studies reflects the preferences of the marginal worker (i.e., that worker who demands the highest compensation for his risk reduction). This worker must have either higher risk, lower risk tolerance, or both. However, the risk estimate used in hedonic studies is generally based on average risk, so the VSL may be upwardly biased because the wage differential and risk measures do not match.

4.1.5.4.2 Valuing Reductions in the Risk of Chronic Bronchitis. The best available estimate of WTP to avoid a case of CB comes from Viscusi et al. (1991). The Viscusi et al. study, however, describes a severe case of CB to the survey respondents. We therefore employ an estimate of WTP to avoid a pollution-related case of CB, based on adjusting the Viscusi et al. (1991) estimate of the WTP to avoid a severe case. This is done to account for the likelihood that an average case of pollution-related CB is not as severe. The adjustment is made by applying the elasticity of WTP with respect to severity reported in the Krupnick and Cropper (1992) study. Details of this adjustment procedure are provided in the Benefits TSD for the Nonroad Diesel rulemaking (Abt Associates, 2003).

We use the mean of a distribution of WTP estimates as the central tendency estimate of WTP to avoid a pollution-related case of CB in this analysis. The distribution incorporates uncertainty from three sources: the WTP to avoid a case of severe CB, as described by Viscusi et al.; the severity level of an average pollution-related case of CB (relative to that of the case described by Viscusi et al.); and the elasticity of WTP with respect to severity of the illness. Based on assumptions about the distributions of each of these three uncertain components, we derive a distribution of WTP to avoid a pollution-related case of CB by statistical uncertainty analysis techniques. The expected value (i.e., mean) of this distribution, which is about $331,000 (2000$), is taken as the central tendency estimate of WTP to avoid a PM-related case of CB.

4.1.5.4.3 Valuing Reductions in Nonfatal Myocardial Infarctions (Heart Attacks). The Agency has recently incorporated into its analyses the impact of air pollution on the expected number of nonfatal heart attacks, although it has examined the impact of reductions in other related cardiovascular endpoints. We were not able to identify a suitable WTP value for reductions in the risk of nonfatal heart attacks. Instead, we use a COI unit value with two components: the direct medical costs and the opportunity cost (lost earnings) associated with the illness event. Because the costs associated with a myocardial infarction extend beyond the initial event itself, we consider costs incurred over several years. Using age-specific annual lost earnings estimated by Cropper and Krupnick (1990) and a 3 percent discount rate, we estimated a present discounted value in lost earnings (in 2000$) over 5 years due to a myocardial infarction of $8,774 for someone between the ages of 25 and 44, $12,932 for someone between the ages of 45 and 54, and $74,746 for someone between the ages of 55 and 65. The corresponding age-specific estimates of lost earnings (in 2000$) using a 7 percent discount rate are $7,855, $11,578, and $66,920, respectively. Cropper and Krupnick (1990) do not provide lost earnings estimates for populations under 25 or over 65. As such, we do not include lost earnings in the cost estimates for these age groups.

We found three possible sources in the literature of estimates of the direct medical costs of myocardial infarction:

- Wittels et al. (1990) estimated expected total medical costs of myocardial infarction over 5 years to be $51,211 (in 1986$) for people who were admitted to the hospital and survived hospitalization. (There does not appear to be any discounting used.) Wittels et al. was used to value coronary heart disease in the 812 Retrospective Analysis of the Clean Air Act. Using the CPI-U for medical care, the Wittels estimate is $109,474 in year 2000$. This estimated cost is based on a medical cost model, which incorporated therapeutic options, projected outcomes, and prices (using "knowledgeable cardiologists" as consultants). The model used medical data and medical decision algorithms to estimate the probabilities of certain events and/or medical procedures being used. The authors note that the average length of hospitalization for acute myocardial infarction has decreased over time (from an average of 12.9 days in 1980 to an average of 11 days in 1983). Wittels et al. used 10 days as the average in their study. It is unclear how much further the length of stay for myocardial infarction may have decreased from 1983 to the present. The average length of stay for ICD code 410 (myocardial infarction) in the year-2000 Agency for Healthcare Research and Quality (AHRQ) HCUP database is 5.5 days. However, this may include patients who died in the hospital (not included among our nonfatal myocardial infarction cases), whose length of stay was therefore substantially shorter than it would be if they had not died.

- Eisenstein et al. (2001) estimated 10-year costs of $44,663 in 1997$, or $49,651 in 2000$ for myocardial infarction patients, using statistical prediction (regression) models to estimate inpatient costs. Only inpatient costs (physician fees and hospital costs) were included.

- Russell et al. (1998) estimated first-year direct medical costs of treating nonfatal myocardial infarction of $15,540 (in 1995$) and $1,051 annually thereafter. Converting to year 2000$, that would be $23,353 for a 5-year period (without discounting) or $29,568 for a 10-year period.

In summary, the three different studies provided significantly different values (see Table 4-13).

As noted above, the estimates from these three studies are substantially different, and we have not adequately resolved the sources of differences in the estimates. Because the wage-related opportunity cost estimates from Cropper and Krupnick (1990) cover a 5-year

Table 4-13. Alternative Direct Medical Cost of Illness Estimates for Nonfatal Heart Attacks

Study	Direct Medical Costs (2000$)	Over an x-Year Period, for x =
Wittels et al. (1990)	$109,474[a]	5
Russell et al. (1998)	$22,331[b]	5
Eisenstein et al. (2001)	$49,651[b]	10
Russell et al. (1998)	$27,242[b]	10

[a] Wittels et al. did not appear to discount costs incurred in future years.

[b] Using a 3 percent discount rate.

period, we used estimates for medical costs that similarly cover a 5-year period (i.e., estimates from Wittels et al. (1990) and Russell et al. (1998). We used a simple average of the two 5-year estimates, or $65,902, and added it to the 5-year opportunity cost estimate. The resulting estimates are given in Table 4-14.

Table 4-14. Estimated Costs Over a 5-Year Period (in 2000$) of a Nonfatal Myocardial Infarction

Age Group	Opportunity Cost	Medical Cost[a]	Total Cost
0–24	$0	$65,902	$65,902
25–44	$8,774[b]	$65,902	$74,676
45–54	$12,253[b]	$65,902	$78,834
55–65	$70,619[b]	$65,902	$140,649
> 65	$0	$65,902	$65,902

[a] An average of the 5-year costs estimated by Wittels et al. (1990) and Russell et al. (1998).

[b] From Cropper and Krupnick (1990), using a 3 percent discount rate.

4.1.6 Human Welfare Impact Assessment

PM and ozone have numerous documented effects on environmental quality that affect human welfare. These welfare effects include direct damages to property, either through impacts on material structures or by soiling of surfaces, direct economic damages in the form of lost productivity of crops and trees, indirect damages through alteration of ecosystem functions, and indirect economic damages through the loss in value of recreational experiences or the existence value of important resources. EPA's Criteria Documents for PM and ozone list numerous physical and ecological effects known to be linked to ambient concentrations of these pollutants (EPA, 1996a; 1996b). This section describes individual effects and how we quantify and monetize them. These effects include changes in commercial crop and forest yields, visibility, and nitrogen deposition to estuaries.

4.1.6.1 Visibility Benefits

Changes in the level of ambient PM caused by the reduction in emissions from CAVR will change the level of visibility in much of the Eastern United States. Visibility directly affects people's enjoyment of a variety of daily activities. Individuals value visibility both in the places they live and work, in the places they travel to for recreational purposes, and at sites of unique public value, such as the Great Smokey Mountains National Park. This section discusses the measurement of the economic benefits of improved visibility.

It is difficult to quantitatively define a visibility endpoint that can be used for valuation. Increases in PM concentrations cause increases in light extinction, a measure of how much the components of the atmosphere absorb light. More light absorption means that the clarity of visual images and visual range is reduced, *ceteris paribus.* Light absorption is a variable that can be accurately measured. Sisler (1996) created a unitless measure of visibility, the *deciview*, based directly on the degree of measured light absorption. Deciviews are standardized for a reference distance in such a way that one deciview corresponds to a change of about 10 percent in available light. Sisler characterized a change in light extinction of one deciview as "a small but perceptible scenic change under many circumstances." Air quality models were used to predict the change in visibility, measured in deciviews, of the areas affected by the control scenarios.[19]

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[19]A change of less than 10 percent in the light extinction budget represents a measurable improvement in visibility but may not be perceptible to the eye in many cases. Some of the average regional changes in visibility are less than one deciview (i.e., less than 10 percent of the light extinction budget) and thus less than perceptible. However, this does not mean that these changes are not real or significant. Our

EPA considers benefits from two categories of visibility changes: residential visibility and recreational visibility. In both cases economic benefits are believed to consist of use values and nonuse values. Use values include the aesthetic benefits of better visibility, improved road and air safety, and enhanced recreation in activities like hunting and birdwatching. Nonuse values are based on people's beliefs that the environment ought to exist free of human-induced haze. Nonuse values may be more important for recreational areas, particularly national parks and monuments.

Residential visibility benefits are those that occur from visibility changes in urban, suburban, and rural areas and also in recreational areas not listed as Federal Class I areas.[20] For the purposes of this analysis, recreational visibility improvements are defined as those that occur specifically in Federal Class I areas. A key distinction between recreational and residential benefits is that only those people living in residential areas are assumed to receive benefits from residential visibility, while all households in the United States are assumed to derive some benefit from improvements in Class I areas. Values are assumed to be higher if the Class I area is located close to their home.[21]

Only two existing studies provide defensible monetary estimates of the value of visibility changes. One is a study on residential visibility conducted in 1990 (McClelland et al., 1993) and the other is a 1988 survey on recreational visibility value (Chestnut and Rowe, 1990a; 1990b). Although there are a number of other studies in the literature, they were conducted in the early 1980s and did not use methods that are considered defensible by current standards. Both the Chestnut and Rowe and McClelland et al. studies use the CV method. There has been a great deal of controversy and significant development of both theoretical and empirical knowledge about how to conduct CV surveys in the past decade. In EPA's judgment, the Chestnut and Rowe study contains many of the elements of a valid CV study and is sufficiently reliable to serve as the basis for monetary estimates of the benefits

assumption is then that individuals can place values on changes in visibility that may not be perceptible. This is quite plausible if individuals are aware that many regulations lead to small improvements in visibility that, when considered together, amount to perceptible changes in visibility.

[20]The Clean Air Act designates 156 national parks and wilderness areas as Class I areas for visibility protection.

[21]For details of the visibility estimates discussed in this chapter, please refer to the Benefits TSD for the Nonroad Diesel rulemaking (Abt Associates, 2003).

of visibility changes in recreational areas.[22] This study serves as an essential input to our estimates of the benefits of recreational visibility improvements in the primary benefits estimates. Consistent with SAB advice, EPA has designated the McClelland et al. study as significantly less reliable for regulatory benefit-cost analysis, although it does provide useful estimates on the order of magnitude of residential visibility benefits (EPA-SAB-COUNCIL-ADV-00-002, 1999). Residential visibility benefits are not calculated for this analysis.

The Chestnut and Rowe study measured the demand for visibility in Class I areas managed by the National Park Service (NPS) in three broad regions of the country: California, the Southwest, and the Southeast. Respondents in five States were asked about their WTP to protect national parks or NPS-managed wilderness areas within a particular region. The survey used photographs reflecting different visibility levels in the specified recreational areas. The visibility levels in these photographs were later converted to deciviews for the current analysis. The survey data collected were used to estimate a WTP equation for improved visibility. In addition to the visibility change variable, the estimating equation also included household income as an explanatory variable.

The Chestnut and Rowe study did not measure values for visibility improvement in Class I areas outside the three regions. Their study covered 86 of the 156 Class I areas in the United States. We can infer the value of visibility changes in the other Class I areas by transferring values of visibility changes at Class I areas in the study regions. A complete description of the benefits transfer method used to infer values for visibility changes in Class I areas outside the study regions is provided in the Benefits TSD for the Nonroad Diesel rulemaking (Abt Associates, 2003).

The Chestnut and Rowe study (Chestnut and Rowe, 1990a; 1990b), although representing the best available estimates, has a number of limitations. These include the following:

- The age of the study (late 1980s) will increase the uncertainty about the correspondence of the estimated values to those that might be provided by current or future populations.

[22]An SAB advisory letter indicates that "many members of the Council believe that the Chestnut and Rowe study is the best available" (EPA-SAB-COUNCIL-ADV-00-002, 1999, p. 13). However, the committee did not formally approve use of these estimates because of concerns about the peer-reviewed status of the study. EPA believes the study has received adequate review and has been cited in numerous peer-reviewed publications (Chestnut and Dennis, 1997).

- The survey focused only on populations in five States, so the application of the estimated values to populations outside those States requires that preferences of populations in the five surveyed States be similar to those of nonsurveyed States.

- There is an inherent difficulty in separating values expressed for visibility improvements from an overall value for improved air quality. The Chestnut and Rowe study attempted to control for this by informing respondents that "other households are being asked about visibility, human health, and vegetation protections in urban areas and at national parks in other regions." However, most of the respondents did not feel that they were able to segregate visibility at national parks entirely from residential visibility and health effects.

- It is not clear exactly what visibility improvements the respondents to the Chestnut and Rowe survey were valuing. For the purpose of the benefits analysis for this rule, EPA assumed that respondents provided values for changes in annual average visibility. Because most policies will result in a shift in the distribution of visibility (usually affecting the worst days more than the best days), the annual average may not be the most relevant metric for policy analysis.

- The WTP question asked about changes in average visibility. However, the survey respondents were shown photographs of only summertime conditions, when visibility is generally at its worst. It is possible that the respondents believed those visibility conditions held year-round, in which case they would have been valuing much larger overall improvements in visibility than what otherwise would be the case.

- The survey did not include reminders of possible substitutes (e.g., visibility at other parks) or budget constraints. These reminders are considered to be best practice for stated preference surveys.

- The Chestnut and Rowe survey focused on visibility improvements in and around national parks and wilderness areas. The survey also focused on visibility improvements of national parks in the southwest United States. Given that national parks and wilderness areas exhibit unique characteristics, it is not clear whether the WTP estimate obtained from Chestnut and Rowe can be transferred to other national parks and wilderness areas, without introducing additional uncertainty.

In general, the survey design and implementation reflect the period in which the survey was conducted. Since that time, many improvements to the stated preference methodology have been developed. As future survey efforts are completed, EPA will incorporate values for visibility improvements reflecting the improved survey designs.

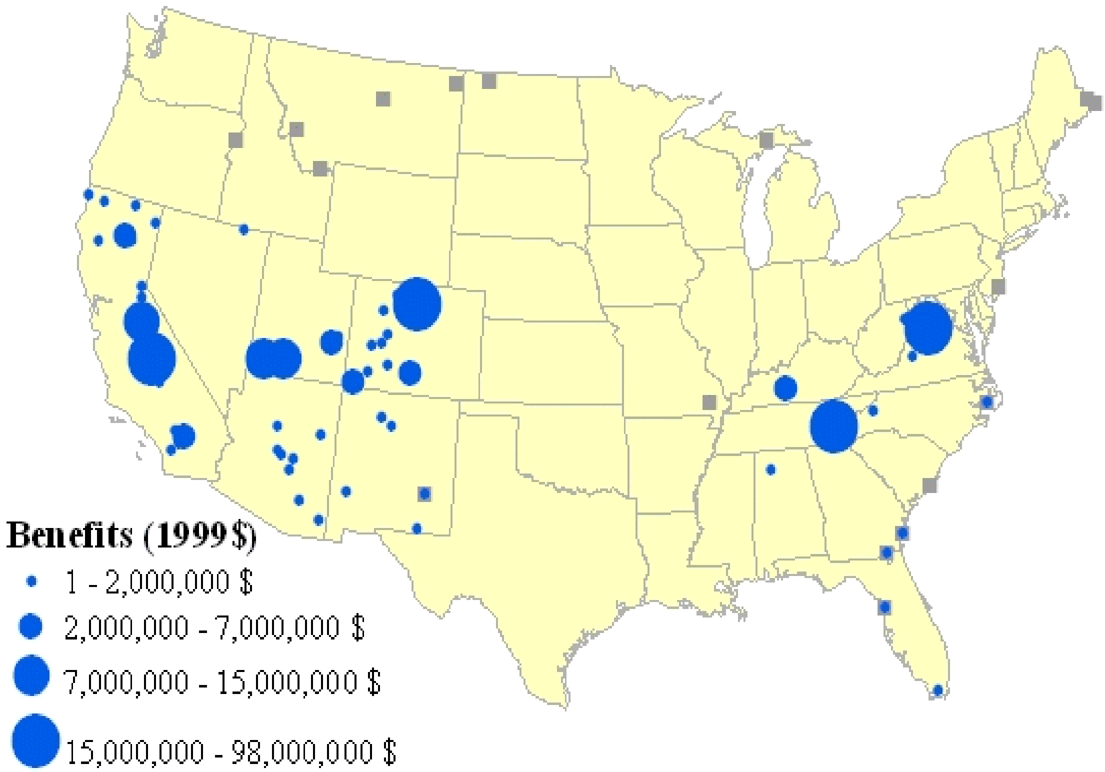
The estimated relationship from the Chestnut and Rowe study is only directly applicable to the populations represented by survey respondents. EPA used benefits transfer methodology to extrapolate these results to the population affected by the final CAVR. A general WTP equation for improved visibility (measured in deciviews) was developed as a function of the baseline level of visibility, the magnitude of the visibility improvement, and household income. The behavioral parameters of this equation were taken from analysis of the Chestnut and Rowe data. These parameters were used to calibrate WTP for the visibility changes resulting from CAVR. The method for developing calibrated WTP functions is based on the approach developed by Smith et al. (2002). Available evidence indicates that households are willing to pay more for a given visibility improvement as their income increases (Chestnut, 1997). The benefits estimates here incorporate Chestnut's estimate that a 1 percent increase in income is associated with a 0.9 percent increase in WTP for a given change in visibility.

Using the methodology outlined above, EPA estimates that the total WTP for the visibility improvements annually in Southeastern and Southwestern Class I areas brought about by CAVR range from $84 to $420 million in 2015. This value includes the value to households living in the same State as the Class I area as well as values for all households in the United States living outside the State containing the Class I area, and the value accounts for growth in real income.

We know that additional visibility benefits will occur in other parks in the country and in urban areas. Those benefits are described in Chapter 3, and an analysis of the potential dollar value of the benefits is included in Appendix F of this report.

The benefits resulting from visibility improvements in Southeastern and Southwestern Class I areas included in the primary monetized benefits estimates under the final CAVR are presented in Figure 4-2. This figure presents these benefits in terms of the total benefits modeled for each of the Class I areas (i.e., the "Park Benefits" map) in the 81 Class I areas included in the study.

One major source of uncertainty for the visibility benefits estimate is the benefits transfer process used. Judgments used to choose the functional form and key parameters of the estimating equation for WTP for the affected population could have significant effects on the size of the estimates. Assumptions about how individuals respond to changes in visibility that are either very small or outside the range covered in the Chestnut and Rowe study could also affect the results.



* Map shows monetized primary visibility benefits in the Southeast and Southwest.

Figure 4-2. CAVR Final Rule Visibility Improvements in Class I Areas in the Southeast and Southwest

4.1.6.2 Agricultural, Forestry, and Other Vegetation-Related Benefits

The Ozone Criteria Document notes that ozone affects vegetation throughout the United States, impairing crops, native vegetation, and ecosystems more than any other air pollutant (EPA, 1996a, page 5-11). Changes in ground-level ozone resulting from the control scenarios are expected to affect crop and forest yields throughout the affected area.

Well-developed techniques exist to provide monetary estimates of these benefits to agricultural producers and to consumers. These techniques use models of planting decisions, yield response functions, and the supply of and demand for agricultural products. The resulting welfare measures are based on predicted changes in market prices and production costs. Models also exist to measure benefits to silvicultural producers and consumers. However, these models have not been adapted for use in analyzing ozone-related forest impacts. Because of resource limitations, we are unable to provide agricultural or benefits estimates for the final CAVR rule.

4.1.6.2.1 Agricultural Benefits. Laboratory and field experiments have shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN), examined 15 species and numerous cultivars. The NCLAN results show that several economically important crop species are sensitive to ozone levels typical of those found in the United States (EPA, 1996a). In addition, economic studies have shown a relationship between observed ozone levels and crop yields (Garcia et al., 1986).

4.1.6.2.2 Forestry Benefits. Ozone also has been shown conclusively to cause discernible injury to forest trees (EPA, 1996a; Fox and Mickler, 1996). In our previous analysis of the HD Engine/Diesel Fuel rule, we were able to quantify the effects of changes in ozone concentrations on tree growth for a limited set of species. Because of resource limitations, we were not able to quantify such impacts for this analysis.

4.1.6.2.3 Other Vegetation Effects. An additional welfare benefit expected to accrue as a result of reductions in ambient ozone concentrations in the United States is the economic value the public receives from reduced aesthetic injury to forests. There is sufficient scientific information available to reliably establish that ambient ozone levels cause visible injury to foliage and impair the growth of some sensitive plant species (EPA, 1996a). However, present analytic tools and resources preclude EPA from quantifying the benefits of improved forest aesthetics.

Urban ornamentals (floriculture and nursery crops) represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels and likely to affect large economic sectors. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative economic benefits analysis has been conducted. The farm production value of ornamental crops was estimated at over $14 billion in 2003 (USDA, 2004). This is therefore a potentially important welfare effects category. However, information and valuation methods are not available to allow for plausible estimates of the percentage of these expenditures that may be related to impacts associated with ozone exposure.

The CAVR program, by reducing NO_x emissions, will also reduce nitrogen deposition on agricultural land and forests. There is some evidence that nitrogen deposition may have positive effects on agricultural output through passive fertilization. Holding all other factors constant, farmers' use of purchased fertilizers or manure may increase as deposited nitrogen is reduced. Estimates of the potential value of this possible increase in the use of purchased fertilizers are not available, but it is likely that the overall value is very small relative to other health and welfare effects. The share of nitrogen requirements provided by this deposition is small, and the marginal cost of providing this nitrogen from alternative sources is quite low. In some areas, agricultural lands suffer from nitrogen oversaturation due to an abundance of on-farm nitrogen production, primarily from animal manure. In these areas, reductions in atmospheric deposition of nitrogen represent additional agricultural benefits.

Information on the effects of changes in passive nitrogen deposition on forests and other terrestrial ecosystems is very limited. The multiplicity of factors affecting forests, including other potential stressors such as ozone, and limiting factors such as moisture and other nutrients, confound assessments of marginal changes in any one stressor or nutrient in forest ecosystems. However, reductions in the deposition of nitrogen could have negative effects on forest and vegetation growth in ecosystems where nitrogen is a limiting factor (EPA, 1993).

On the other hand, there is evidence that forest ecosystems in some areas of the United States are nitrogen saturated (EPA, 1993). Once saturation is reached, adverse effects of additional nitrogen begin to occur such as soil acidification, which can lead to leaching of nutrients needed for plant growth and mobilization of harmful elements such as aluminum. Increased soil acidification is also linked to higher amounts of acidic runoff to streams and lakes and leaching of harmful elements into aquatic ecosystems.

4.1.6.3 Benefits from Reductions in Materials Damage

The control scenarios that we modeled are expected to produce economic benefits in the form of reduced materials damage. There are two important categories of these benefits. Household soiling refers to the accumulation of dirt, dust, and ash on exposed surfaces. Criteria pollutants also have corrosive effects on commercial/industrial buildings and structures of cultural and historical significance. The effects on historic buildings and outdoor works of art are of particular concern because of the uniqueness and irreplaceability of many of these objects.

Previous EPA benefits analyses have been able to provide quantitative estimates of household soiling damage. Consistent with SAB advice, we determined that the existing data (based on consumer expenditures from the early 1970s) are too out of date to provide a reliable estimate of current household soiling damages (EPA-SAB-COUNCIL-ADV-98-003, 1998).

EPA is unable to estimate any benefits to commercial and industrial entities from reduced materials damage. Nor is EPA able to estimate the benefits of reductions in PM-related damage to historic buildings and outdoor works of art. Existing studies of damage to this latter category in Sweden (Grosclaude and Soguel, 1994) indicate that these benefits could be an order of magnitude larger than household soiling benefits.

4.1.6.4 Benefits from Reduced Ecosystem Damage

The effects of air pollution on the health and stability of ecosystems are potentially very important but are at present poorly understood and difficult to measure. The reductions in NO_x caused by the final rule could produce significant benefits. Excess nutrient loads, especially of nitrogen, cause a variety of adverse consequences to the health of estuarine and coastal waters. These effects include toxic and/or noxious algal blooms such as brown and red tides, low (hypoxic) or zero (anoxic) concentrations of dissolved oxygen in bottom waters, the loss of submerged aquatic vegetation due to the light-filtering effect of thick algal mats, and fundamental shifts in phytoplankton community structure (Bricker et al., 1999).

Direct functions relating changes in nitrogen loadings to changes in estuarine benefits are not available. The preferred WTP-based measure of benefits depends on the availability of these functions and on estimates of the value of environmental responses. Because neither appropriate functions nor sufficient information to estimate the marginal value of changes in water quality exist at present, calculation of a WTP measure is not possible.

If better models of ecological effects can be defined, EPA believes that progress can be made in estimating WTP measures for ecosystem functions. These estimates would be superior to avoided cost estimates in placing economic values on the welfare changes associated with air pollution damage to ecosystem health. For example, if nitrogen or sulfate loadings can be linked to measurable and definable changes in fish populations or definable indexes of biodiversity, then CV studies can be designed to elicit individuals' WTP for changes in these effects. This is an important area for further research and analysis and will require close collaboration among air quality modelers, natural scientists, and economists.

4.2 Benefits Analysis—Results

Applying the impact and valuation functions described previously in this chapter to the estimated changes in visibility and ambient PM yields estimates of the changes in physical damages (e.g., premature mortalities, cases, admissions) and the associated monetary values for those changes. Estimates of physical health impacts are presented in Table 4-15. Monetized values for both health and welfare endpoints are presented in Table 4-16, along with total aggregate monetized benefits. All of the monetary benefits are in constant-year 1999 dollars.

Not all known PM- and ozone-related health and welfare effects could be quantified or monetized. The monetized value of these unquantified effects is represented by adding an unknown "B" to the aggregate total. The estimate of total monetized health benefits is thus equal to the subset of monetized PM- and ozone-related health and welfare benefits plus B, the sum of the nonmonetized health and welfare benefits.

Total monetized benefits are dominated by benefits of mortality risk reductions. The primary analysis estimate projects that the final rule will result in 1,600 avoided premature deaths annually for the Scenario 2 in 2015. Note that unaccounted for changes in baseline mortality rates over time may lead to reductions in the estimated number of avoided premature mortalities.

Our estimate of total monetized benefits in 2015 for the final rule ranges from $2.2 billion to $14.3 billion depending upon the scenario analyzed and the discount rates of 3 and 7 percent. Health benefits account for over 98 percent of total benefits, in part because we are unable to quantify most of the nonhealth benefits. These unquantified benefits may be substantial and could exceed the costs of the rule, although the magnitude of these benefits is highly uncertain. The monetized benefit associated with reductions in the risk of premature mortality, which accounts for $9.2 billion in 2015 for Scenario 2, is over 90 percent of total monetized health benefits. The next largest benefit is for reductions in chronic illness (CB and nonfatal heart attacks), although this value is more than an order of magnitude lower than for premature mortality. Hospital admissions for respiratory and cardiovascular causes, visibility, MRADs, work loss days, school absence days, and worker productivity account for the majority of the remaining benefits. The remaining categories each account for a small percentage of total benefit; however, they represent a large number of avoided incidences affecting many individuals. A comparison of the incidence table to the monetary benefits

Table 4-15. Clean Air Visibility Rule: Estimated Reduction in Incidence of Adverse Health Effects[a]

Health Effect	Incidence Reduction		
	Scenario 1	Scenario 2	Scenario 3
Premature Mortality[b,c]			
Adult, age 30 and over	400	1,600	2,300
Infant, age <1 year	1	4	5
Chronic bronchitis (adult, age 26 and over)	230	890	1,300
Nonfatal myocardial infarction (adults, age 18 and older)	570	2,200	3,000
Hospital admissions—respiratory (all ages)[d]	140	510	720
Hospital admissions—cardiovascular (adults, age >18)[e]	120	450	640
Emergency room visits for asthma (age 18 years and younger)	370	1,300	1,800
Acute bronchitis (children, age 8–12)	550	2,100	3,000
Lower respiratory symptoms (children, age 7–14)	6,600	25,000	36,000
Upper respiratory symptoms (asthmatic children, age 9–18)	5,000	19,000	27,000
Asthma exacerbation (asthmatic children, age 6–18)	8,100	31,000	44,000
Work loss days (adults, age 18–65)	44,000	170,000	240,000
Minor restricted-activity days (adults, age 18–65)	260,000	1,000,000	1,400,000

[a] Incidences are rounded to two significant digits. These estimates represent benefits for CAVR Nationwide for the final CAVR program relative to a baseline with CAIR inclusive of the proposal to include SO_2 and annual NO_x controls for New Jersey and Delaware. Note these estimates may be slightly understated due to the inclusion in CAIR of SO_2 and annual NO_x controls for Arkansas. The baseline used to estimates these benefits does not consider the recently promulgated CAMR.

[c] PM premature mortality impacts for adults are based on application of the effect estimate derived from the Pope et al. (2002) cohort study. Infant premature mortality based upon studies by Woodruff et al., 1997.

[d] Respiratory hospital admissions for PM include admissions for COPD, pneumonia, and asthma.

[e] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

Table 4-16. Estimated Monetary Value of Reductions in Incidence of Health and Welfare Effects Associated with the CAVR (millions of 1999$)[a,b]

Effect	Estimated Value of Reductions Scenario 1	Scenario 2	Scenario 3
Health Effects:			
Premature mortality[c,d]			
Adult, age 30 and over			
3% discount rate	$2,330	$9,180	$13,000
7% discount rate	$1,960	$7,730	$10,900
Infant, < 1 year	$6.12	$23.8	$34.2
Chronic bronchitis (adults, 26 and over)	90.5	353	498
Nonfatal acute myocardial infarctions			
3% discount rate	$49.3	$189	$264
7% discount rate	$45.8	$176	$245
Hospital admissions for respiratory causes	1.07	4.03	5.65
Hospital admissions for cardiovascular causes	2.6	10	14.1
Emergency room visits for asthma	0.106	0.362	0.51
Acute bronchitis (children, age 8–12)	0.207	0.79	1.12
Lower respiratory symptoms (children, 7–14)	0.109	0.415	0.587
Upper respiratory symptoms (asthma, 9–11)	0.137	0.523	0.74
Asthma exacerbations	0.367	1.4	1.98
Work loss days	5.56	22.4	31.5
Minor restricted-activity days (MRADs)	13.8	54.1	76.3
Welfare Effects:			
Recreational visibility, 81 Class I areas	$84	$239	$416
Monetized Total[e]			
Base Estimate:			
3% discount rate	$2,600 + B	$10,100 + B	$14,300 + B
7% discount rate	$2,200 + B	$8,600 + B	$12,200 + B

[a] Monetary benefits are rounded to three significant digits for ease of presentation and computation. Benefits in this table are nationwide (with the exception of visibility) and are associated with NO_x and SO_2 reductions. Visibility benefits relate to Class I areas in the southeastern and southwestern United States. These estimates represent benefits for CAVR Nationwide for the final CAVR program relative to a baseline with CAIR inclusive of the proposal to include SO_2 and annual NO_x controls for New Jersey and Delaware. Note these estimates may be slightly understated due to the inclusion in CAIR of SO_2 and annual NO_x controls for Arkansas. Note also that the recently promulgated CAMR was not considered in the baseline used to develop these estimates.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990and 2015.

[c] Valuation assumes discounting over the SAB recommended 20 year segmented lag structure described earlier. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000b; OMB, 2003).

[d] Adult premature mortality estimates based upon studies by Pope et al., 2002. Infant premature mortality based upon Woodruff et al., 1997.

[e] B represents the monetary value of health and welfare benefits and disbenefits not monetized. A detailed listing is provided in Table 4-2. Column totals are rounded to the nearest 100 million dollars, and totals may not sum due to rounding.

table reveals that there is not always a close correspondence between the number of incidences avoided for a given endpoint and the monetary value associated with that endpoint. For example, there are almost 100 times more work loss days than premature mortalities, yet work loss days account for only a very small fraction of total monetized benefits. This reflects the fact that many of the less severe health effects, while more common, are valued at a lower level than the more severe health effects. Also, some effects, such as hospital admissions, are valued using a proxy measure of WTP. As such, the true value of these effects may be higher than that reported in Table 4-16.

4.3 Uncertainty in the Benefits Estimates

Characterization of health-related benefits associated with PM reductions is a complex process which is subject to a variety of potential sources of uncertainty. Key assumptions underlying the estimate of avoided premature mortality include the following:

- Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been established, the weight of the available epidemiological and experimental evidence supports an assumption of causality.

- All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.

- The C-R function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM including both regions that are in attainment with the fine particle standards and those that do not meet the standard.

- The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Use of the Pope et al., 2002-derived mortality function to support this analysis is associated with uncertainty resulting from: (a) potential of the study to incompletely capture short-term exposure-related mortality effects, (b) potential mis-match between study and analysis populations which introduces various forms of bias into the results, and (c) failure to identify all key confounders and effects modifiers, which could result in incorrect effects estimates relating morality to $PM_{2.5}$ exposure. EPA is researching methods to characterize all elements of uncertainty in the dose-response function for mortality. As is discussed in detail in the CAIR RIA (EPA, 2005), EPA has used two methods to quantify uncertainties in the mortality function, including: the statistical uncertainty derived from the standard errors reported in the Pope et al., 2002 study, and the use of results of a pilot expert elicitation conducted in 2004 to investigate other uncertainties in the mortality estimate. In the CAIR benefit analysis, the statistical uncertainty from the standard error of the Pope et al., 2002 study was twice the mean benefit estimate at the 95th percentile and one-fourth of the mean at the 5th percentile, while the expert elicitation provided mean estimates that ranged in value from less than one-third of the mean estimate from the Pope et al., 2002 study-based estimate to two and one-half times the Pope et al., 2002-based estimate. The confidence intervals from the pilot elicitation applied to the CAIR benefit analysis ranged in value from zero at the 5th percentile to a value at the 95th percentile that is seven times higher than the Pope et al., 2002-based estimate. These results are highly dependent on the air quality scenarios applied to the concentration-response functions of the Pope et all, 2002 study and the pilot expert elicitation. Thus, the characterization of uncertainty discussed in the CAIR RIA could differ greatly from what would be observed for CAVR due to differences in population-weighted changes in concentrations of $PM_{2.5}$ (i.e., the location of populations exposure relative to the changes in air quality), and may be especially sensitive to the differences in baseline $PM_{2.5}$ air quality experienced by populations prior to implementation of the CAVR. Table 4-17 shows the mean estimate and estimated 5th and 95th percentiles of premature deaths avoided for our primary estimate based on the Pope et al. (2002) study and based on the responses for each of the 5 experts. This table shows that for each scenario, our primary estimates are higher than four of the experts and lower than one expert and falls within the uncertainty bounds of all but one expert. The table shows that for Scenario 2, the average estimated annual number of premature deaths

Table 4-17. Results of Illustrative Application of Pilot Expert Elicitation: Annual Reductions in Premature Mortality in 2015 Associated with the Clean Air Visibility Rule

Source of Mortality Estimate	Scenario 1			Scenario 2			Scenario 3		
	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Pope et al. (2002)	170	405	640	680	1,600	2,500	960	2,300	3,500
Expert A	0	330	630	0	1,300	2,500	0	1,800	3,500
Expert B	0	100	440	0	490	2,200	0	670	3,000
Expert C	0	65	220	0	310	950	0	420	1,300
Expert D	0	280	840	0	1,100	3,300	0	1,600	4,700
Expert E	0	550	1,300	0	2,200	5,200	0	3,100	7,300

avoided in 2015 ranges from approximately 310 (based on the judgments of Expert C) to 2,200 (based on the judgments of Expert E). The statistical uncertainty bounds (5^{th} to 95^{th} percentile) of all of the estimates, including the Pope et al.-based distribution, overlap. Although the uncertainty bounds for each expert include zero, and some distributions have significant percentiles at zero, all of the distributions have a positive mean estimate. EPA is continuing its research of methods to characterize uncertainty in total benefits estimates, and is conducting a full-scale expert elicitation. The full-scale expert elicitation is scheduled to be completed by the end of 2005.

4.4 Discussion

This analysis has estimated the health and welfare benefits of reductions in ambient concentrations of particulate matter and ozone resulting from reduced emissions of NO_x and SO_2 from affected sources. The result suggests there will be significant health and welfare benefits arising from regulating emissions from BART eligible sources in the United States. Our estimate that 1,600 premature mortalities would be avoided when the emissions reductions from the regulation are fully realized provides additional evidence of the important role that pollution from these sources plays in the public health impacts of air pollution.

Other uncertainties that we could not quantify include the importance of unquantified effects and uncertainties in the modeling of ambient air quality. Inherent in any analysis of future regulatory programs are uncertainties in projecting atmospheric conditions and source-level emissions, as well as population, health baselines, incomes, technology, and other factors. The assumptions used to capture these elements are reasonable based on the available evidence. However, data limitations prevent an overall quantitative estimate of the uncertainty associated with estimates of total economic benefits. If one is mindful of these limitations, the magnitude of the benefits estimates presented here can be useful information in expanding the understanding of the public health impacts of reducing air pollution from the sources affected by this rule.

EPA will continue to evaluate new methods and models and select those most appropriate for estimating the health benefits of reductions in air pollution. It is important to continue improving benefits transfer methods in terms of transferring economic values and transferring estimated impact functions. The development of both better models of current health outcomes and new models for additional health effects such as asthma, high blood pressure, and adverse birth outcomes (such as low birth weight) will be essential to future improvements in the accuracy and reliability of benefits analyses (Guo et al., 1999; Ibald-

Mulli et al., 2001). Enhanced collaboration between air quality modelers, epidemiologists, toxicologists, and economists should result in a more tightly integrated analytical framework for measuring health benefits of air pollution policies.

4.5 Cost Effectiveness Analysis

Health-based cost-effectiveness analysis (CEA) and cost-utility analysis (CUA) have been used to analyze numerous health interventions but have not been widely adopted as tools to analyze environmental policies. The Office of Management and Budget (OMB) recently issued Circular A-4 guidance on regulatory analyses, requiring Federal agencies to "prepare a CEA for all major rulemakings for which the primary benefits are improved public health and safety to the extent that a valid effectiveness measure can be developed to represent expected health and safety outcomes." Environmental quality improvements may have multiple health and ecological benefits, making application of CEA more difficult and less straightforward. For CAIR CEA may provide a useful framework for evaluation: non-health benefits are substantial, but the majority of quantified benefits come from health effects. EPA included in the CAIR RIA (EPA, 2005) a preliminary and experimental application of one type of CEA—a modified quality-adjusted life-years (QALYs) approach. For CAIR, we concluded that the direct usefulness of cost-effectiveness analysis is mitigated by the lack of rule alternatives to compare relative effectiveness, but that comparisons could still be made to other benchmarks bearing in mind methodological differences.

QALYs were developed to evaluate the effectiveness of individual medical treatments, and EPA is still evaluating the appropriate methods for CEA for environmental regulations. Agency concerns with the standard QALY methodology include the treatment of people with fewer years to live (the elderly); fairness to people with preexisting conditions that may lead to reduced life expectancy and reduced quality of life; and how the analysis should best account for nonhealth benefits, such as improved visibility.

The Institute of Medicine (a member institution of the National Academies of Science) has established the Committee to Evaluate Measures of Health Benefits for Environmental, Health, and Safety Regulation to assess the scientific validity, ethical implications, and practical utility of a wide range of effectiveness measures used or proposed in CEA. This committee is expected to produce a report by the end of 2005. In the interim, however, agencies are expected to provide CEAs for rules covered by Circular A-4 requirements.

In Appendix G of the RIA for the CAIR (EPA, 2005), we conducted an extensive cost-effectiveness analysis using morbidity inclusive life years (MILY). That analysis concluded that the reductions in $PM_{2.5}$ associated with CAIR are expected to be cost-saving (because the value of expenditures on illnesses and non-health benefits exceed costs), and that costs of the CAIR could have been significantly higher and still result in cost-effective improvements in public health. Because the age distribution of the mortality and chronic disease reductions is not expected to differ between CAVR and CAIR, one can draw inferences by examining the relative magnitude of the costs and health impacts between them even in the absence of a formal cost-effectiveness analysis for CAVR. While CAVR is not expected to be cost-saving like CAIR, we expect that CAVR is likely to have a relatively low cost per MILY.

For Scenario 2, reductions in the incidences of mortality, chronic bronchitis, and non-fatal heart attacks are 1,600, 890, and 2,200, respectively. These are roughly 10 percent of the corresponding incidences in the CAIR rule (16,700, 8,700, and 22,000, respectively). Total MILY gained in the CAIR rule in 2015 was estimated to be 250,000. Assuming the difference in MILY between the rules would be roughly proportional to the difference in incidence (which should be the case because both rules are analyzed for a 2015 population), then Scenario 2 would result in roughly 25,000 MILY. The costs of Scenario 2 are estimated at $1.4 billion (using a 3% discount rate). Costs of illness for chronic bronchitis and non-fatal heart attacks are expected to be $270 million, while the value of other health benefits and visibility improvements is estimated to be $330 million. Subtracting these from the CAVR costs gives a net cost of $800 million. Dividing this by the approximate estimate of MILY yields a net cost per MILY of $32,000. This estimate is close to the median cost per QALY for respiratory and cardiovascular interventions of $31,000 (2002$) reported in the Harvard Cost Utility Database (http://www.hsph.harvard.edu/cearegistry/index.html).

These results are suggestive, but should be interpreted with caution for several reasons. First, in the analysis for CAIR the use of a 7% discount rate instead of 3 percent significantly reduced cost-effectiveness, and CAVR estimates are likely to be similarly affected by a 7 percent discount rate. Second, if the CAVR confidence intervals on the number of MILY are proportional to those in CAIR, it is less clear that the net cost per MILY will be less than the $50,000 cost-effectiveness benchmark. Finally, by construction MILY will generally be greater than standard QALYs for a given reduction in incidence, which will bias cost-effectiveness comparisons to common QALY benchmarks. Even with these caveats, the results indicate that CAVR as likely to be cost-effective and to compare favorably with other health interventions.

4.6 References

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CHAPTER 5

QUALITATIVE ASSESSMENT OF NONMONETIZED BENEFITS

5.1 Introduction

In addition to the enumerated human health and welfare benefits resulting from reductions in ambient levels of PM and ozone, BART will result in benefits that we are not able to monetize. This chapter discusses welfare benefits associated with reduced sulfur and nitrogen deposition that affects acidification of ecosystems and eutrophication in water bodies. Other welfare benefits including potential visibility improvements, agricultural yield increases, forestry production increases, reductions in soiling and materials damage, mercury health and welfare benefits, and other welfare categories are discussed in Chapter 4 of this report.

5.2 Atmospheric Deposition of Sulfur and Nitrogen—Impacts on Aquatic, Forest, and Coastal Ecosystems

Reductions in atmospheric deposition of sulfur and nitrogen are anticipated to occur across the nation as a result of this rule. Atmospheric deposition of sulfur and nitrogen, more commonly known as acid rain, occurs when emissions of SO_2 and NO_x react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to Earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds transport the acidic compounds hundreds of miles, often across state and national borders. Acidic compounds (including small particles such as sulfates and nitrates) cause many negative environmental effects. These pollutants

- acidify lakes and streams,
- harm sensitive forests, and
- harm sensitive coastal ecosystems.

The effect of atmospheric deposition of acids on freshwater and forest ecosystems depends largely on the ecosystem's ability to neutralize the acid (Driscoll et al., 2001). This is referred to as an ecosystem's acid neutralizing capacity (ANC). Acid neutralization occurs when positively charged ions such as calcium, potassium, sodium, and magnesium, collectively known as base cations, are released. As water moves through a watershed, two important chemical processes act to neutralize acids. The first involves cation exchange in soils, a process by which hydrogen ions from the acid deposition displace other cations from the surface of soil particles, releasing these cations to soil and surface water. The second process is mineral weathering, where base cations bound in the mineral structure of rocks are released as the minerals gradually break down over long time periods. As the base cations are released by weathering, they neutralize acidity and increase the pH level in soil water and surface waters. Acid deposition, because it consists of acid anions (e.g., sulfate, nitrate), leaches some of the accumulated base cation reserves from the soils into drainage waters. The leaching rate of these base cations may accelerate to the point where it significantly exceeds the resupply via weathering (Driscoll et al., 2001). BART is expected to reduce atmospheric deposition of nitrogen and sulfur and to reduce the total nitrogen and sulfur loads.

Soils, forests, surface waters and aquatic biota (fish, algae, and the rest), and coastal ecosystems share water, nutrients, and other essential ecosystem components and are inextricably linked by the chemical processes described above. For example, the same base cations that help to neutralize acidity in lakes and streams are also essential nutrients in forest soils, meaning that cation depletion both increases freshwater acidification and decreases forest productivity. Similarly, the same nitrogen atom that contributes to stream acidification can ultimately contribute to coastal eutrophication as it travels downstream to an estuarine environment. Therefore, to understand the full effects of atmospheric deposition, it is necessary to recognize the interactions between all of these systems.

5.2.1 Freshwater Acidification

Acid deposition causes acidification of surface waters. In the 1980s, acid rain was found to be the dominant cause of acidification in 75 percent of acidic lakes and 50 percent of acidic streams. Areas especially sensitive to acidification include portions of the Northeast (particularly the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and Southeastern streams. Some high-elevation Western lakes, particularly in the Rocky Mountains, have become acidic, especially during snowmelt. However, although many Western lakes and streams are sensitive to acidification, they are not subject to continuously high levels of acid deposition and so have not become chronically acidified (NAPAP, 1990).

ANC, a key indicator of the ability of the water and watershed soil to neutralize the acid deposition it receives, depends largely on the watershed's physical characteristics:

geology, soils, and size. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC.

As acidity increases, aluminum leached from the soil flows into lakes and streams and can be toxic to aquatic species. The lower pH levels and higher aluminum levels that result from acidification make it difficult for some fish and other aquatic species to survive, grow, and reproduce. In some waters, the number of species of fish able to survive has been directly correlated to water acidity. Acidification can also decrease fish population density and individual fish size (U.S. Department of the Interior, 2003).

Recent watershed mass balance studies in the Northeast reveal that loss of sulfate from the watershed exceeds atmospheric sulfur deposition (Driscoll et al., 2001). This suggests that these soils have become saturated with sulfur, meaning that the supply of sulfur from deposition exceeds the sulfur demands of the ecosystem. As a result, sulfur is gradually being released or leached from the watershed into the surface waters as sulfate. Scientists now expect that the release of sulfate that previously accumulated in watersheds will delay the recovery of surface waters in the Northeast that is anticipated in response to the recent SO_2 emission controls (Driscoll et al., 2001).

A major study of the ecological response to acidification is taking place in the Bear Brook Watershed in Maine. Established in 1986 as part of the EPA's Watershed Manipulation Project, the project has found that experimental additions of sulfur and nitrogen to the watershed increased the concentrations of both sulfate and nitrate in the West Bear Brook stream. Stream water concentrations of several other ions, including base cations, aluminum, and ANC, changed substantially as well (Norton et al., 1999). During the first year of treatment, 94 percent of the nitrogen added experimentally to the Bear Brook watershed was retained, while the remainder leached into streams as nitrate. Nitrogen retention decreased to about 82 percent in subsequent years (Kahl et al., 1993; 1999). Although the forest ecosystem continued to accumulate nitrogen, nitrate leaching into the stream continued at elevated levels throughout the length of the experiment. This nitrate contributed to both episodic and chronic acidification of the stream. This and other similar studies have allowed scientists to quantify acidification and recovery relationships in eastern watersheds in much more detail than was possible in 1990.

The Appalachian Mountain region receives some of the highest rates of acid deposition in the United States (Herlihy et al., 1993). The acid-base status of stream waters in forested upland watersheds in the Appalachian Mountains was extensively investigated in the early 1990s (e.g., Church et al. [1992]; Herlihy et al. [1993]; Webb et al. [1994]; van Sickle and Church [1995]). A more recent assessment of the southern Appalachian region from West Virginia to Alabama identified watersheds that are sensitive to acid deposition using geologic bedrock and the associated buffering capacity of soils to neutralize acid. The assessment found that approximately 59 percent of all trout stream length in the region is in areas that are highly vulnerable to acidification and that 27 percent is in areas that are moderately vulnerable (SAMAB, 1996). Another study estimated that 18 percent of potential brook trout streams in the mid-Appalachian Mountains are too acidic for brook trout survival (Herlihy et al., 1996). Perhaps the most important study of acid-base chemistry of streams in the Appalachian region in recent years has been the Virginia Trout Stream Sensitivity Study (Webb et al., 1994). Trend analyses of these streams indicate that few long-term sampling sites are recovering from acidification, most are continuing to acidify, and the continuing acidification is at levels that are biologically significant for brook trout populations (Webb et al., 2000).

5.2.2 Forest Ecosystems

Reductions in sulfur and nitrogen deposition under BART are expected to reduce the effects of acid deposition on forests. Our current understanding of the effects of acid deposition on forest ecosystems has come to focus increasingly on the effects of biogeochemical processes that affect plant uptake, retention, and cycling of nutrients within forested ecosystems. Research results from the 1990s indicate that documented decreases in base cations (calcium, magnesium, potassium, and others) from soils in the northeastern and southeastern United States are at least partially attributable to acid deposition (Lawrence et al., 1997; Huntington et al., 2000). Base cation depletion is a cause for concern because of the role these ions play in acid neutralization and, in the case of calcium, magnesium, and potassium, their importance as essential nutrients for tree growth. It has been known for some time that depletion of base cations from the soil interferes with the uptake of calcium by roots in forest soils (Shortle and Smith, 1988). Recent research indicates it also leads to aluminum mobilization (Lawrence et al., 1995), which can have harmful effects on fish (U.S. Department of the Interior, 2003).

The plant physiological processes affected by reduced calcium availability include cell wall structure and growth, carbohydrate metabolism, stomatal regulation, resistance to plant pathogens, and tolerance of low temperatures (DeHayes et al., 1999). Soil structure, macro and micro fauna, decomposition rates, and nitrogen metabolism are also important processes that are significantly influenced by calcium levels in soils. The importance of calcium as an indicator of forest ecosystem function is due to its diverse physiological roles, coupled with the fact that calcium mobility in plants is very limited and can be further reduced by tree age, competition, and reduced soil water supply (McLaughlin and Wimmer, 1999).

A clear link has now been established in red spruce stands between acid deposition, calcium supply, and sensitivity to abiotic stress. Red spruce uptake and retention of calcium is affected by acid deposition in two main ways: leaching of important stores of calcium from needles (DeHayes et al., 1999) and decreased root uptake of calcium due to calcium depletion from the soil and aluminum mobilization (Smith and Shortle, 2001; Shortle et al., 1997; Lawrence et al., 1997). Acid deposition leaches calcium from mesophyll cells of 1-year-old red spruce needles (Schaberg et al., 2000), which in turn reduces freezing tolerance (DeHayes et al., 1999). These changes increase the sensitivity of red spruce to winter injuries under normal winter conditions in the Northeast, result in the loss of needles, and impair the overall health of forest ecosystems (DeHayes et al., 1999). Red spruce must also expend more metabolic energy to acquire calcium from soils in areas with low calcium/aluminum ratios, resulting in slower tree growth (Smith and Shortle, 2001).

Losses of calcium from forest soils and forested watersheds have now been documented as a sensitive early indicator of the soil response to acid deposition for a wide range of forest soils in the United States (Lawrence et al., 1999; Huntington et al., 2000). There is a strong relationship between acid deposition and leaching of base cations from hardwood forest (e.g., maple, oak) soils, as indicated by long-term data on watershed mass balances (Likens et al., 1996; Mitchell et al., 1996), plot- and watershed-scale acidification experiments in the Adirondacks (Mitchell et al., 1994) and in Maine (Norton et al., 1994; Rustad et al., 1996), and studies of soil solution chemistry along an acid deposition gradient from Minnesota to Ohio (MacDonald et al., 1992).

Although sulfate is the primary cause of base cation leaching, nitrate is a significant contributor in watersheds that are nearly nitrogen saturated (Adams et al., 1997). Recent studies of the decline of sugar maples in the Northeast demonstrate a link between low base cation availability, high levels of aluminum and manganese in the soil, and increased levels of tree mortality due to native defoliating insects (Horsley et al., 2000). The chemical composition of leaves and needles may also be altered by acid deposition, resulting in changes in organic matter turnover and nutrient cycling.

5.2.3 Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. It is now known that nitrogen deposition is a significant source of nitrogen to many estuaries (Valigura et al., 2001; Howarth, 1998). The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. For a handful of estuaries, atmospheric deposition of nitrogen contributes well over 40 percent of the total nitrogen load; however, in most estuaries for which estimates exist, the contribution from atmospheric deposition ranges from 15 to 30 percent. The area with the highest deposition rates (30 percent deposition rates) stretches from Massachusetts to the Chesapeake Bay and along the central Gulf of Mexico coast.

Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. Approximately 60 percent of estuaries in the United States (65 percent of the estuarine surface area) suffer from overenrichment of nitrogen, a condition known as eutrophication (Bricker et al., 1999). Symptoms of eutrophication include changes in the dominant species of plankton (the primary food source for many kinds of marine life) that can cause algal blooms, low levels of oxygen in the water column, fish and shellfish kills, and cascading population changes up the food chain. Many of the most highly eutrophic estuaries are along the Gulf and mid-Atlantic coasts, overlapping many of the areas with the highest nitrogen deposition, but there are eutrophic estuaries in every region of the coterminous U.S. coastline.

5.2.4 Potential Other Impacts

This rule is expected to result in many categories of benefits that we are currently unable to quantify or monetize. It is possible that reductions in nitrogen deposition resulting from this rule may lessen the benefits of passive fertilization for forests and terrestrial ecosystems where nutrients are a limiting factor and for some croplands.

The effects of ozone and particulate matter on radiative transfer in the atmosphere can also lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of UVb radiation to the ground. EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively small changes in average ozone levels over the course of a year (EPA, 2005a). EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from reducing ozone-related attenuation of UVb radiation (EPA, 2005b). Sulfate and nitrate particles also scatter UVb, which can decrease exposure of horizontal surfaces to UVb, but increase exposure of vertical surfaces. In this case as well, both the magnitude and direction of the effect of reductions in sulfate and nitrate particles are too uncertain to quantify (EPA, 2004). Ozone is a greenhouse gas, and sulfates and nitrates can reduce the amount of solar radiation reaching the earth, but EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

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CHAPTER 6

PROFILE OF POTENTIALLY AFFECTED INDUSTRY SECTORS

Potential sources affected by the BART rulemaking are defined in Section 169A (g) (7) of the CAA. This section defines affected sources to be "major stationary sources" with the potential to emit 250 tons or more of any pollutant and fossil-fuel-fired steam electric plants of more than 250 million Btus per hour heat input. Additional source categories enumerated in the Act include coal cleaning plants; kraft pulp mills; Portland cement plants; primary zinc smelters; iron and steel mill plants; primary aluminum ore reduction plants; primary copper smelters; municipal incinerators; hydrofluoric, sulfuric, and nitric acid plants; petroleum refineries; lime plants; phosphate rock processing plants; coke oven batteries; sulfur recovery plants; carbon black plants; primary lead smelters; fuel conversion plants; sintering plants; secondary metal production facilities; chemical process plants; taconite ore processing facilities; glass fiber processing plants; and charcoal production facilities (see examples in Table 6-1). States implementing the BART rule must consider emission controls for any BART-eligible source operating in the previously enumerated list of applicable industries. A subset of the preceding list of industries that includes those most likely to be affected by this rulemaking are characterized in this chapter.

6.1 Power-Sector Overview

The functions of the power sector can be separated into three distinct operating activities: generation, transmission, and distribution.

6.1.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. The process of generating electricity, in most cases, involves creating heat to rotate turbines which, in turn, create electricity. The power sector consists of over 16,000 generating units, consisting of fossil-fuel fired units, nuclear units, and hydroelectric and renewable sources dispersed throughout the country (see Table 6-2).

Table 6-1. Examples of Affected Source Categories

Source Category Name	SIC	NAICS	Industry Profile Subsection
Fossil Fuel-Fired Steam Electric Plants (>250 MMBTU heat input per hour)	4911	221111, 221112, 221113, 221119, 221121, 221122	6.1 Power Sector
Fossil Fuel-Fired Industrial Boilers (>250 MMBTU heat input per hour)	NA	NA	NA
Petroleum Refineries	2911	324110	6.6 Petroleum Refining Industry
Kraft Pulp Mills	2611, 2621, 2631	322110, 322121, 322122, 322130, 322121, 322122, 322130	6.5 Paper and Allied Products
Portland Cement Plants	3241	327310	6.2 Cement
Iron and Steel Mill Plants	3312	331111, 331221	6.7 Primary Metal Manufacturing
Hydrofluoric, Sulfuric, and Nitric Acid Plants	2819	211112	6.4 Crude Petroleum and Natural Gas
Coke Oven Batteries	3312	331111, 331221	6.7 Primary Metal Manufacturing
Sulfur Recovery Plants	2819	325131, 325188, 325998, 331311	6.3 Industrial Organic Chemicals
Primary Lead Smelters	3339	331419	6.7 Primary Metal Manufacturing
Primary Copper Smelters	3331	331411	6.7 Primary Metal Manufacturing
Primary Zinc Smelters	33xx	331419	6.7 Primary Metal Manufacturing
Primary Aluminum Ore Reduction Plants	3334	331312	6.7 Primary Metal Manufacturing
Municipal Incinerators (>250 tons refuse per day)	4953	562211, 562212, 562213, 562219, 562920	NA
Lime Plants	3274	327410	NA
Phosphate Rock Processing Plants	1429	212319	NA

(continued)

Table 6-1. Examples of Affected Source Categories (continued)

Source Category Name	SIC	NAICS	Industry Profile Subsection
Carbon Black Plants (furnace process)	2895	325182	6.3 Industrial Organic Chemicals
Fuel Conversion Plants	NA	NA	NA
Sintering Plants	NA	NA	NA
Secondary Metal Production Facilities	3341	331314, 331423, 331492	6.7 Primary Metal Manufacturing
Chemical Process Plants	28xx	325	6.3 Industrial Organic Chemicals
Petroleum Storage and Transfer Facilities (capacity > 300,000 barrels)	5171, 5172	424710, 454311, 454312, 424720, 425110, 425120	6.6 Petroleum Refining Industry
Taconite Ore Processing Plants	3295	212324, 212325, 212393, 212399, 327992	NA
Glass Fiber Processing Plants	32xx	327212	NA
Charcoal Production Facilities	2819	211112, 325131, 325188, 325998, 331311	6.3 Industrial Organic Chemicals
Coal Cleaning Plants (thermal dryers)	2999	324199	NA

Table 6-2. Existing Electricity Generating Capacity by Energy Source, 2002

Energy Source	Number of Generators	Generator Nameplate Capacity (MW)
Coal	1,566	338,199
Petroleum	3,076	43,206
Natural Gas	2,890	194,968
Dual Fired	2,974	180,174
Other Gases	104	2,210
Nuclear	104	104,933
Hydroelectric	4,157	96,343
Other Renewables	1,501	18,797
Other	41	756
Total	**16,413**	**979,585**

Source: EIA

These electric-generating sources provide electricity for commercial, industrial, and residential uses, each of which consumes roughly one-third of the total electricity produced (see Table 6-3).

Table 6-3. Total U.S. Electric Power Industry Retail Sales in 2003 (Billion kWh)

	N	%
Residential	1,280	37%
Commercial	1,119	32%
Industrial	991	28%
Other	109	3%
All Sectors	**3,500**	**100%**

Source: EIA

In 2003, electric-generating sources produced 3,848 billion kWh to meet electricity demand. Roughly 70 percent of this electricity was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for more than half of the total (see Table 6-4).

Table 6-4. Electricity Net Generation in 2003 (Billion kWh)

	N	%
Coal	1,970	51%
Petroleum	118	3%
Natural Gas	629	16%
Other Gases	11	0.3%
Nuclear	764	20%
Hydroelectric	275	7%
Other	81	2%
Total	**3,848**	**100%**

Source: EIA

Note: Retail sales and net generation may not correspond exactly because net generation data may include net exported electricity and loss of electricity.

Coal-fired generating units typically supply “base-load” electricity, which means these units operate continuously throughout the day. Coal-fired generation, along with nuclear generation, meet the part of demand that is relatively constant. Gas-fired generation, however, typically supplies “peak” power, when there is increased demand for electricity (e.g., when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning, versus late at night or very early morning when demand for electricity is reduced).

6.1.2 Transmission

Transmission is the term used to describe the movement of electricity, through use of high voltage lines, from electric generators to substations where power is stepped down for local distribution. Transmission systems have been traditionally characterized as a collection of independently operated networks or grids interconnected by bulk transmission interfaces.

Within a well-defined service territory, the regulated utility has historically had responsibility for all aspects of developing, maintaining, and operating transmission of electricity. These responsibilities typically included system planning and expanding, maintaining power quality and stability, and responding to failures.

6.1.3 Distribution

Distribution of electricity involves networks of smaller wires and substations that take the higher voltage from the transmission system and step it down to lower levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly because it is not practical to have more than one set of lines running from the electricity-generating sources to neighborhoods or from the curb to the house.

Transmission and distribution have been considered differently than generation in current efforts to restructure the industry. Transmission has generally been developed by the larger vertically integrated utilities that typically operate generation and distribution networks. Distribution is handled by a large number of utilities that often only sell electricity. Electricity restructuring has focused primarily on converting the industry to fully compete the sale of electricity production or generation and not the transmission or distribution of electricity. The restructuring of the industry is, in large part, the separating of generation assets from the transmission and distribution assets into separate economic entities in many State efforts. Transmissions and distribution remain price regulated throughout the country based on the cost of service.

6.1.4 Deregulation and Restructuring

The ongoing process of deregulation of wholesale and retail electric markets is changing the structure of the electric power industry. In addition to reorganizing asset management between companies, deregulation is aimed at the functional unbundling of generation, transmission, distribution, and ancillary services the power sector has historically provided to competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation, communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the possibility of lower electric rates, reduced costs of combustion turbine technology that opened the door for more companies to sell power, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes (see Figure 6-1). The pace of restructuring in the electric power industry slowed significantly in response to market volatility and financial turmoil associated with bankruptcy filings of key energy companies in California. By the end of 2001, restructuring had either been delayed or suspended in eight states that previously enacted legislation or issued regulatory orders for its implementation. Another 18 other states that had seriously explored the possibility of deregulation in 2000 reported no legislative or regulatory activity in 2001 (DOE, EIA, 2003a). Currently, there are 17 states where price deregulation of generation (restructuring) has occurred. The effort is more or less at a standstill; however, at the federal level, there are efforts in the form of proposed legislation and proposed Federal Energy Regulatory Commission (FERC) actions aimed at reviving restructuring. For states that have not begun restructuring efforts, it is unclear when and at what pace these efforts will proceed.

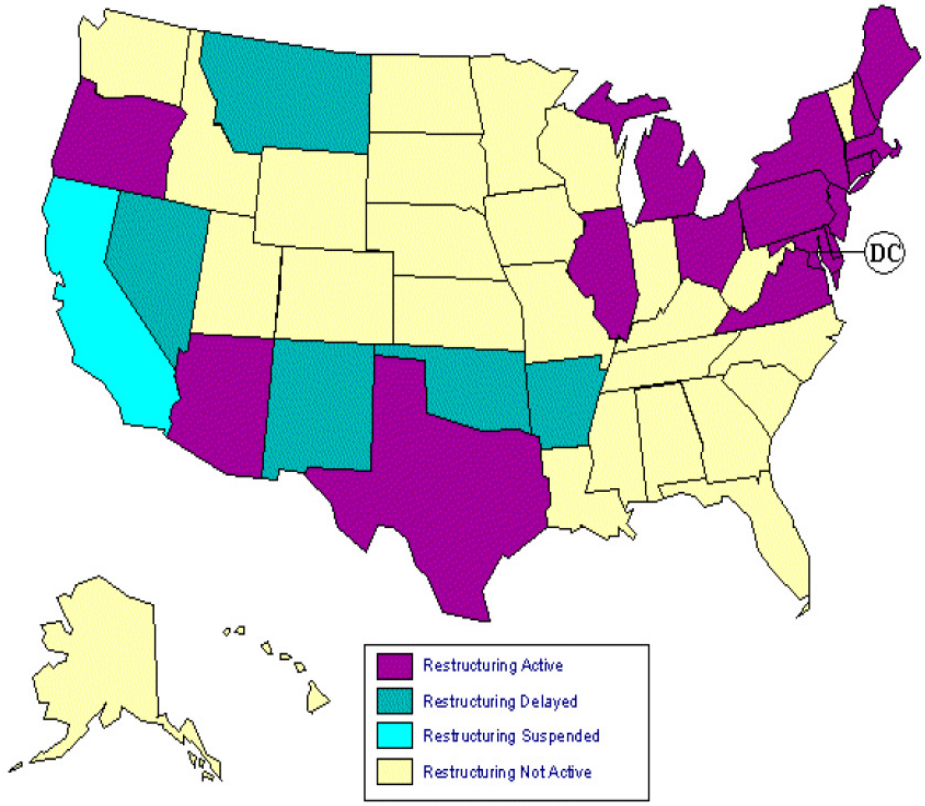

Figure 6-1. Status of State Electricity Industry Restructuring Activities (as of February 2003)

6.1.5 Pollution and EPA Regulation of Emissions

The burning of fossil fuels, which generates about 70 percent of our electricity nationwide, results in air emissions of SO_2 and NO_x, important precursors in the formation of fine particles and ozone (NO_x only) and to visibility impairment. In 2003, the power sector accounted for 67 percent of total nationwide SO_2 emissions and 22 percent of total nationwide NO_x emissions (see Figure 6-2).

Different types of fossil fuel-fired units vary widely in their air emissions levels for SO_2 and NO_x, particularly when uncontrolled. For coal-fired units, NO_x emission rates can vary from under 0.05 lbs/mmBtu (for a unit with selective catalytic reduction for NO_x removal) to over 1 lb/mmBtu for an uncontrolled cyclone boiler. NO_x emissions from

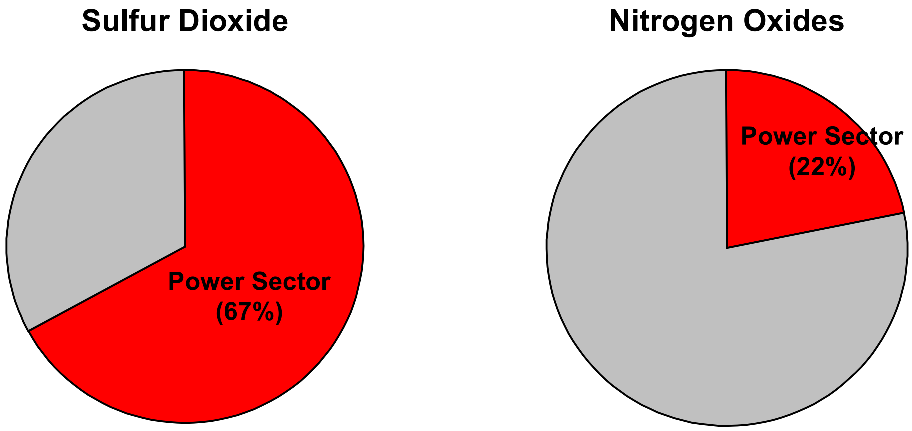

Figure 6-2. Emissions of SO_2 and NO_x from the Power Sector (2003)

coal-fired power plants are formed during combustion and are a result of both nitrogen in coal and nitrogen in the air. SO_2 emission rates can vary from under 0.1 lbs/mmBtu (for some units with flue gas desulfurization for SO_2 removal) to over 5 lbs/mmBtu for units burning higher sulfur coal. For an uncontrolled coal plant, SO_2 emissions are directly related to the amount of sulfur in the coal.

Oil- and gas-fired units also have a wide range of NO_x emissions depending on both the plant type and the controls installed. Units with selective catalytic reduction (SCR) can have emission rates under 0.01 lbs/mmBtu, while completely uncontrolled units can have emission rates in excess of 0.5 lbs/mmBtu. Gas-fired units have very little SO_2 emissions. NO_x emission rates on oil-fired units can range from under 0.1 lbs/mmBtu (for units with new combustion controls) to over 0.6 lbs/mmBtu for units without combustion controls. SO_2 emissions for oil-fired units can range from under 0.1 lbs/mmBtu for units burning low sulfur distillate oil to over 2 lbs/mmBtu for units burning high sulfur residual oil.

6.1.6 Pollution Control Technologies

There are two primary options for reducing SO_2 emissions from coal-burning power plants. Units may switch from higher to lower sulfur coal, or they may use flue gas desulfurization (FGD, commonly referred to as scrubbers). According to data submitted to EPA for compliance with the Title IV Acid Rain Program, the SO_2 emission rates for coal-fired units varied from under 0.4 lbs/mmBtu to over 5 lbs/mmBtu depending on the type of coal combusted.

It is generally easier to switch to a coal within the same rank (e.g., bituminous or subbituminous) because these coals will have similar heat contents and other characteristics. Switching completely to subbituminous coal (which typically has a lower sulfur content) from bituminous coal is likely to require some modifications to the unit. Limited blending of subbituminous coal with bituminous coal can often be done with much more limited modifications.

The two most commonly used scrubber types are wet scrubbers and spray dryers. Wet scrubbers can use a variety of sorbents to capture SO_2 including limestone and magnesium-enhanced lime. The choice of sorbent can affect the performance, size, and capital and operating costs of the scrubber. New wet scrubbers typically achieve at least 95 percent SO_2 removal. Spray dryers can achieve over 90 percent removal.

One method of reducing NO_x emissions is using combustion controls (such as low NO_x burners and over-fired air). Combustion controls reduce NO_x by ensuring that the combustion of coal occurs under conditions under which less formation of NO_x occurs. Postcombustion controls reduce NO_x by removing the NO_x after it has been formed. The most common postcombustion control is SCR. SCR systems inject ammonia (NH_3), which combines with the NO_x in the flue gas, to form nitrogen and water and uses a catalyst to enhance the reaction. These systems can reduce NO_x by 90 percent and achieve emission rates of around 0.06 lbs/mmBtu. Selective noncatalytic reduction also removes NO_x by injecting ammonia, but no catalyst is used. These systems can reduce NO_x by up to 40 percent.

For more detail on the cost and performance assumptions of pollution controls, see the documentation for the Integrated Planning Model (IPM), a dynamic linear programming model that EPA uses to examine air pollution control policies for SO_2 and NO_x throughout the contiguous United States for the entire power system. Documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm.

6.1.7 Regulation of the Power Sector

At the federal level, efforts to reduce emissions of SO_2 and NO_x have been occurring since 1970. Policy makers have recognized the need to address these harmful emissions, and incremental steps have been taken to ensure that the country meets air quality standards.

Federal regulation of SO_2 and NO_x emissions at power plants began with the 1970 CAA. The Act required the Agency to develop performance standards for a number of source categories including coal-fired power plants. The first New Source Performance Standards (NSPS) for power plants (subpart D) required new units to limit SO_2 emissions either by using scrubbers or by using low-sulfur coal. NO_x was required to be limited through the use of low NO_x burners. A new NSPS (subpart Da), promulgated in 1978, tightened the standards for SO_2 requiring scrubbers on all new units.

The 1990 Clean Air Act Amendments (CAAA) placed a number of new requirements on power plants. The Acid Rain Program, established under Title IV of the 1990 CAAA, requires major reductions of SO_2 and NO_x emissions. The SO_2 program sets a permanent cap on the total amount of SO_2 that can be emitted by electric power plants in the contiguous United States at about one-half of the amount of SO_2 these sources emitted in 1980. Using a market-based cap-and-trade mechanism allows flexibility for individual combustion units to select their own methods of compliance. The program uses a more traditional approach to NO_x emission limitations for certain coal-fired electric utility boilers, with the objective of achieving a 2 million ton reduction from projected NO_x emission levels that would have been emitted in 2000 without implementation of Title IV.

The Acid Rain Program comprises two phases for SO_2 and NO_x. Phase I applied primarily to the largest coal-fired electric generation sources from 1995 through 1999 for SO_2 and from 1996 through 1999 for NO_x. Phase II for both pollutants began in 2000. For SO_2, it applies to thousands of combustion units generating electricity nationwide; for NO_x it generally applies to affected units that burned coal during 1990 through 1995. The Acid Rain Program has led to the installation of a number of scrubbers on existing coal-fired units as well as significant fuel switching to lower-sulfur coals. Under the NO_x provisions of Title IV, most existing coal-fired units were required to install low NO_x burners.

The CAAA also placed much greater emphasis on controlling NO_x to reduce ozone nonattainment. This has led to the formation of several regional NO_x trading programs and an intrastate NO_x trading program in Texas. The Ozone Transport Commission (a group of northeast states) created an interstate NO_x trading program that began in 1999. In 1998, EPA promulgated regulations (the NO_x SIP Call) that required 21 states in the eastern United States and the District of Columbia to reduce NO_x emissions that contributed to nonattainment in downwind states using the cap-and-trade approach. This program began in the summer of 2004 and has resulted in the installation of significant amounts of SCR.

In addition to federal programs to reduce emissions of SO_2 and NO_x, several states have also taken action. Several states, like North Carolina, New York, Connecticut, and Massachusetts, have moved to control these emissions to address nonattainment.

6.2 Cement

The product that most Americans know simply as cement is technically referred to as Portland cement. This product received its name because it resembled the well-known building stone quarried on the Isle of Portland in the English Channel in color and texture. Portland cement is used predominantly in the production of concrete. In 2002, the United States produced 85 million metric tons of Portland cement, while U.S. producers shipped 113 million metric tons. The total value of Portland cement shipments was $8.5 billion with an average value of $77 per metric ton shipped.

6.2.1 The Supply Side: Production and Costs

6.2.1.1 Production Process

The Portland cement manufacturing process consists of

- quarrying and crushing the raw materials,
- grinding the carefully proportioned materials to a high degree of fineness,
- firing the raw materials mixture in a rotary kiln to produce clinker, and
- grinding the resulting clinker to a fine powder and mixing with gypsum to produce cement.

There are basically two distinct methods of blending the raw mixture: the wet process and the dry process. In the wet process, water is added to the materials to create a slurry that is fed into the kiln. The water eventually is evaporated in the kiln where the raw materials are converted into clinker. In the dry process, all grinding and blending are done with dry materials that are fed directly into the kiln to be calcined into clinker. In 2001, wet process kilns produced 18.5 percent of clinker produced in the United States, dry process kilns produced 75.2 percent of clinker, and active kilns using both processes accounted for the remaining 6.5 percent (van Oss, 2002).

6.2.1.2 Types of Output

Although five basic types of Portland cement are produced in the United States, Types I and II cement are the most common type of cement shipped from U.S. plants, comprising over 85 percent of total Portland cement production in 2001 (van Oss, 2002). A brief description of each type is provided below.

Type I: Regular Portland cements are the usual products used in general concrete construction, most commonly known as gray cement because of its color. Type I is provided as a concrete without special properties. In contrast, white cement typically contains less ferric oxide and is used for special applications. Other types of regular cements include oil-well cement, quick-setting cement, and others for special uses.

Type II: Moderate heat-of-hardening and sulfate-resisting Portland cements are intended for use when moderate heat of hydration is required or for general concrete construction exposed to moderate sulfate action.

Type III: High early strength cements are made from raw materials with a lime-to-silica ratio higher than that of Type I cement and are ground finer than Type I cements. They contain a higher proportion of tricalcium silicate than regular Portland cements.

Type IV: Low-heat Portland cements contain a lower percentage of tricalcium silicate and tricalcium aluminate than Type I, thus lowering the heat evolution. Consequently, the percentage of tetracalcium aluminoferrite is increased. Type IV cements are produced to attain a low heat of hydration.

Type V: Sulfate-resisting Portland cements are those that, by their composition or processing, resist sulfates better than the other four types.

The use of additives, or admixtures, allows producers to alter or enhance the attributes of the cement product and, thus, the ultimate concrete product. Admixtures affect factors such as durability, appearance, versatility, and cost-effectiveness by altering the hydration of Portland cement in some way, by changing the speed of reaction, or by dispersing the cement particles more thoroughly throughout the concrete mix.

6.2.1.3 Production Costs

There are five primary variable inputs in cement production—labor, fuel, electricity, raw material, and maintenance. Labor is used in the quarry and for packing operations and accounts for approximately 20 percent of production costs (see Table 6-5). Fuel is largely consumed by the kilns, and inputs include coal, coke, petroleum coke, and oil. Electricity is consumed by the auxiliary equipment, and in 2001 plants used approximately 144 kilowatt-hours of electricity per ton of cement produced (van Oss, 2002). Raw materials serve as the kiln feed and account for 60 percent of material costs reported by the Bureau of the Census. The USGS estimates approximately 1.7 metric tons of nonfuel raw materials are needed to make 1 metric ton of Portland cement (van Oss, 2002). The cement industry's capital expenditures increased in 2000 and 2001 as several plants completed capacity upgrades.

Table 6-5. Costs of Production for the Cement Industry: 1997–2001

	Labor		Fuel, Electricity, and Materials	Capital Expenditures
Year	Quantity (10^3)	Payroll (\$$10^6$)	(\$$10^6$)	(\$$10^6$)
1997	16.9	734.2	2,475.8	505.6
1998	17.2	756.3	2,528.9	525.4
1999	17.3	815.7	2,526.6	691.2
2000	17.2	829.5	2,589.7	1,108.0
2001	17.2	860.5	2,724.5	1,430.0

Source: U.S. Department of Commerce, Bureau of the Census. 1997. *1997 Economic Census. Manufacturing Industry Series. Cement Manufacturing*. Washington, DC: Government Printing Office.

6.2.2 The Demand Side

Concrete and reinforced concrete are used extensively in almost all construction applications including homes, public buildings, roads, industrial plants, dams, bridges, and many other structures. Therefore, the demand for Portland cement is a derived demand, and the rate of growth in demand for Portland cement largely depends on the rate of growth in construction activities. Cement competes with other construction productions such as glass, aluminum, steel, and asphalt. The USGS reports that ready-mixed concrete producers consumed 75 percent of cement sales in 2002, followed by concrete product manufacturers (13 percent), contractors (6 percent), and other (6 percent) (van Oss, 2003).

6.2.3 Industry Organization: Market Structure, Plants, and Firms

Making inferences about the behavior of producers often requires assessing barriers to entry and developing a measure of concentration within each market, both of which should reflect the ability of firms to raise prices above the competitive level. Markets with barriers to entry (e.g., licenses, legal restrictions, or high fixed costs) are generally expected to be less competitive than those without such barriers. In addition, less concentrated markets are predicted to be more competitive and should result in a low value of the concentration measure, while a higher value should indicate a higher price-cost margin or a higher likelihood of noncompetitive behavior on the part of producers. Based on the evidence presented below, the Agency used an economic model with oligopolistic market structure to evaluate the economic impacts of recent air pollution regulations for the industry (EPA, 1999a).

Portland cement plants operate under conditions of high, location-specific fixed costs and substantial returns to scale that act as a barrier to entry. The capital investment required for the production of cement involves using large rotary kilns that are not readily movable or transferable to other uses. Because the minimum efficient scale of cement operations is a significant share of local demand, each regional Portland cement market can sustain only a small number of firms that are able to earn positive profits without inviting entry. Entry is expected to occur only in the event of growth in the local demand for Portland cement. Although a substantial portion of the cement consumed domestically is imported into the nation each year (approximately 20 percent in 2003), imports tend to fill the gap between domestic production and fluctuating demand. However, the cost and availability of shipping for cement imports does provide a substantial barrier to entry into this market (Portland Cement Association, 2005).

National measures of concentration do not suggest the cement industry is particularly concentrated. Census data (U.S. Census Bureau, 2001) show that the top four companies account for 33 percent of cement sales, and the Herfindahl-Hirschman index (HHI) is only 466. However, closer examination of the regional nature of the cement industry suggests these markets are concentrated and increases the likelihood that firms can raise prices above the competitive levels.

The Portland cement industry is characterized by regional markets because of the low value of Portland cement and the high transportation costs. Because Portland cement is generally regarded as a homogeneous product, buyers are prevented from distinguishing between the product of sellers in the market so that the geographic boundaries of each market are solely determined by the costs of transporting the Portland cement. A study of 25 regional cement markets in the United States over an 8-year period found that all of the regional markets were in fact concentrated (Iwand and Rosenbaum, 1991).

In 2001, approximately 40 companies and one state agency produced cement at 115 plants. Eight of the top 10 U.S. manufacturers are now owned by foreign companies. Texas, Pennsylvania, Michigan, Missouri, and Alabama are the largest cement-producing states, accounting for approximately 50 percent of U.S. production.

Cement plants have operated at nearly full "practicable" capacity over the past 5 years with utilization rates near 90 percent (see Table 6-6). Although the utilization rate for 2001 fell to 80 percent, this is primarily the result of new cement capacity added late in the year and temporary reductions in production resulting from technical problems at a cement plant in Colorado (van Oss, 2002).

Table 6-6. Capacity Utilization Rates: 1997–2001

Year	Percentage of Clinker Capacity Used
1997	89.4
1998	90.1
1999	88.5
2000	87.5
2001	80.0

Source: Minerals Yearbook: Volume I.—Metals and Minerals: Cement http://minerals.usgs.gov/minerals/pubs/commodity/cement/index.html#myb. Last updated October 2003.

6.2.4 Markets and Trends

U.S. production of Portland and masonry cement grew from 84 million metric tons in 1998 to 89 million metric tons in 2002 (see Table 6-7). Although consumption fell slightly from 2001 levels, it has remained at approximately 110 million metric tons over the past 3 years. The United States has relied on foreign imports from foreign countries to meet demand with approximately 20 percent of consumed cement being provided from outside the United States. Canada has been a traditional source of imports, but Asian countries such as Thailand and China have recently become important sources of cement. In contrast, little

Table 6-7. Cement Market Statistics 1998–2002 (10^3 Metric Tons, Unless Otherwise Noted)

	1998	1999	2000	2001	2002
Production:					
Portland and masonry cement	83,931	85,952	87,846	88,900	89,000
Clinker	74,523	76,003	78,138	78,451	82,000
Shipments to final customers, includes exports	103,696	108,862	110,048	113,136	110,000
Imports of hydraulic cement for consumption	19,878	24,578	24,561	23,591	22,500
Imports of clinker for consumption	3,905	4,164	3,673	1,884	1,660
Exports of hydraulic cement and clinker	743	694	738	746	900
Consumption, apparent	103,457	108,862	110,470	112,710	110,000
Price, average mill value, dollars per ton	76.46	78.27	78.56	76.50	77.00
Stocks, mill, year end	5,393	6,367	7,566	6,600	7,600
Employment, mine and mill, number	17,900	18,000	18,000	18,000	18,000
Net import reliance as a percentage of apparent consumption	19	21	20	21	19

Source: van Oss, H. 2003. Mineral Commodity Summaries: Cement. http://minerals.usgs.gov/minerals/pubs/commodity/cement/170303.pdf. Last updated January 2003.

cement is exported (less than 1 million metric tons) because of high transportation costs. Prices for cement have ranged from $76 to $78 per metric ton during this period.

The USGS has identified three key trends for the U.S. cement industry (van Oss, 2003). First, the international cement industry has experienced widespread consolidation in the last few years. In 2001, three significant ownership changes took place in the United States. Lafarge merged with Blue Circle cement and became the largest cement producer in the United States. The biggest Brazilian cement producer also entered the U.S. market with the purchase of St. Mary's Cement Corporation, and a Mexican cement firm purchased Decotah Cement from the state of South Dakota. Second, the industry continues to face environmental concerns related to emissions resulting from cement production. As a result, the industry will continue to focus on emission reduction strategies. Finally, the USGS reports that the use of natural and synthetic substitutes for Portland cement are growing outside of the United States. These materials have some performance advantages in some applications and can lower energy and related environmental costs.

6.3 Industrial Organic Chemicals

The industrial organic chemicals (not elsewhere classified) industry (NAICS 3251) produces organic chemicals for end-use applications and for inputs into numerous other chemical manufacturing industries. In nominal terms, it was the single largest segment of the $419 billion chemical manufacturing industry (NAICS 325) in 1997, accounting for approximately 27 percent of the industry's shipments.

All organic chemicals are, by definition, carbon based and are divided into two general categories: commodity and specialty. Commodity chemical manufacturers compete on price and produce large volumes of staple chemicals using continuous manufacturing processes. Specialty chemicals cater to custom markets, using batch processes to produce a diverse range of chemicals. Specialty chemicals generally require more technical expertise and research and development than the more standardized commodity chemicals industry (EPA, 2002b). Consequently, specialty chemical manufacturers have a greater value added to their products. End products for all industrial organic chemical producers are as varied as synthetic perfumes, flavoring chemicals, glycerin, and plasticizers.

6.3.1 The Supply Side: Production and Costs

6.3.1.1 Production Processes

Processes used to manufacture industrial organic chemicals are as varied as the end products themselves. There are thousands of possible ingredients and hundreds of processes. Therefore, the discussion that follows is a general description of the ingredients and stages involved in a typical manufacturing process.

Essentially a set of ingredients (feedstocks) is combined in a series of reactions to produce end products and intermediates (EPA, 2002b). The typical chemical synthesis processes incorporate multiple feedstocks in a series of chemical reactions. Commodity chemicals are produced in a continuous reactor, and specialty chemicals are produced in batches. Specialty chemicals may undergo a series of reaction steps, as opposed to commodity chemicals' one continuous reaction because a finite amount of ingredients is prepared and used in the production process. Reactions usually take place at high temperatures, with one or two additional components being intermittently added. As the production advances, by-products are removed using separation, distillation, or refrigeration techniques. The final product may undergo a drying or pelletizing stage to form a more manageable substance.

6.3.1.2 Types of Output

Miscellaneous industrial organic chemicals comprise nine general categories of products:

- aliphitic and other acyclic organic chemicals (ethylene); acetic, chloroaceptic, adipic, formic, oxalic, and tartaric acids and their metallic salts; chloral, formaldehyde, and methylamine;
- solvents (ethyl alcohol etc.); methanol; amyl, butyl, and ethyl acetates; ethers; acetone, carbon disulfide, and chlorinated solvents;
- polyhydric alcohols (e.g., synthetic glycerin);
- synthetic perfume and flavoring materials (e.g., citral, methyl, oinone);
- rubber processing chemicals, both accelerators and antioxidants (cyclic and acyclic);
- cyclic and acyclic plasticizers (e.g., phosphoric acid);
- synthetic tanning agents;
- chemical warfare gases; and
- esters, amines, etc., of polyhydric alcohols and fatty and other acids.

6.3.1.3 Major By-Products and Co-Products

By-products, co-products, and emissions vary according to the ingredients, processes, maintenance practices, and equipment used (EPA, 2002b). Frequently, residuals from the reaction process that are separated from the end product are resold or possibly reused in the manufacturing process. A by-product from one process may be another's input. The industry is strictly regulated because it emits chemicals through many types of media, including discharges to air, land, and water, and because of the volume and composition of these emissions.

6.3.1.4 Production Costs

Of all the factors of production, employment in industrial organic chemicals fluctuated the least between 1997 and 2001 (see Table 6-8). During that time, the nominal cost of materials rose 10.7 percent to \$66 billion, reaching a low of \$53 billion in 1998. Between 1987 and 1996, employment decreased 7 percent, and this decrease continued between 1997 and 2001. Facilities became far more computerized, incorporating advanced technologies into the production process. Even with the drop in employment, payroll was \$300 million more in 2001 than in 1997. The cost of materials fluctuated between \$29 and \$36 billion for these years, and new capital investment averaged \$109 billion a year.

Table 6-8. Inputs for the Industrial Organic Chemicals Industry (NAICS 3251), 1997–2001

	Labor			
Year	Quantity (10^3)	Payroll (\$$10^6$)	Materials (\$$10^6$)	Capital Expenditures (\$$10^6$)
1997	200.8	10,290.9	59,632.4	113,356.9
1998	202.2	10,498.4	53,294.7	106,695.1
1999	196.6	10,504.8	58,090.9	106,288.5
2000	190.8	10,530.8	69,948.1	115,707.6
2001	183.2	10,582.4	66,020.6	104,430.2

Source: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures, 2001*. Washington, DC: Government Printing Office.

6.3.2 The Demand Side

Industrial organic chemicals are components of many chemical products. Most of the chemical sectors (classified under NAICS 325) are downstream users of organic chemicals. These sectors either purchase commodity chemicals or enter into contracts with industrial organic chemical producers to obtain specialty chemicals. Consumers include inorganic chemicals (NAICS 3251), plastics and synthetics (NAICS 3252), drugs (NAICS 3254), soaps and cleaners (NAICS 3256), paints and allied products (NAICS 3251), and miscellaneous chemical products (NAICS 3259).

6.3.3 *Organization of the Industry: Market Concentration, Plants, and Firms*

The industrial organic chemicals industry is unconcentrated. The NAICS 3251 1997 four-firm concentration ratio (CR4) was 15.6 and the eight-firm concentration ratio (CR8) was 28.7; the industry's HHI was 156.4. Facilities with 100 or more employees continued to account for the majority of the industry's shipment values. For example, in 1992, 28 percent of all facilities had 100 or more employees (see Table 6-9), and these facilities produced 89 percent of the industry's shipment values. The average number of facilities per firm was 1.4 in both years. Unfortunately, there is no direct correspondence between SIC 2869 and a six-digit NAICS code industry. The 1997 Economic Census Manufacturing Series does not present the same information as given in Table 6-9 for NAICS 3251. Table 6-10 instead presents establishment sizes for the two largest subsectors of NAICS 3251. NAICS 325110 encompasses the petrochemical manufacturing industry, and NAICS 325199 represents manufacturing of all other basic organic chemicals.

Table 6-9. Historical Size of Establishments and Value of Shipments for the Industrial Organic Chemicals Industry (SIC 2869/NAICS 3251)

	1987		1992	
Number of Employees in Establishment	**Number of Facilities**	**Value of Shipments (1992 $\$10^6$)**	**Number of Facilities**	**Value of Shipments (1992 $\$10^6$)**
1 to 4 employees	97	552.8	100	102.6
5 to 9 employees	80	200.9	80	208.7
10 to 19 employees	91	484.7	97	533.9
20 to 49 employees	137	1,749.9	125	1,701.5
50 to 99 employees	99	2556.3	106	3,460.9
100 to 249 employees	110	10,361.2	111	8,855.9
250 to 499 employees	41	17,156.9	41	9,971.1
500 to 999 employees	27	9,615.5	30	13,755.0
1,000 to 2,499 employees	11	9,184.6	10	9,051.0
2,500 or more employees	6	7,156.9	5	6,613.5
Total	699	59,019.7	705	54,254.1

Sources: U.S. Department of Commerce, Bureau of the Census. 1995. *1992 Census of Manufactures, Industry Series: Industrial Organic Chemicals*. Washington, DC: Government Printing Office.

U.S. Department of Commerce, Bureau of the Census. 1990. *1987 Census of Manufactures, Industry Series, Industrial Organic Chemicals*. Washington, DC: Government Printing Office.

Table 6-10. 1997 Size of Establishments, Value of Shipments, and Payroll for the Industrial Organic Chemicals Industry (NAICS 3251)

	NAICS 325110		NAICS 325199	
Number of Employees in Establishment	**Number of Facilities**	**Value of Shipments ($\$10^6$)**	**Number of Facilities**	**Value of Shipments ($\$10^6$)**
1 to 4 employees	4	3.3	111	178.4
5 to 9 employees	2	D	60	321.2
10 to 19 employees	5	26.0	80	844.9
20 to 49 employees	5	101.1	136	2,211.7
50 to 99 employees	10	866.9	100	4,364.9
100 to 249 employees	13	2,669.1	118	10,905.4
250 to 499 employees	9	5,211.0	33	7,592.2
500 to 999 employees	5	D	25	12,695.8
1,000 to 2,499 employees	1	D	12	D
2,500 or more employees	—	—	1	D
Total	54	20,534.8	676	53,542.4

D = undisclosed

Source: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census. Manufacturing Industry Series. All Other Basic Organic Chemical Manufacturing*. Washington, DC: Government Printing Office.

U.S. Department of Commerce, Bureau of the Census. 1999b. *1997 Economic Census. Manufacturing Industry Series. Petrochemical Manufacturing*. Washington, DC: Government Printing Office.

6.3.3.1 Capacity Utilization

The capacity utilization ratio for the industry averaged 78 over the 5-year period presented. The varying capacity utilization ratios within this industry reflect changes in production volumes and new production facilities and capacities going on- and off-line between 1997 and 2001 (see Table 6-11).

Table 6-11. Capacity Utilization Ratios for the Industrial Organic Chemicals Industry (NAICS 3251), 1997–2001

	1997	1998	1999	2000	2001
NAICS 3251	83	80	82	76	69

Note: All values are percentages.

Source: U.S. Department of Commerce, Bureau of the Census. 2003b. *Current Industrial Reports, Survey of Plant Capacity: 2001* Washington, DC: Government Printing Office.

6.3.4 Markets and Trends

The inorganic chemicals industry's shipments rose in 2000 to a high of $115.7 billion before declining in 2001, as seen in Table 6-12. Between 1997 and 2001, the industry's shipments fell 7.9 percent to $104.4 billion. This decrease largely reflects the downturn in petrochemical production and reduced exports due to the Asian financial crisis (Saftlas, 1999).

Table 6-12. Value of Shipments for the Industrial Organic Chemicals, N.E.C. Industry (SIC 2869/NAICS 3251), 1997–2001

Year	Value of Shipments ($\$10^6$)
1997	113,356.9
1998	106,695.1
1999	106,288.5
2000	115,707.6
2001	104,430.2

Source: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures, 2001*. Washington, DC: Government Printing Office.

The U.S. industrial organic chemical industry is expected to expand through 2004 at an annual rate of 3 percent (Saftlas, 1999). U.S. producers face increasing competition domestically and abroad as chemical industries in developing nations gain market share and increase exports to the United States. In the coming years, the United States is expected to remain a net exporter of industrial organic chemicals, but this surplus will decrease with increased global competition.

6.4 Crude Petroleum and Natural Gas

The crude petroleum and natural gas industry encompasses the oil and gas extraction process from the exploration for oil and natural gas deposits through the transportation of the product from the production site (NAICS 211 and 213). The primary products of this industry are natural gas, natural gas liquids (NGLs), and crude petroleum.

6.4.1 The Supply Side: Production and Costs

6.4.1.1 Production Processes

Domestic production occurs within the contiguous 48 U.S., Alaska, and at offshore facilities. There are four major stages in oil and gas extraction: exploration, well development, production, and site abandonment (EPA, 2000). Exploration is the search for rock formations associated with oil and/or natural gas deposits. Certain geological clues, such as porous rock with an overlying layer of low-permeability rock, help guide exploration companies to possible sources.

After a field is located, the well development process begins. Well holes, or well bores, are drilled to a depth of between 1,000 and 30,000 feet, with an average depth of about 5,500 feet (EPA, 2000). As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. Once the well has been drilled, rigging, derricks, and other production equipment are installed. Onshore fields are equipped with a pad and roads; ships, floating structures, or a fixed platform are procured for offshore fields. The hydrocarbons are brought to the surface and are separated into a spectrum of products.

6.4.1.2 Types of Output

The oil and gas industry's principal products are crude oil, natural gas, and NGLs Refineries process crude oil into several petroleum products. These products include motor gasoline (40 percent of crude oil); diesel and home heating oil (20 percent); jet fuels (10 percent); waxes, asphalts, and other nonfuel products (5 percent); feedstocks for the petrochemical industry (3 percent); and other lesser products (EPA, 2000).

Natural gas is produced from either oil wells (known as "associated gas") or wells that are drilled for the primary objective of obtaining natural gas (known as "nonassociated gas"). Methane is the predominant component of natural gas (about 85 percent), but ethane (about 10 percent), propane, and butane are also components. Propane and butane, the heavier components of natural gas, exist as liquids when cooled and compressed. These latter two components are usually separated and processed as NGLs (EPA, 2000). A small amount of the natural gas produced is consumed as fuel by the engines used in extracting and transporting the gas, and the remainder is transported through pipelines for use by residential, commercial, industrial, and electric utility users.

6.4.1.3 Major By-products

In addition to the various products of the oil and natural gas extraction process described above, some additional by-products are generated during the extraction process. Oil and natural gas are composed of widely varying constituents and proportions depending on the site of extraction. The removal and separation of individual hydrocarbons during processing is possible because of the differing physical properties of the various components. Each component has a distinctive weight, boiling point, vapor pressure, and other characteristics, making separation relatively simple. Most natural gas is processed to separate hydrocarbon liquids that are more valuable as separate products, such as ethane, propane, butane, isobutane, and natural gasoline. Finally, the engines that provide pumping action at wells and push crude oil and natural gas through pipes to processing plants, refineries, and storage locations produce HAPs. HAPs produced in engines include formaldehyde, acetaldehyde, acrolein, and methanol.

6.4.1.4 Production Costs

Automation, mergers, and corporate downsizing have made this industry less labor intensive (Lillis, 1998). As shown in Table 6-13, the latest census data show labor costs account for only 8 percent of production costs. Material costs (including fuel and electricity) accounted for approximately 60 percent; the vast majority of these expenditures are for materials and supplies. Capital expenditures accounted for the remaining 32 percent.

6.4.2 Demand-Side Characteristics

Crude oil, or unrefined petroleum, is a complex mixture of hydrocarbons that is the most important of the primary fossil fuels. Refined petroleum products are used for petrochemicals, lubrication, heating, and fuel. Petrochemicals derived from crude oil are the source of chemical products such as solvents, paints, plastics, synthetic rubber and fibers, soaps and cleansing agents, waxes, jellies, and fertilizers. Petroleum products also fuel the engines of automobiles, airplanes, ships, tractors, trucks, and rockets. Other applications include fuel for electric power generation, lubricants for machines, heating, and asphalt (EPA, 1995c).

Table 6-13. Costs of Production for the Crude Petroleum and Natural Gas Industry: 1997

NAICS	Labor		Fuel, Electricity, and Materials ($\$10^6$)	Capital Expenditures ($\$10^6$)
	Quantity (10^3)	Payroll ($\$10^6$)		
211	111.0	5,511.0	42,268.0	21,784.0
213111	53.0	1,901.0	3,796.0	2,205.0
213112	106.0	3,622.0	3,093.0	1,161.0

Natural gas is used by residential, commercial, industrial, and electric utility users. Total consumption of natural gas in the United States was 22,545 billion cubic feet in 2002. Industrial consumers accounted for the largest share of this total, consuming 7,257 billion cubic feet, while residential, commercial, and electric utility consumption was 4,918 billion cubic feet, 3,117 billion cubic feet, and 5,553 billion cubic feet, respectively. The remainder of U.S. consumption was by natural gas producers in their plants and on their gas pipelines. The largest single application for natural gas is as a domestic or industrial fuel. Natural gas is also becoming increasingly important for generating electricity. Although these are the primary uses, other specialized applications have emerged over the years, such as a nonpolluting fuel for buses and other motor vehicles (DOE, 2003c).

The primary substitutes for oil and natural gas are coal, electricity, and each other. Consumers of these energy products are expected to respond to changes in the relative prices between these four energy sources by changing the proportions of these fuels they consume. For example, if the price of natural gas were to increase relative to other fuels, then it is likely that consumers would substitute oil, coal, and electricity for natural gas. This effect of changing prices is commonly referred to as fuel switching.

The extent to which consumers change their fuel usage depends on such factors as the availability of alternative fuels and the capital requirements involved. If they own equipment that can run on multiple fuels, then it may be relatively easy to switch fuel usage as prices change. However, if existing capital cannot easily be modified to run on an alternative fuel, then it is less likely for a consumer to change fuels in the short run.

If the relative price of the fuel currently in use remains elevated in the long run, some additional consumers will switch fuels as they replace existing capital with new capital capable of using relatively cheaper fuels. For example, if the price of natural gas were to significantly increase relative to the price of electricity for residential consumers, most consumers would be unlikely to replace their natural gas furnaces immediately. However, if the natural gases price consistently remained higher compared to electricity prices over time, residential consumers would be more likely to replace their natural gas furnaces with electric heat pumps as their existing furnaces wear out.

6.4.3 Organization of the Industry: Market Concentration, Plants, and Firms

Many oil and gas firms are merging to remain competitive in both the global and domestic marketplaces. By merging with their peers, these companies may reduce operating expenses and reap greater economies of scale than they would otherwise. Recent mergers, such as BP Amoco and ExxonMobil, have reduced the number of companies and facilities operating in the United States and makes the markets more concentrated.

Most U.S. oil and gas firms are concentrated in states with significant oil and gas reserves, such as Texas, Louisiana, California, Oklahoma, and Alaska. In 1997, there were over 15,000 establishments engaged in operations in NAICS 211 and 213.

The United States is home to half of the major oil and gas companies operating around the globe. Although small firms account for approximately 47 percent of U.S. crude oil and natural gas output, the domestic oil and gas industry is dominated by 24 integrated petroleum and natural gas refiners and producers, such as ExxonMobil and BP Amoco (Spancake, 1999). The latest Census data show over 7,000 companies performing oil and gas extraction or supporting activities (see Table 6-14).

Table 6-14. Crude Petroleum and Natural Gas Establishment and Company Statistics: 1997

NAICS	Description	Number of Companies	Number of Establishments
211	Oil and Gas Extraction	6,859	8,312
213111 and 213112	Support Activities Mining	2,745	8,694

Source: U.S. Department of Commerce, Bureau of the Census. 1999c. *1997 Economic Census, Mining Industry Series*, *Crude Petroleum and Natural Gas Extraction*. Washington, DC: U.S. Department of Commerce.

6.4.4 Markets and Trends

U.S. annual oil and gas production is a small percentage of total U.S. reserves. In 2001, oil producers extracted approximately 1.2 percent of the nation's crude oil reserves (see Table 6-15). A slightly larger percentage of NGLs was extracted (1.4 percent), and a larger percentage of natural gas was extracted (3.0 percent). The United States produces approximately 38 percent (2,118 million barrels) of its annual crude oil consumption, importing the remainder of its crude oil from Canada, Latin America, Africa, and the Middle East (3,405 million barrels). Approximately 17 percent (3,977 billion cubic feet) of U.S. natural gas supply is imported. Most imported natural gas originates in Canadian fields in the Rocky Mountains and off the Coast of Nova Scotia and New Brunswick.

Table 6-15. Estimated U.S. Oil and Gas Reserves, Annual Production, and Imports, 2001

Category	Reserves	Annual Production	Imports
Crude Oil (10^6 barrels)	174,820	2,118	3,405
Natural Gas (10^9 cubic feet)	1,430,630	19,702	3,977
Natural Gas Liquids (10^6 barrels)	23,570	682	1

Sources: U.S. Department of Energy, Energy Information Administration. 2002c. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration. 2002b. *Petroleum Supply Annual 2001, Volume I*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration. 2003c. *Natural Gas Annual 2001*. Washington, DC: U.S. Department of Energy.

Between 1990 and 1998, crude oil consumption increased 1.4 percent per year, and natural gas consumption increased 2.0 percent per year. The increase in natural gas consumption came mostly at the expense of coal consumption (EPA, 1999b). The Energy Information Administration (EIA) anticipates that natural gas consumption will continue to grow, but only at an average annual growth rate of 0.3 percent (not including consumption by electricity generators) through the year 2020. They also expect crude oil consumption to grow at an annual rate of less than 1 percent over the same period (DOE, 2003a).

6.5 Paper and Allied Products

The paper and allied products industry (NAICS 322) is one of the largest manufacturing industries in the United States. In 2001, the industry shipped nearly $156 billion in paper commodities. The industry produces a wide range of wood pulp, primary paper products, and paperboard products such as printing and writing papers, industrial papers, tissues, container board, and boxboard. The industry also includes manufacturers that "convert" primary paper and paperboard into finished products like envelopes, packaging, and shipping containers (EPA, 2002c).

6.5.1 The Supply Side: Production and Costs

6.5.1.1 Production Process

The manufacturing paper and allied products industry is capital- and resource-intensive, consuming large amounts of pulp wood and water in the manufacturing process. Approximately half of all paper and allied products establishments are integrated facilities, meaning that they produce both pulp and paper on-site. The remaining half produce only paper products; few facilities produce only pulp (EPA, 2002c).

The paper and paperboard manufacturing process can be divided into three general steps: pulp making, pulp processing, and paper/paperboard production. Paper and paperboard are manufactured using what is essentially the same process. The principal difference between the two products is that paperboard is thicker than paper's 0.3 mm.

Producers manufacture pulp mixtures by using chemicals, machines, or both to reduce raw material into small fibers. In the case of wood, the most common pulping material, chemical pulping actions release cellulose fibers by selectively destroying the chemical bonds that bind the fibers together (EPA, 2002c). Impurities are removed from the pulp, which then may be bleached to improve brightness. Only about 20 percent of pulp and paper mills practice bleaching (EPA, 2002c). The pulp may also be further processed to aid in the paper-making process.

During the paper-making stage, the pulp is strengthened and then converted into paper. Pulp can be combined with dyes, resins, filler materials, or other additives to better fulfill specifications for the final product. Next, the water is removed from the pulp, leaving the pulp on a wire or wire mesh conveyor. The fibers bond together as they are carried through heated presses and rollers. The paper is stored on large rolls before being shipped for conversion into another product, such as envelopes and boxes, or cut into paper sheets for immediate consumption.

6.5.1.2 Types of Output

The paper and allied products industry's output ranges from writing papers to containers and packaging. Paper products include printing and writing papers; paperboard boxes; corrugated and solid fiber boxes; fiber cans, drums, and similar products; sanitary food containers; building paper; packaging; bags; sanitary paper napkins; envelopes; stationary products; and other converted paper products.

6.5.1.3 Major By-Products and Co-Products

The paper and allied products industry is the largest user of industrial process water in the United States. In 2000, a typical mill used between 4,000 and 12,000 gallons of water per ton of pulp produced. The equivalent amount of waste water discharged per ton of pulp ranges from 14 to 140 kg (EPA, 2002c). Most facilities operate waste water treatment facilities on site to remove biological oxygen demand (BOD), total suspended solids (TSS), and other pollutants before discharging the water into a nearby waterway.

6.5.1.4 Production Costs

Historical statistics for the costs of production for the paper and allied products industry are listed in Table 6-16. From 1997 to 2001, industry payroll generally ranged from approximately $22 to 23 billion. Employment peaked at 574,300 people in 1997 and declined slightly to 530,200 people by 2001. Materials costs averaged $83.1 billion a year and new capital investment averaged $7.7 billion a year.

6.5.2 The Demand Side

Paper is valued for its diversity in product types, applications, and low cost due to ready access to raw materials. Manufacturers produce papers of varying durabilities, textures, and colors. Consumers purchasing large quantities of papers may have papers tailored to their specification. Papers may be simple writing papers or newsprint for personal consumption and for the printing and publishing industry or durable for conversion into shipping cartons, drums, or sanitary boxes. Inputs in the paper production process are readily available in the United States because one-third of the country is forested, and facilities generally have ready access to waterways.

Table 6-16. Inputs for the Paper and Allied Products Industry (NAICS 322), 1997–2001

Year	Labor: Quantity (10^3)	Labor: Payroll (\$$10^6$)	Materials (\$$10^6$)	Total Capital Expenditures (\$$10^6$)
1997	574.3	22,312.0	80,189.5	8,595.1
1998	572.4	22,529.5	82,419.4	8,546.7
1999	560.7	22,837.4	82,720.9	7,081.1
2000	548.3	22,680.1	87,346.6	7,383.5
2001	530.2	22,188.3	82,823.0	6,797.4

Sources: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures 2001*. Washington, DC: Government Printing Office.

The paper and allied products industry is an integral part of the U.S. economy; nearly every industry and service sector relies on paper products for its personal, education, and business needs. Among a myriad of uses, papers are used for correspondence, printing and publishing, packing and storage, and sanitary purposes. Common applications are all manners of reading material, correspondence, sanitary containers, shipping cartons and drums, and miscellaneous packing materials.

6.5.3 Organization of the Industry: Market Concentration, Plants, and Firms

For the paper and allied products industry, the CR4 equaled 18.5 in 1997 (see Table 6-17). This means that the top four firms' combined sales were 18.5 percent of the industry's total sales. This industry's unconcentrated nature is also indicated by its HHI of 173.3.

Table 6-17. Measures of Market Concentration for Paper and Allied Products Markets, 1997

NAICS	Description	CR4	CR8	HHI	Number of Companies	Number of Facilities
322	Paper Manufacturing	18.5	31.1	173.3	3,808	5,868

Source: U.S. Department of Commerce, Bureau of the Census. 2001. *1997 Economic Census, Manufacturing Subject Series, Concentration Ratios in Manufacturing*. Washington, DC: Government Printing Office.

In 1997, 3,808 companies produced paper and allied products and operated 5,868 facilities. By way of comparison, 4,264 companies controlled 6,416 facilities in 1992. Even though they account for only 46 percent of all facilities, those with 50 or more employees contribute more than 92 percent of the industry's total value of shipments (see Table 6-18).

Table 6-18. Size of Establishments and Value of Shipments for the Paper and Allied Products Industry (NAICS 322)

Number of Employees in Establishment	1987		1992		1997	
	Number of Facilities	Value of Shipments ($\$10^6$)	Number of Facilities	Value of Shipments ($\$10^6$)	Number of Facilities	Value of Shipments ($\$10^6$)
1 to 4 employees	729	640.6	786	216	687	D
4 to 9 employees	531	D	565	483	500	605.2
10 to 19 employees	888	1,563.4	816	1,456.5	706	1,672.7
20 to 49 employees	1,433	18,328.6	1,389	6,366.6	1,292	7,345.4
50 to 99 employees	1,018	D	1,088	12,811.5	1,033	14,686.8
100 to 249 employees	1,176	32,141.7	1,253	35,114.0	1,193	40,366.0
250 to 499 employees	308	24,221.1	298	22,281.2	265	23,940.2
500 to 999 employees	145	28,129.1	159	31,356.5	131	32,060.7
1,000 to 2,499 employees	63	24,903.1	62	23,115.4	59	26,780.6
2,500 or more employees	1	D			2	D
Total	1,732	129,927.8	6,416	133,200.7	5,868	150,295.9

D = undisclosed

Sources: U.S. Department of Commerce, Bureau of the Census. 1991. *1987 Census of Manufactures, Subject Series, General Summary*. Washington, DC: Government Printing Office.

U.S. Department of Commerce, Bureau of the Census. 1996. *1992 Census of Manufactures, Subject Series: General Summary*. Washington, DC: Government Printing Office.

U.S. Department of Commerce, Bureau of the Census. 2002a. *1997 Economic Census, Manufacturing Subject Series, General Summary*. Washington, DC: Government Printing Office.

Capacity utilization measures are used to track a variety of economic conditions, specific to the path of the business cycle and employment and inflationary trends. Table 6-19 presents the trend in capacity utilization for the paper and allied products industry. The varying capacities reflect changes in the industry and the economy as a whole. The average capacity utilization ratio for the paper and allied products industry between 1997 and 2001 was approximately 81, with capacity declining in recent years.

Table 6-19. Capacity Utilization Ratios for the Paper and Allied Products Industry, 1997–2001

1997	1998	1999	2000	2001
85	83	83	79	76

Note: All values are percentages.
Source: U.S. Department of Commerce, Bureau of the Census. 2003b. *Current Industry Reports, Survey of Plant Capacity: 2001.* Washington, DC: Government Printing Office.

6.5.4 Markets and Trends

The industry's performance is tied to raw material prices, labor conditions, and worldwide inventories and demand (EPA, 2002c). Industry performance was strong until 2001, when the value of shipments decreased by 6 percent (see Table 6-20). Over the entire 5-year period from 1997 to 2001, the value of shipments increased by 3.7 percent.

Table 6-20. Value of Shipments for the Paper and Allied Products Industry (NAICS 322), 1997–2001

Year	Value of Shipments ($\$10^6$)
1997	150,295.9
1998	154,984.2
1999	156,914.9
2000	165,297.4
2001	155,846.0

Source: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures, 2001*. Washington, DC: Government Printing Office.

The Department of Commerce projects that shipments of paper and allied products will increase through 2004 by an annual average of 2.1 percent (Stanley, 1999). Because nearly all of the industry's products are consumer related, shipments will be most affected by the health of the U.S. and global economy. The United States is a key competitor in the international market for paper products and, after Canada, is the largest exporter of paper products. U.S. exports and imports are both expected to increase 3 percent annually through 2004.

6.6 Petroleum Refining Industry

The petroleum refining industry is an important industry in the U.S. economy accounting for approximately 4 percent of the manufacturing sector's value of shipments. In this section, we describe the current refinery process, raw materials used, uses and consumers, industry organization, and markets and trends with particular emphasis on distillate fuel uses.

6.6.1 The Supply Side: Production and Costs

6.6.1.1 Refinery Production Processes/Technology

Petroleum refining is the physical, thermal, and chemical separation of crude oil into its major distillation fractions, followed by further processing (through a series of separation and conversion steps) into highly valued finished petroleum products. Although refineries are extraordinarily complex and each site has a unique configuration, we describe a generic set of unit operations that are found in most medium and large facilities. A detailed discussion of these processes can be found in EPA's sector notebook of the petroleum refining industry (EPA, 1995c); simplified descriptions are available on the Web sites of several major petroleum producers (Flint Hills Resources, 2002; Chevron, 1998).

After going through an initial desalting process to remove corrosive salts, crude oil is fed to an atmospheric distillation column that separates the feed into several fractions. The lightest of the fractions are processed through reforming and isomerization units into gasoline or diverted to lower-value uses such as liquefied petroleum (LP) gas and petrochemical feedstocks. The middle-boiling fractions make up the bulk of the aviation fuel, diesel, and heating oil produced from the crude. In most refineries, the undistilled liquid (called bottoms) is sent to a vacuum still to further fractionate this heavier material. Bottoms from the vacuum distillation can be further processed into low-value products such as residual fuel oil, asphalt, and petroleum coke.

The middle fractions, however, are not suitable for sale immediately after distillation. They are treated via one of several types of downstream processing: cracking, which breaks large hydrocarbon molecules into smaller ones; combining (alkylation, for example), which combines small molecules into larger, more useful entities; and reforming, in which petroleum molecules are reshaped into higher quality molecules. It is in the reforming operation that the octane rating of gasoline is increased to the level desired for final sale. A downstream purification process, called hydrotreating, helps remove chemically bound sulfur from petroleum products and is critically important for refineries to achieve the low sulfur levels that the proposed regulations will mandate.

For each of the major products, several product streams from the refinery will be blended into a finished mixture. For example, diesel fuel will typically contain a straight-run fraction from crude distillation, distillate from the hydrocracker, light-cycle oil from the catalytic cracker, and hydrotreated gas oil from the coker. Several auxiliary unit operations are also needed in the refinery complex, including hydrogen generation, catalyst handing and regeneration, sulfur recovery, wastewater treatment, and blending and storage tanks.

Refining, like most continuous chemical processes, has high fixed costs from the complex and expensive capital equipment installed. In addition, shutdowns are very expensive, because they create large amounts of off-specification product that must be recycled and reprocessed prior to sale. As a result, refineries attempt to operate 24 hours per day, 7 days per week, with only 2 to 3 weeks of downtime per year. Intense focus on cost-cutting has led to large increases in capacity utilization over the past several years. A Federal Trade Commission investigation into the gasoline price spikes in the Midwest during the summer of 2000 disclosed an average utilization rate of 94 percent during that year, and EIA data from 2001 show that a 92.6 percent utilization rate was maintained in 2001 (FTC, 2002; EIA, 2002b).

6.6.1.2 Potential Changes in Refining Technology Due to EPA Regulation

Over the next few years, EPA regulations will come into effect that require much lower levels of residual sulfur for both gasoline and highway diesel fuel. To meet these challenges, refineries are planning to add hydrotreater units to their facilities, route more intermediate product fractions through existing hydrotreaters, and operate these units under more severe conditions to reduce levels of chemically bound sulfur in finished products. As has been documented in economic impact analyses for the gasoline and highway diesel rules, these changes will require capital for equipment, new piping, and in-process storage, increased use of catalyst and hydrogen, and different operating strategies.

The addition of lower sulfur limits for nonroad diesel fuel will result in additional costs similar in nature to those required for the highway diesel fuel. Product streams formerly sent directly to blending tanks will need to be routed through the hydrotreating operation to reduce their sulfur level. In addition, because an increasing fraction of the total volumetric output of the facility must meet ultralow sulfur requirements, flexibility will be somewhat reduced. For example, it will become more difficult to sell off spec products if errors or equipment failures occur during operation.

6.6.1.3 Types of Products

The major products made at petroleum refineries are unbranded commodities, which must meet established specifications for fuel value, density, vapor pressure, sulfur content, and several other important characteristics. These products are transported through a distribution network to wholesalers and retailers, who may attempt to differentiate their fuel from competitors based on the inclusion of special additives or purely through adroit marketing. Gasoline and highway diesel are taxed prior to final sale, whereas nonroad fuel is not. To prevent accidental or deliberate misuse, nonroad diesel fuel must be dyed prior to final sale.

A total of $158.7 billion of petroleum products were sold in the 1997 census year, accounting for approximately 0.4 percent of GDP. Motor gasoline is the dominant product, both in terms of volume and value, with almost 3 billion barrels produced in 1997 (see Table 6-21). Distillate fuels accounted for less than half as much as gasoline, with 1.3 billion barrels produced in the United States in the same year. Data from the EIA suggest that 60 percent of that total is low-sulfur highway diesel, with the remainder split between nonroad diesel and heating oil. Jet fuel, a fraction slightly heavier than gasoline, is the third most important product, with a production volume of almost 600 million barrels.

6.6.1.4 Production Costs

The costs of production are divided into the main input categories of labor, materials, and capital expenditures (see Table 6-22). Of these categories, the cost of materials represents about 80 percent of the total value of shipments, varying from year to

Table 6-21. Types of Petroleum Products Produced by U.S. Refineries

Products	Total Produced (thousand barrels)	Percentage of Total
Liquified refinery gases	243,322	3.9%
Finished motor gasoline	2,928,050	46.4%
Finished aviation	6,522	0.1%
Jet fuel	558,319	8.8%
Kerosene	26,679	0.4%
Distillate fuel oil	1,348,525	21.4%
Residual fuel oil	263,017	4.2%
Naphtha for feedstock	60,729	1.0%
Other oils for feedstock	61,677	1.0%
Special naphthas	18,334	0.3%
Lubricants	63,961	1.0%
Waxes	6,523	0.1%
Petroleum coke	280,077	4.4%
Asphalt and road oil	177,189	2.8%
Still gas	244,432	3.9%
Miscellaneous	21,644	0.3%
Total	**6,309,000**	**100.0%**

Source: U.S. Department of Energy, Energy Information Administration. 2002b. *Petroleum Supply Annual 2001 Volume 1*. Washington, DC: U.S. Department of Energy.

Table 6-22. Petroleum Refinery Costs of Production

Petroleum Refinery Costs of Production	Cost ($\$10^6$)	Cost as Percent of Product Value (%)
Cost of materials	$158,733	79.4%
Cost of labor	4,233	2.1%
Capital expenditures	6,817	3.4%

Source: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures, 2001*. Washington, DC: Government Printing Office.

year as crude petroleum prices change. Labor and capital expenditures tend to be more stable, accounting for about 2 to 3 percent of the value of shipments in 2001.

6.6.2 The Demand Side

This section describes the demand side of the market for refined petroleum products, with a focus on the distillate fuel oil industry. It discusses the primary consumer markets identified and their distribution by end use and petroleum administration defense district (PADD) (see Figure 6-3). This section will also consider substitution possibilities available in each of these markets and the feasibility and costs of these substitutions.

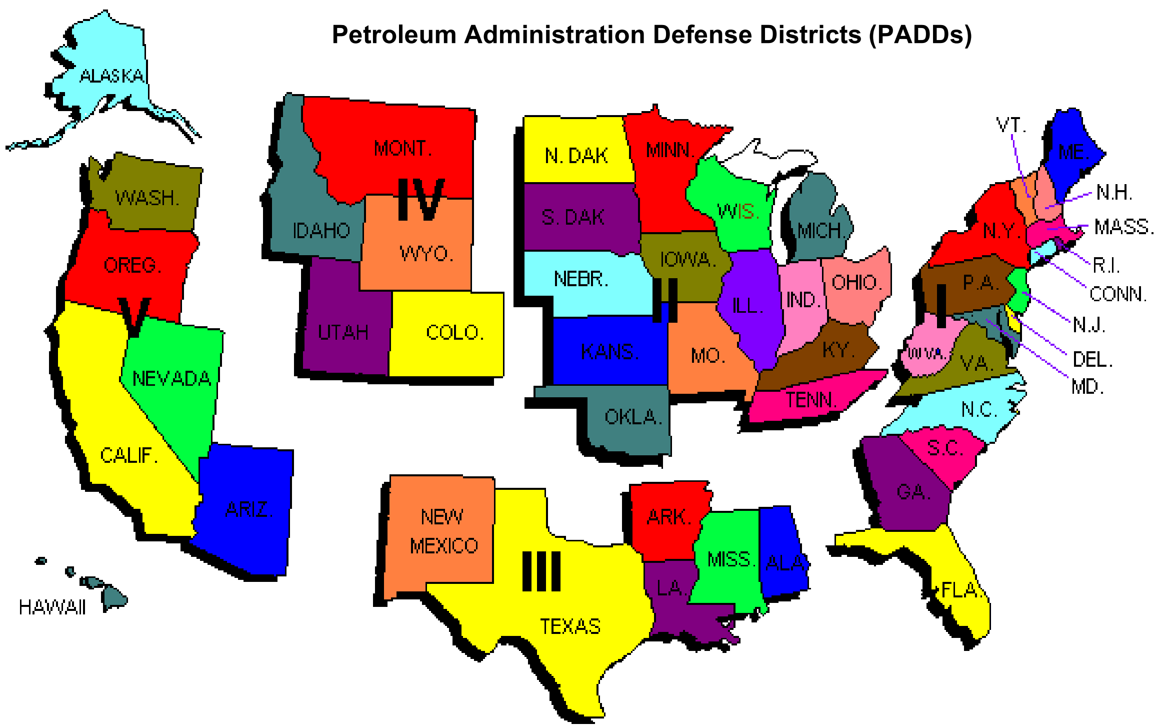

Figure 6-3. PADD Districts of the United States

6.6.2.1 Uses and Consumers

As Table 6-23 shows, highway diesel usage of 33.1 billion gallons represents the bulk of distillate fuel usage (58 percent) in 2000. Residential distillate fuel usage, which in the majority is fuel oil, accounts for 11 percent of total usage in 2000. Nonroad diesel fuel is primarily centered on industrial, farm, and off-highway diesel (construction) usage. In 2000, these markets consumed about 13 percent of total U.S. distillate fuels.

Table 6-23. Adjusted Sales of Distillate Fuel Oil by End Use (2000)

End Use	2000 Usage (thousand gallons)	Percent Share (%)
Residential	6,204,449	10.8%
Commercial	3,372,596	5.9%
Industrial	2,149,386	3.8%
Oil company	684,620	1.2%
Farm	3,168,409	5.5%
Electric utility	793,162	1.4%
Railroad	3,070,766	5.4%
Vessel bunking	2,080,599	3.6%
On-highway diesel	33,129,664	57.9%
Military	233,210	0.4%
Off-highway diesel	2,330,370	4.1%
Total	**57,217,231**	**100.0%**

Source: U.S. Department of Energy, Energy Information Administration. 2001. *Fuel Oil and Kerosene Sales 2000*. Washington, DC: U.S. Department of Energy.

To determine the regional distribution of distillate fuel usage, 2000 sales of distillate fuel are categorized by PADDs. As shown by Table 6-24, PADD I (the East Coast) consumes the greatest amount of distillate fuel oil at 20.9 billion gallons. However, residential, locomotive, and vessel bunking consumers account for 6.4 billion gallons of the distillate consumed, which means that at least one-third of the distillate consumed in PADD I is due to fuel oil and not to diesel fuel consumption.

Table 6-24. Adjusted Sales of Distillate Fuel Oil by End Use and by PADD

Enduse	PADD (Thousand Gallons)				
	I	II	III	IV	V
Residential	5,399,194	628,414	1,117	38,761	136,962
Commercial	2,141,784	568,089	346,578	102,905	213,240
Industrial	649,726	600,800	420,400	241,146	237,313
Oil company	19,101	41,727	560,905	29,245	33,643
Farm	432,535	1,611,956	552,104	220,437	351,377
Electric utility	304,717	133,971	194,786	8,492	151,196
Railroad	499,787	1,232,993	686,342	344,586	307,059
Vessel bunking	490,150	301,356	1,033,333	173	255,586
On-highway diesel	10,228,244	11,140,616	5,643,703	1,474,611	4,642,490
Military	70,801	36,100	9,250	4,163	112,895
Off-highway diesel	669,923	608,307	516,989	180,094	355,056
Total	**20,905,962**	**16,904,329**	**9,965,507**	**2,644,613**	**6,796,817**

Source: U.S. Department of Energy, Energy Information Administration. 2001. *Fuel Oil and Kerosene Sales 2000*. Washington, DC: U.S. Department of Energy.

6.6.2.2 Substitution Possibilities in Consumption

For engines and other combustion devices designed to operate on gasoline, there are no practical substitutes, except among different grades of the same fuel. Because EPA regulations apply equally to all gasoline octane grades, price increases will not lead to substitution or misfueling. In the case of distillate fuels, it is currently possible to substitute between low-sulfur diesel (LSD), high-sulfur diesel (HSD), and #2 fuel oil, although higher sulfur levels are associated with increased maintenance and poorer performance.

With the consideration of more stringent nonroad fuel and emission regulations, substitution will become less likely. Switching from nonroad ultralow-sulfur diesel (ULSD) to highway ULSD is not financially attractive, because of the taxes levied on the highway product. Misfueling with high-sulfur fuel oil will rapidly degrade the performance of the exhaust system of the affected engine, with negative consequences for maintenance and repair costs.

6.6.3 Industry Organization: Market Concentration, Plants, and Firms

To determine the ultimate effects of the EPA regulation, it is important to have a good understanding of the overall refinery industry structure. The degree of industry concentration, regional patterns of production and shipment, and the nature of the corporations involved are all important aspects of this discussion. In this section, we look at market measures for the United States as a whole and by PADD region.

6.6.3.1 Market Structure—Concentration

There is a great deal of concern among members of the public about the nature and effectiveness of competition in the refining industry. Large price spikes following supply disruptions and the tendency for prices to slowly fall back to more reasonable levels has created suspicion of coordinated action or other market imperfections in certain regions. The importance of distance in total delivered cost to various end-use markets also means that refiners incur a wide range of costs in serving some markets; since the price is set by the highest cost producer serving the market, profits are made by the low-cost producers in those markets.

There is no convincing evidence in the literature that markets should be modeled as imperfectly competitive, however. Although the FTC study cited above concluded that the extremely low supply and demand elasticities made large price movements likely and inevitable given inadequate supply or unexpected increases in demand, their economic analysis found no evidence of collusion or other anticompetitive behavior in the summer of 2000. Furthermore, the industry is not highly concentrated on a nationwide level or within regions. The 1997 Economic Census presented the following concentration information: four-firm CR of 28.5 percent, eight-firm CR of 48.6 percent, and an HHI of 422 (U.S. Department of Commerce, 2001). Merger guidelines followed by the Department of Justice consider that there is little potential for pricing power in an industry with an HHI below 1,000 (DOJ, 1997).

6.6.3.2 Plants and Firms

As of January 2003, there were 145 operating petroleum refineries in the United States (Table 6-25). An additional four refineries were operable but idle. Nearly 40 percent of the nation's refineries were contained in PADD III. This region also accounts for 45 to 50 percent of U.S. refinery net production of finished motor gasoline, distillate fuel oil, and

Table 6-25. Number of Petroleum Refineries by PADD, 2003

PADD	Number of Facilities	Percent of Total
I	13	9.0
II	26	17.9
III	54	37.2
IV	16	11.0
V	36	24.8
Total	**145**	**100.0%**

Source: U.S. Department of Energy, Energy Information Administration. 2003d. *Petroleum Supply Annual 2002, Volume 1*. Washington, DC: U.S. Department of Energy.

residual fuel oil, which is not surprising since PADD III contains the petroleum-rich states of Texas and Louisiana. PADD I had the fewest refineries of the five districts.

According to the EIA Petroleum Supply Annual 2001, the top three owners of crude distillation facilities are ExxonMobil Corp (11 percent of U.S. total), Phillips Petroleum Corp (10 percent), and BP PLC (9 percent). Information is not available on actual production of highway diesel, nonroad diesel, and other distillate fuels for each refinery. It should be noted that PADD III has more than 50 percent of the total crude distillation capacity and the three largest single facilities (U.S. Department of Energy, 2002b).

6.6.3.3 Firm Characteristics

Many of the large integrated refineries are owned by major petroleum producers, which are among the largest corporations in the United States. According to *Fortune Magazine's* Fortune 500 list, ExxonMobil is the second largest corporation in the world, as well as in the United States. Chevron Texaco ranks as the eighth largest U.S. corporation, placing it 14th in the world. The newly merged Phillips and Conoco entity will rank in the top 20 in the United States, and six more U.S. petroleum firms make the top 500. BP Amoco (fourth worldwide) and Royal Dutch Shell (eighth worldwide) are foreign owned, as is Citgo (owned by Petroleos de Venezuela).

On the other hand, several of the smallest refineries are certified as small businesses by EPA. A total of 21 facilities owned by 17 different parent companies qualify or have applied for small-business status (EPA, 2002a). These small refineries are concentrated in the Rocky Mountain and Great Plains region of PADD IV, and their conversion to ULSD is likely to require significant flexibility on the part of EPA.

6.6.4 Markets and Trends

Markets for nonroad diesel and other distillate products have been growing irregularly over the past several years. Table 6-26 shows that residential and commercial use of fuel oil has been dropping steadily since 1984, while highway diesel use has nearly doubled over the same period. Farm use of distillate has been flat over the 15-year period, while off-highway use, mainly for construction, has increased by 40 percent.

6.7 Primary Metal Manufacturing

The primary metal manufacturing industries (NAICS 331) includes industries involved in the primary and secondary smelting and refining of ferrous and nonferrous metal from ore or scrap. Primary smelting and refining produces metals directly from ores, while secondary processes produce metals from scrap and process waste. Nonferrous metals produced by NAICS 331 industries include aluminum, lead, copper, and zinc. The iron and steel sector comprises establishments involved in direct reduction of iron ore, manufacturing pig iron and converting it into steel, and manufacturing steel and converting it to shapes or tubes and pipes (EPA, 2003).

6.7.1 The Supply Side: Production and Costs

6.7.1.1 Production Processes

Iron and Steel. In the United States, the highest geographic concentration of steel mills exists in the Great Lakes region, which is home to most integrated plants. Historically, mill sites were selected for their proximity to water sources, so very few mills operate in the western United States. Because of the high cost of new capital and the long lead time needed to introduce new equipment into the industry, changes in production methods and products are generally made gradually, which makes it difficult for the industry to adjust to market fluctuations.

There are two types of steelmaking technology in use today. The first is the basic oxygen furnace (BOF), which uses molten iron, scrap, and oxygen as input materials and requires cokemaking and ironmaking as intermediate steps in steel production. The second technique is the electric arc furnace (EAF), which uses electricity and scrap as inputs and does not require the intermediate steps of the (BOF) method.

Table 6-26. Sales of Distillate Fuel Oils to End Users 1984–1999 (thousands of barrels per day)

Year	Resi-dential	Com-mercial	Indust-rial	Oil Comp-any	Farm	Electric Utility	Rail-road	Vessel Bunkering	On-Highway Diesel	Military	Off-Highway Diesel	All Other	Total
1984	450	319	153	59	193	45	225	110	1,09345	45	109	44	2,845
1985	471	294	169	57	216	34	209	124	1,12750	50	105	12	2,868
1986	476	280	175	49	220	40	202	133	1,16950	50	111	9	2,914
1987	484	279	190	58	211	42	205	145	1,18558	58	113	5	2,976
1988	498	269	170	57	223	52	212	150	1,30464	64	119	4	3,122
1989	489	252	167	55	209	70	213	154	1,37861	61	107	2	3,157
1990	393	228	160	63	215	48	209	143	1,39351	51	116	(s)	3,021
1991	391	226	152	59	214	39	197	141	1,33654	54	110	(s)	2,921
1992	406	218	144	51	228	30	209	146	1,39142	42	113	(s)	2,979
1993	429	218	128	50	211	38	190	133	1,48531	31	127	(s)	3,041
1994	413	218	136	46	209	49	200	132	1,59434	34	130	(s)	3,162
1995	416	216	132	36	211	39	208	129	1,66824	24	126	—	3,207
1996	436	223	137	41	217	45	213	142	1,75424	24	134	—	3,365
1997	423	210	141	41	216	42	200	137	1,86722	22	136	—	3,435
1998	367	199	147	37	198	63	185	139	1,96718	18	142	—	3,461
1999	381	196	142	38	189	60	182	135	2,09119	19	140	—	3,572

Source: U.S. Department of Energy, Energy Information Administration. 2002a. *Annual Energy Review 2001*. Washington, DC: U.S. Department of Energy.

For the BOF technique, the process begins with the manufacturing of coke. This starts with bituminous pulverized coal charge, which is fed into a coke oven and heated in the absence of oxygen. Volatile compounds are driven from the coal, and the resulting product is coke. After heating, the coke is cooled with water and screened. This process generates the most environmental concern, with air emissions and quench water use cited as major problems. Industry experts predict that U.S. imports of coke will rise in the future, because of the high cost of constructing new environmentally friendly production facilities.

The next production stage produces molten iron from iron ore, coke, and limestone, which are heated in a furnace. This heat burns the coke, which creates carbon monoxide to reduce iron ore to iron. Finally, the molten iron from the furnace is combined with flux, alloy materials, and scrap in the basic oxygen furnace, melted, and exposed to high-purity oxygen. The end product of this process is molten steel.

Production facilities using the EAF use scrap metal as the primary raw material. This metal is melted and refined using electric energy. The melting process prompts the oxidation of phosphorus, silicon, manganese, carbon and other materials, which form a slag on top of the molten metal.

Regardless of the production process, the output is molten steel, which is formed into ingots or slabs that are rolled into finished products. The rolling process may consist of reheating, rolling, cleaning, and coating of the steel. The forming process generally used in facilities today is called the continuous casting process, in which the molten steel is cast directly into semifinished shapes (EPA, 1995a).

Nonferrous metals. The process for manufacturing nonferrous metals involves primary and secondary smelting and refining of ore or scrap; rolling, drawing, and alloying; and the manufacturing and casting of basic metal products. Two recovery technologies are used to produce refined metals. The first is pyrometallurgical technologies, which use heat to separate desired metals from other materials. Examples of this process include drying, calcining, roasting, sintering, retorting, and smelting. In contrast, hydrometallurgical technologies separate desired from undesired metals by taking advantage of differences between constituent solubilities and/or electrochemical properties while in aqueous solutions.

During pyrometallic processing, an ore is combined by heat with materials such as baghouse dust and flux. This combination is melted to fuse the desired materials into a molten bullion. This bullion is again refined to increase the purity. This process varies according to the raw ore, but the basic steps remain the same for pyrometallic processing (EPA, 1995b).

Aluminum, copper, lead, and zinc are the more most widely used nonferrous metals in the United States. The production of each of these metals is briefly discussed below.

Aluminum. In the early 1990s, most of the primary aluminum producers in the United States were located in either the Northwest or the Ohio River Valley to take advantage of hydroelectric power and coal-based energy. Most of the secondary smelters were located in Southern California and the Great Lakes region near major industrial centers for access to large amounts of scrap metal.

Primary aluminum producers use a three-step process to produce aluminum alloy ingots. In the first step alumina is extracted from bauxite oar using the Bayer process. In this process, finely crushed bauxite is mixed with an aqueous sodium hydroxide solution to form a slurry, which is heated and put through a series of chemical reactions to separate aluminum hydroxide crystals from the rest of the materials. In the second step, the dewatered aluminum oxide (alumina) is reduced to make pure molten aluminum. The alumina is heated and electrically charged to separate the oxygen from the aluminum, which is then siphoned off and transferred to melting and holding furnaces. The third step consists of either adding other metals to create alloys of specific characteristics or casting aluminum into ingots for transport to fabricating shops.

Secondary production of aluminum involves the melting of scrap in oil- or gas-fired reverberatory furnaces. The molten metal is then treated with chlorine or various fluxes to remove magnesium (EPA, 1995b).

Copper. Copper ore is mined in the northern and southern hemisphere but is primarily processed and consumed by countries in the northern hemisphere. The United States is a major producer and consumer of copper products. Copper ore, mined from open pits and underground mines, contains less than 1 percent copper. This ore is crushed and concentrated by mixing it with water, chemical reagents, and air. The air attaches to the copper minerals and rises to the top, where the new concentrate (approximately 20 to 30 percent copper) is skimmed off.

Like steel, copper can be produced either pyrometallurgically or hydrometallurgically. Ore concentrates, which contain high levels of copper sulfide and iron sulfide minerals are treated by the pyrometallurgical process, while oxide ores that contain copper oxide minerals and other oxidized waste minerals are treated by hydrometallurgical processes (EPA, 1995b).

Lead. The United States is one of the world's largest recycler of lead scrap and can meet almost all domestic needs for refined lead production from scrap recycling. The primary lead production process consists of four steps: sintering, smelting, drossing, and pyrometallurgical refining. After a feedstock of lead concentrate completes these four steps, the resulting refined lead will have a purity greater than 99.9 percent and can be mixed with other minerals to form alloys.

The secondary production process uses old scrap and new scrap from primary production to manufacture lead. The main source of lead scrap in the United States is lead-acid batteries. Once the lead battery scrap is broken and classified by lead type, it is processed in blast furnaces or rotary reverberatory furnaces (EPA, 1995b).

Zinc. The primary production of zinc starts with zinc concentrate and reduces it to metal either pyrometallurgically by distillation or hydrometallurgically by electrowinning. Nearly 80 percent of zinc refining is done hydrometallurgically. This process takes the zinc concentrate through four steps: calcinating, leaching, purification, and electrowinning. Calcining involves mixing zinc-containing materials with coal then heating the mixture to vaporize the zinc oxide, which is the desired output for this step. Next, the zinc oxide is dissolved in a sulfuric acid solution. The third production step involves adding zinc dust, which causes the undesirable elements to precipitate for easy filtering. The final step runs an electric current through the aqueous zinc solution to cause the zinc to attach to aluminum plates. These aluminum plates are then stripped and the zinc concentrate is melted and cast into ingots (EPA, 1995b).

For secondary zinc production, zinc-containing metals are melted in a sweating furnace and the molten zinc is recovered and refined. Recovered zinc is generally comparable to primary zinc in quality, and secondary zinc production will most likely increase in the future due to environmental concerns (EPA, 1995b).

6.7.1.2 Types of Output

The iron and steel industry produces iron and steel bars, strips, and sheets, as well as finished products such as steel nails, spikes, wire, rods, pipes, and ferroalloys. By-products derived from the coke manufacturing process such as coal tar and distillates are also categorized as iron and steel industry products (EPA, 1995a). Both the primary and secondary aluminum production processes result in ingots of pure aluminum that serve as feedstock for other materials and processes. Primary forms of aluminum include bars, foils, pipes, plates, rods, sheets, tubes, and wire. Other nonferrous metal production results in similar output. Facilities may also produce nonferrous nails, brads, and spikes as well as metal power, flakes, and paste (U.S. Department of Commerce, 2002b).

6.7.1.3 Major By-Products and Co-Products

For steel production, the by-products produced depend on whether the BOF or EAF was used. When production uses a BOF, the process of cokemaking produces coal tar, light oil, ammonia liquor, and fuel. Coal tar is typically refined and used to produce various commercial and industrial products. Additionally, the cokemaking process emits fine coke particles during coke transport. Approximately 1 pound of particles per ton of coke produced is captured by pollution control equipment.

Ironmaking produces residual sulfur dioxide and particulates, which are most often captured in gas during the production process. Regardless of the furnace used, the steelmaking process emits metal dusts made of iron particulate, zinc, and other metals (EPA, 1995a).

Large amounts of sulfur are released during all of the nonferrous metal smelting operations covered in the previous section. Primary and secondary aluminum manufacturing release particulates, although the particulate matter generated during the calcining of hydrated aluminum oxide is valuable enough to the production process that facilities use extensive controls to reduce these emissions.

Copper production creates sulfur dioxide as a by-product, and this gas is generally collected and made into sulfuric acid, which can be sold or used in other operations. The copper refining process removes solid matter from molten copper. This matter forms a sludge, which is collected and scanned for precious metals, such as gold and silver. Particulate matter, primarily made of copper and iron oxides, is the principal air contaminant emitted during copper smelting, conversion, and secondary copper processing.

The particulate matter emitted from blast furnaces during lead production includes lead oxides, quartz, limestone, iron pyrites, arsenic, and other metallic compounds. Additionally, about 7 percent of the total sulfur in the raw ore is emitted as sulfur dioxide. Fabric filters and electrostatic precipitators are most commonly used to control emissions.

Like copper production, zinc production results in the creation of sulfur dioxide, which is collected and made into sulfuric acid. More than 90 percent of potential sulfur dioxide emissions are generated during the roasting process. This stage in the production process also releases particulate matter containing zinc and lead (EPA, 1995b).

6.7.1.4 Production Costs

Similar to the trend in the value of shipments for the industry, all inputs shown in Table 6-27 fell over the 5-year period. Low market prices and high production costs caused many companies to close plants or cut employment in an attempt to compete with world prices. Employment fell 12 percent and the industry payroll (in unadjusted dollars) fell 7 percent. For all inputs other than labor, there was a slight increase between 1999 and 2000, but this upward swing was not maintained and the 2001 levels for all inputs were lower than the 1997 levels. Total capital investment experienced the largest decrease in percentage terms, with the 2001 level more than 20 percent less than the 1997 level. The cost of materials fell by roughly 17 percent.

Table 6-27. Inputs for the Primary Metal Manufacturing Industry (NAICS 331), 1997–2001

	Labor			
Year	**Quantity (10^3)**	**Payroll (\$$10^6$)**	**Materials (\$$10^6$)**	**Total Capital Investment (\$$10^6$)**
1997	605.1	23,811.2	99,343.3	6,515.8
1998	602.3	24,146.1	96,949.7	6,451.2
1999	582.8	23,722.4	90,596.0	5,942.8
2000	577.8	24,155.1	93,736.3	6,138.3
2001	532.9	22,199.3	83,301.3	5,140.2

Sources: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures 2001*. Washington, DC: Government Printing Office.

6.7.2 The Demand Side

The steel industry has seen significant changes over the last 30 years. Historically, the two largest steel-consuming industries have been the automotive and construction industry, so fluctuations in these industries affect demand for iron and steel products.

Recently, however, foreign competition and technological advances in other materials have reduced the market share of domestic steel producers (EPA, 1995a). For example, the recent popularity of large sport utility vehicles pushed the auto industry to control the weight of these large vehicles. While this trend may increase the demand for lighter-weight steel, manufacturers are looking for substitutes of different materials (Bell, 1999).

Aluminum demand comes mainly from three industries: containers and packaging, transportation, and building and construction. Combined, these three sectors accounted for two-thirds of all aluminum shipments in 1999 (Cammarota, 1999). The leading domestic consumer of refined copper in 1998 was wire rod mills, which accounted for three-quarters of domestic consumption. The majority of the remaining quarter went to brass mills producing copper and copper alloy semi-fabricated shapes (Shaw, 1999). The construction and electronic products industries are the leading consumers of copper and copper alloy, and transportation equipment such as radiators also accounts for a large share of end-use copper. Copper chemicals, primarily copper sulfate and the cupric and cuprous oxides, are widely demanded for use in algaecides, fungicides, wood preservatives, copper plating, and pigments (EPA, 1995b).

The most important end use for lead is the lead acid battery, which accounted for approximately 72 percent of global lead consumption in the late 1990s. Although lead-acid batteries include batteries for household use, the largest consumers are in industrial sectors. Lead oxides are used in television glass and computers, construction, protective coatings, and ballasts (EPA, 1995b).

Zinc is generally consumed in metal (80 percent) or compound form. The largest segment in the zinc market is for galvanizing steel, which is used in the automotive and construction industries for corrosion protection (Larrabee, 1999b). Zinc compound use varies widely but is used mainly by agricultural, chemical, paint, pharmaceutical, and rubber sectors of the economy (EPA, 1995b).

6.7.3 Organization of the Industry: Market Concentration, Plants, and Firms

Table 6-28 displays various measures of market concentration for the entire industry. A CR4 measure of 13.8 indicates that the four firms with the highest sales in the industry account for a total of 13.8 percent of total industry sales. The HHI value of 97.4 shows that the industry is unconcentrated.

Table 6-28. 1997 Measures of Market Concentration for the Primary Metal Manufacturing Industry (NAICS 331)

NAICS	Industry	CR4	CR8	HHI	Number of Companies	Number of Facilities
331	Primary Metal Manufacturing	13.8	22.3	97.4	4,076	5,059

Sources: U.S. Department of Commerce, Bureau of the Census. 2001. *1997 Economic Census, Manufacturing Subject Series: Concentration Ratios in Manufacturing*. Washington, DC: Government Printing Office.

In the 1990s, many of the larger mills and operations closed down to save costs, and this is reflected in the 1997 size distribution of facilities (see Table 6-29). Nearly 73 percent of facilities in the industry employed fewer than 100 people, but these firms accounted for only 12 percent of sales. The average company in this industry operates 1.24 facilities.

Table 6-29. Size of Establishments and Value of Shipments for the Primary Metal Manufacturing Industry (NAICS 331)

	1997	
Number of Employees in Establishment	Number of Facilities	Value of Shipments ($\$10^6$)
1 to 4 employees	859	272.9
4 to 9 employees	502	(D)
10 to 19 employees	621	(D)
20 to 49 employees	979	6,199.6
50 to 99 employees	720	11,084.9
100 to 249 employees	797	30,211.1
250 to 499 employees	363	35,126.8
500 to 999 employees	145	29,829.8
1,000 to 2,499 employees	55	25,247.2
2,500 or more employees	18	28,107.6
Total	5,059	168,117.7

(D) = undisclosed
Sources: U.S. Department of Commerce, Bureau of the Census. 2002a. *1997 Economic Census, Manufacturing Subject Series, General Summary.* Washington, DC: Government Printing Office.

Over the 5-year period of 1997 through 2001, facilities produced at levels between 70 and 84 percent of their full production capacity (Table 6-30). The average level for the 5 years was 77.4, and it fell by 17 percent over the time period.

Table 6-30. Capacity Utilization Ratios for the Primary Metal Manufacturing Industry, 1997–2001

1997	1998	1999	2000	2001
84	78	81	74	70

Note: All values are percentages.
Source: U.S. Department of Commerce, Bureau of the Census. 2003b. *Current Industry Reports, Survey of Plant Capacity, 2001.* Washington, DC: Government Printing Office.

6.7.4 Markets and Trends

As with many other industries, the steel mill products felt the strain of the Asian financial crisis in the late 1990s. Despite dramatic action by the U.S. Department of Commerce in 1999, global demand for U.S. steel mill products and nonferrous metal products decreased, reflected by the decline in the value of shipments for the industry (see Table 6-31). Between 1997 and 2001, the industry's value of shipments decreased 17.8 percent.

Table 6-31. Value of Shipments for the Primary Metal Manufacturing Industry (NAICS 331), 1997–2001

Year	Value of Shipments ($\$10^6$)
1997	168,118
1998	166,109
1999	156,647
2000	156,598
2001	138,245

Sources: U.S. Department of Commerce, Bureau of the Census. 2003a. *Annual Survey of Manufactures, 2001*. Washington, DC: Government Printing Office.

In 1999, industry experts predicted that domestic demand for steel would be strong through 2004, assuming moderate growth in the U.S. economy. In terms of the global market, analysts predict that worldwide demand will increase. The growth in worldwide demand should help the domestic industry because foreign producers will be able to ship their steel to places other than the United States. The steel market performance depends on growth in the highway and private nonresidential building markets, which are both projected to experience growth through the first part of the 21st century (Bell, 1999).

Domestic aluminum production in the near future will likely not meet domestic demand, which will increase U.S. reliance on aluminum imports. Growth in the transportation sector, especially light vehicles, is the driving force behind demand for aluminum products (Cammarota, 1999). Copper production is projected to decline through the early part of the 21st century, but consumption should follow the growth patterns of the U.S. economy. The construction and power utilities industries represent the main domestic consumers of copper (Shaw, 1999). The projected increase in lead-acid batteries should boost the lead production increase. Industry analysts predict an average annual growth rate of 11 percent in the industrial battery market, due mostly in part to strong performance in the telecommunications and uninterruptible power supply markets. Finally, zinc production should grow along with the economy then slow at the beginning of the 21st century. Growth in sales in the galvanizing segment should support zinc production (Larrabee, 1999a, 1999b).

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CHAPTER 7

COST, ECONOMIC, AND ENERGY IMPACTS

This chapter reports the cost, economic, and energy impact analysis performed for the final BART rule. EPA used the IPM, developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for SO_2 and NO_x throughout the contiguous United States for the entire power system. Documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm.

7.1 Modeling Background

The analysis presented here covers fossil-fuel-fired steam electric plants (part of the electric power sector), which are one of the 26 stationary source categories that are BART-eligible.

The analysis presents results for three scenarios of increasing stringency for BART for EGUs. In this rule, EPA is setting presumptive limits for a subset of the BART-eligible, coal-fired EGUs (those greater than 200 MW at plants greater than 750 MW) and strong recommendations for another subset of BART-eligible coal-fired EGUs (units greater than 200 MW at plants less than 750 MW). However, it is up to States to ultimately decide on what BART is for their affected units. The three scenarios represent different assumptions regarding the ultimate levels of controls imposed by States on BART-eligible EGUs, and these scenarios are summarized in Table 7-1.

EPA assumes that the CAIR program is in the baseline for this final BART rule analysis. EPA further assumes that States implement the required CAIR reductions through a cap-and-trade program. For CAIR SO_2 and NO_x controls, EPA modeled an annual, two-phased control strategy for 26 eastern States and the District of Columbia (see Figure 7-1). For NO_x, separate ozone season caps were applied to Connecticut and Massachusetts. See Table 7-2 for total annual emissions caps under CAIR.

Table 7-1. BART Scenarios Modeled in IPM

	Scenario 1	Scenario 2	Scenario 3
NO_x	Combustion controls on all units ≥200 MW at plants >750 MW Annual operation of SCR (where existing) No controls on O/G steam	Combustion controls on units ≥200 MW SCR on cyclone units >200 Annual operation of SCR (where existing) No controls on O/G steam	SCR on units ≥100 MW Combustion controls on 25 MW ≤ units ≤100 MW Annual operation of SCR (where existing) No controls on O/G steam
SO_2	95% reduction or 0.15 lbs/MMBtu on all previously uncontrolled units ≥200 MW at plants >750 MW No controls on units with existing scrubbers No controls on oil units No additional controls (beyond those for WRAP) on units in five 309 States: Arizona, Utah, Oregon, Wyoming, and New Mexico.	95% reduction or 0.15 lbs/MMBtu on all previously uncontrolled units ≥200 MW No controls on units with existing scrubbers No controls on oil units No additional controls (beyond those for WRAP) on units in five 309 States: Arizona, Utah, Oregon, Wyoming, and New Mexico.	95% reduction or **0.10** lbs/MMBtu on all previously uncontrolled units ≥100 MW No controls on units with existing scrubbers No controls on oil units No additional controls (beyond those for WRAP) on units in five 309 States: Arizona, Utah, Oregon, Wyoming, and New Mexico.

Note: For modeling, SO_2 controls would require a 95 percent reduction *from the 2005 base case SO_2 rate.*

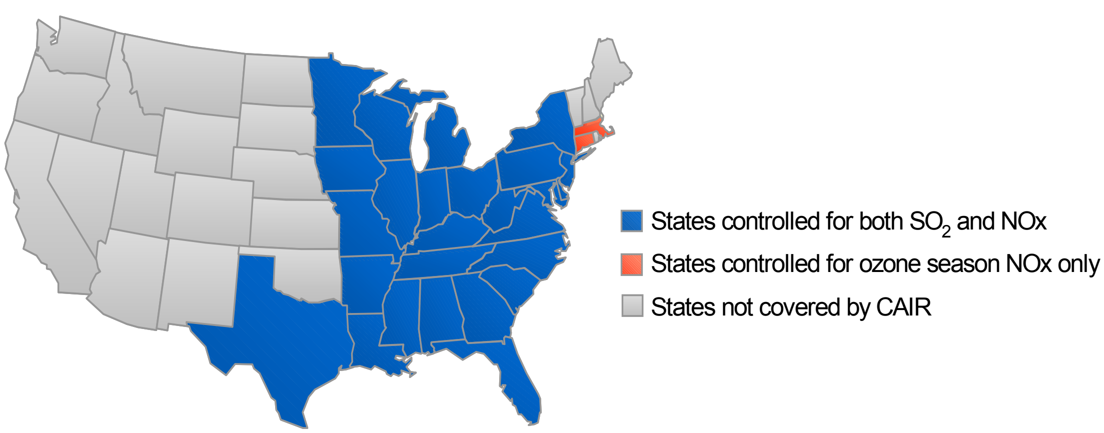

Figure 7-1. CAIR Modeled Region

Table 7-2. CAIR Annual Emissions Caps (Million Tons)

	2010–2014 (2009–2014 for NO_x)	2015–Thereafter
SO_2	3.6	2.5
NO_x	1.5	1.3

BART-eligible units were defined as those that were online after August 7, 1962, and under construction prior to August 7, 1977. EPA has developed an updated list of coal-fired BART-eligible coal units by more accurately determining which units with on-line dates after 1978 were BART-eligible. A description of how this was done, along with a complete list of BART-eligible coal-fired EGU sources used in the modeling, can be found in Appendix A and Appendix B, respectively. The new list represents 491 units (ranging in size from 29 MW to 1,300 MW) totaling 218 GW of capacity, representing more than half of the total coal-fired EGU capacity in the United States. Of these, a smaller portion (99 units totaling almost 45 GW) are in States that are not in the final CAIR region for PM (which requires annual controls of SO_2 and NO_x). Almost 17 GW of these are in the 309 WRAP States. A number of units have already installed SO_2 and NO_x controls. Which of these units are required to apply controls depends on the modeling scenario. A characterization of the complete list of BART-eligible coal units is provided in Table 7-3.

Table 7-3. Number of Coal-Fired EGU BART-Eligible Units

	Plant Size		
Unit Size	**<750 MW**	**>750 MW**	**Total**
CAIR Region			
<200 MW	97		97
>200 MW	61	234	295
CAIR Total	158	234	392
Non-CAIR Region			
<200 MW	24		24
>200 MW	22	53	75
Non-CAIR Total	46	53	99
Total	204	287	491

In the analysis, controls and reductions were assumed to be required in 2015, a date that is generally consistent with the expected timing of the rule. States must submit SIPs relevant to the BART requirements in January 2008. After approval of the SIP, there is a 5-year compliance date. Thus, controls are likely to be installed by the end of 2013 or the beginning of 2014 to comply with the rule. Additionally, facilitating the analysis, EPA had existing inventories, modeling, and base case runs for 2015.

In our modeling, no additional necessary controls for SO_2 (beyond their WRAP obligations) were assumed for any units within the five WRAP 309 States. Also, because of modeling limitations, no additional reductions were assumed from units with existing scrubbers, even if they were performing at less than 95 percent removal. This assumption would tend to understate the costs and emission reductions of the rule.

These scenarios differ from the modeling done in the original BART proposal. In modeling the proposed BART, SO_2 affected units were given the choice of meeting a 0.10 lbs/mmBtu emission rate or achieving 90 percent reductions from base emissions. Affected units needed to meet a 0.2 lbs/mmBtu emission rate limit for NO_x. Additionally in the proposal, EPA required controls only on BART-eligible units greater than 250 MW.

Additionally, the final CAIR rule differs from this modeling in that it requires annual SO_2 and NO_x reductions in 23 States and the District of Columbia and ozone season NO_x reductions in 25 States and the District of Columbia. Many of the CAIR States are affected by both the annual SO_2 and NO_x reduction requirements and the ozone season (May through September) NO_x requirements.

Consequently, EPA's modeling of CAIR in this BART analysis is similar, but not identical to, the final CAIR requirements. EPA modeling included three additional States (Arkansas, Delaware, and New Jersey) within the CAIR region and required these States to make annual SO_2 and NO_x reductions. These three States are not required to make annual reductions under the final CAIR. Along with finalizing CAIR, EPA has also put forth a proposal to include Delaware and New Jersey in the CAIR region for annual SO_2 and NO_x reductions. Arkansas is not included in the annual SO_2 and NO_x requirements either as part of Final CAIR or the "Proposed Rule" (but is included for the ozone season CAIR requirement). The model run also included individual State ozone season NO_x caps for Connecticut and Massachusetts and did not include ozone season NO_x caps for any other CAIR States.

The air quality and benefits analyses done in support of CAIR are based on emission projections from the initial IPM run with Arkansas, Delaware, and New Jersey included for annual SO_2 and NO_x.

EPA believes that the differences between the initial IPM run and the final IPM run have limited impact on BART-projected control costs, emissions, and other impacts. Modeling the CAIR region without Arkansas, Delaware, and New Jersey does not change the results presented here in any significant way, and in any event, this generally reflects the geographic scope of the CAIR program as EPA intends it to be ultimately.

In assuming that CAIR is in the baseline, EPA also assumed, for the purposes of this analysis, that the CAIR trading program is "better than BART" and will substitute for source-specific BART in the CAIR-affected region with annual SO_2 and NO_x reduction requirements.[1] Source-specific BART controls were thus assumed for the ozone-season CAIR States only (Massachusetts and Connecticut in this modeling) and non-CAIR regions of the country.

EPA would note that its analysis of BART in this final rule differs from its analysis of BART in the CAIR Technical Support Document (TSD) "Demonstration that CAIR Satisfies the 'Better-than-BART' Test as Proposed in the Guidelines for Making BART Determinations." In that analysis, EPA assumed a more strict interpretation of BART nationwide[2] than in the final BART and compared it to a program that included CAIR together with a more strict interpretation of BART in the non-CAIR States.

Consequently, this analysis does not assume BART source-specific controls for BART-eligible units in Arkansas, Delaware, and New Jersey (although they are covered for seasonal NO_x under final CAIR). As noted, sources in Delaware and New Jersey, however, would be covered by the Delaware and New Jersey proposal, which if it were finalized, would have the effective impact of bringing them into the CAIR trading program.

Arkansas was included in CAIR with a 2015 SO_2 budget of 34,091 tons—corresponding to a 63,309-ton reduction in SO_2 emissions relative to Title IV allocations. Under our modeling of CAIR, however, sources in Arkansas did not put on SO_2 controls and did not make SO_2 reductions so that all of the required SO_2 reductions from Arkansas were accomplished in other States. Consequently, with Arkansas not included in CAIR, SO_2 emissions in the other CAIR States would increase. Arkansas has 3,100 MW of BART-eligible coal units without scrubbers (totaling over 62,000 tons of SO_2 emissions in 2001). BART would require 95 percent controls (or a 0.15 lb/mmBtu emission rate) from these sources. Although total reductions would be relatively similar under both CAIR and BART, all the reductions would take place in Arkansas under BART, while all of the reductions would take place in other CAIR States under CAIR.

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1 EPA is making such a determination in this rulemaking.

2 The interpretation of BART modeled in the CAIR TSD assumed an SO_2 limit of 90 percent or 0.10 lb/mmBtu to all coal units greater than 100 MW and a NO_x limit of 0.20 lb/mmBtu on all coal units greater than 25 MW.

Applying source-by-source BART nationally—together with the CAIR program in the CAIR region—would not be expected to achieve additional emissions reductions. Rather it would force controls in the CAIR region at specific BART units, which do not necessarily represent the least cost reductions in the region. Consequently, such an approach would only serve to shift around emissions within the CAIR region and increase total program costs.

IPM has been used for evaluating the economic and emission impacts of environmental policies for over a decade. The model's base case incorporates title IV of the Clean Air Act (the Acid Rain Program), the NO_x SIP Call, various New Source Review (NSR) settlements, and several State rules affecting emissions of SO_2 and NO_x that were finalized prior to April 2004. The NSR settlements include agreements between EPA and Southern Indiana Gas and Electric Company (Vectren), Public Service Enterprise Group, Tampa Electric Company, We Energies (WEPCO), Virginia Electric & Power Company (Dominion), and Santee Cooper. IPM also includes various current and future State programs in Connecticut, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, New York, Oregon, Texas, and Wisconsin. IPM includes State rules that have been finalized and/or approved by a State's legislature or environmental agency.

The economic modeling presented in this chapter has been developed for specific analyses of the power sector. Thus, the model has been designed to reflect the industry as accurately as possible. As a result, EPA has used discount rates in IPM that are appropriate for the various types of investments and other costs that the power sector incurs. The discount rates used in IPM may differ from discount rates used in other EPA analyses done for BART, particularly the discount rates used in the benefits analysis that are assumed to be social discount rates. EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the discount rates used for power sector modeling. These discount rates have undergone review by the power sector and the Energy Information Administration. EPA's discount rate approach has not been challenged in court.

More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (www.epa.gov/airmarkets/epa-ipm).

7.2 Projected SO_2 and NO_x Emissions and Reductions

The projected emissions levels under CAIR and under the three different BART scenarios are provided in Table 7-4.

Table 7-4. Projected Emissions of SO_2 and NO_x with CAIR and with BART (thousand tons from units greater than 25MW)

	2015			
	CAIR	CAIR + BART (Scenario 1)	CAIR + BART (Scenario 2)	CAIR + BART (Scenario 3)
SO_2 (annual)	4,890	4,836	4,770	4,738
NO_x (annual)	2,125	2,009	1,916	1,693

Note: The emissions data presented here are EPA modeling results. "CAIR +BART" national emissions assume BART applied only in those States not included in CAIR for PM.

7.3 Projected Costs, Control Technology, and Fuel Costs

For the modeled region, EPA projects that the annual incremental costs of Scenario 2 BART are $97 million in 2010 and $436 million in 2015 (in $1999, see Table 7-5). In 2020, the annual costs are $439 million. Costs under Scenario 3 were at $896 million in 2015, while they are $253 million in 2015 under Scenario 1.

Table 7-5. Annualized Cost of BART

Annualized Cost ($1999 millions)	2010	2015	2020
Scenario 1	$87	$253	$283
Scenario 2	$97	$436	$429
Scenario 3	$92	$896	$853

Source: Integrated Planning Model run by EPA.

Note: Changes occur in 2010 as people react to the policy announcement, in anticipation of future effects.

It should be kept in mind that the cost of electricity generation represents roughly one-third to one-half of total electricity costs, with transmission and distribution costs representing the remaining portion. The impact of this rule on retail electricity prices, faced by consumers, is shown in a later table.

Under Scenario 2, BART is projected to result in the installation of an additional 6.2 GW of flue gas desulfurization (scrubbers) on existing coal-fired generation capacity for SO_2 control in 2015 (relative to CAIR). For NO_x control, this BART scenario is also projected to result in an additional 24 GW of combustion control equipment and 2.4 GW of selective catalytic reduction technology (SCR) on cyclone-boiler coal-fired generation capacity by 2015 (see Table 7-6).

Table 7-6. National Pollution Controls by Technology under BART (GW)

	Incremental Retrofits under BART								
	Scenario 1			Scenario 2			Scenario 3		
Technology	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**
Combustion Controls		19.0			24.0			26.0	
Scrubbers	0.1	3.4	4.3	0.0	6.2	5.8	0.2	7.7	6.9
SCR	0.1	0.2	0.3	0.4	2.4	2.6	0.3	27.2	27.3

Note: Numbers may not add due to rounding. CAIR retrofits (CAIR is included in the baseline) include existing scrubbers and SCR as well as additional retrofits for NSR settlements and various State rules.

Source: Integrated Planning Model run by EPA.

Coal-fired generation (as well as coal production) and natural gas-fired generation under BART are projected to remain essentially unchanged in 2010 and 2015 relative to CAIR levels. None of the BART scenarios are expected to cause any additional capacity to be uneconomic to maintain. It is also not expected that BART will change the composition of new generation built to meet future growth in electric demand. BART is not expected to affect coal prices or natural gas prices.

7.4 Projected Retail Electricity Prices

Retail electricity prices are projected to increase by small amounts in the regions of the country that are modeled as affected by BART, such as MAPP, SPP, and RM. Electricity prices in the CAIR region are expected to be essentially unchanged with implementation of BART controls outside the borders of CAIR (see Table 7-7 and Figure 7-2).

Table 7-7. Retail Electricity Prices by NERC Region with CAIR and with BART (Mills/kWh)

Power Region	Main States Included	2000	CAIR		Scenario 2 BART		Percentage Price Change	
			2015	2020	2015	2020	2015	2020
ECAR	OH, MI, IN, KY, WV, PA	57.4	58.5	58.0	58.4	58.0	–0.1%	0.0%
ERCOT	TX	65.1	64.6	63.3	64.6	63.3	0.1%	0.0%
MAAC	PA, NJ, MD, DC, DE	80.4	71.7	72.8	71.7	72.8	–0.1%	0.1%
MAIN	IL, MR, WI	61.2	60.3	62.0	60.2	62.0	–0.1%	0.0%
MAPP	MN, IA, SD, ND, NE	57.4	49.6	48.0	50.3	48.7	1.5%	1.5%
NY	NY	104.3	88.8	88.4	88.8	88.4	0.0%	0.0%
NE	VT, NH, ME, MA, CT, RI	89.9	84.7	83.0	84.8	83.0	0.1%	0.0%
FRCC	FL	67.9	72.3	70.5	72.3	70.5	0.0%	0.0%
STV	VA, NC, SC, GA, AL, MS, TN, AR, LA	59.3	56.2	56.6	56.2	56.6	–0.1%	–0.1%
SPP	KS, OK, MR	59.3	57.5	57.0	57.9	57.4	0.7%	0.7%
PNW	WA, OR, ID	45.9	47.5	46.9	47.5	46.9	0.0%	0.0%
RM	MT, WY, CO, UT, NM, AZ, NV, ID	64.1	65.6	65.4	65.9	65.7	0.5%	0.4%
CALI	CA	94.7	99.1	99.5	99.1	99.5	0.0%	0.0%
NATIONAL	Contiguous Lower 48 States	66.0	64.4	64.3	64.5	64.4	0.1%	0.1%

Source: EPA's Retail Electricity Price Model. 2000 prices are from EIA's AEO 2003.

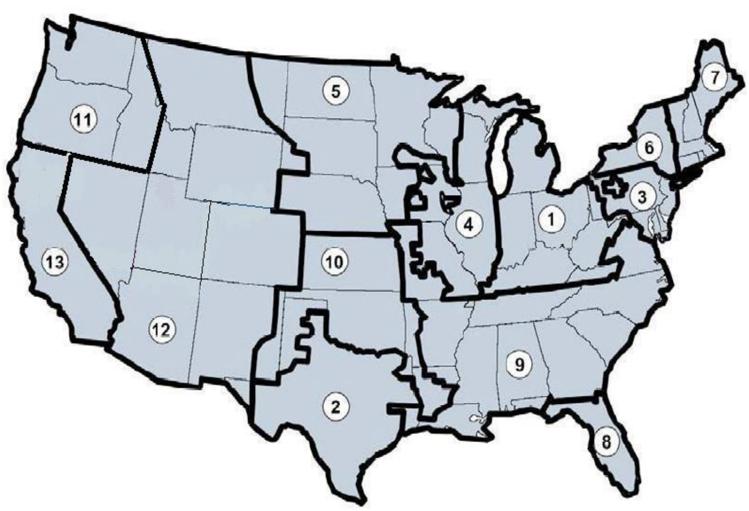

Figure 7-2. NERC Power Regions

7.5 Key Differences in EPA Model Runs for Final BART Modeling

As previously stated, the emissions, cost, air quality, and benefits analyses done for the final BART are from a modeling scenario that assumes CAIR to require annual SO_2 and NO_x reductions in 26 States and the District of Columbia and ozone season NO_x requirements in Connecticut and Massachusetts (see Figure 7-1). This modeling differs from what would reflect final BART, in that Arkansas, Delaware, and New Jersey are not included in the annual SO_2 and NO_x requirements; thus, they would no longer be considered part of a trading program that is better than source-specific BART. BART-eligible EGUs in these States would consequently be modeled to comply with source-specific BART (see Figure 7-3). Additionally, the final BART modeling should reflect the Clean Air Mercury Rule, which imposes a 38-ton mercury cap by 2010 and a 15-ton cap by 2018.

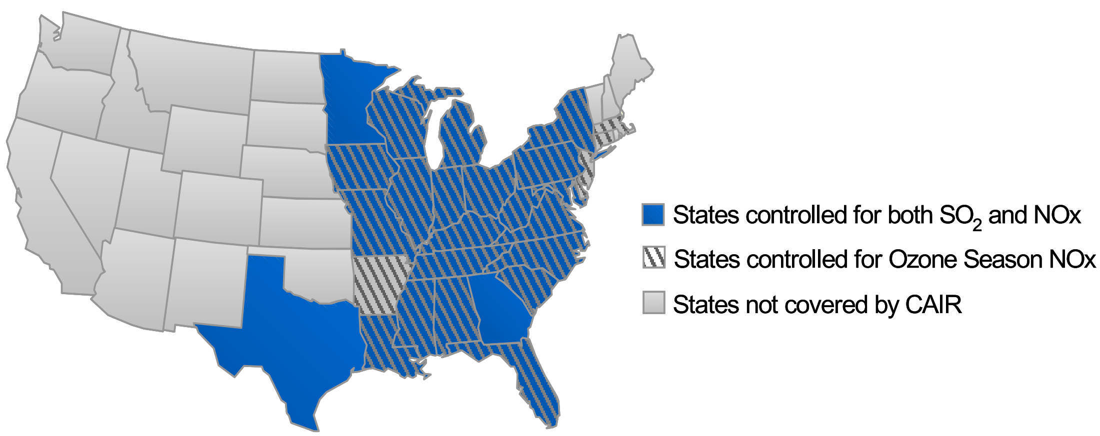

Figure 7-3. Final CAIR Region

Note: Delaware and New Jersey are not included in the Final CAIR for the annual SO_2 and NO_x requirements. However, EPA intends on incorporating these two States in the annual CAIR program through a separate rulemaking. See earlier discussion for more detail.

All IPM runs done in support of BART and used as part of the final BART package are in the final CAIR docket and can be found on EPA's Web site: http://www.epa.gov/airmarkets/epa-ipm/iaqr.html. A complete list of IPM runs can be found in Appendix D of this RIA.

7.6 Limitations of Analysis

EPA's modeling is based on its best judgment for various input assumptions that are uncertain. Assumptions for future fuel prices and electricity demand growth generally get particular attention because of the importance of these two key model inputs to the power sector.

However, for this rule (which is not market based and involves source-specific installation of controls) EPA believes that scenarios with higher gas price and demand assumptions would not change the assessment of costs. As a general matter, the Agency selects the best available information from available engineering studies of air pollution controls and has set up what it believes is the most reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory controls.

The annualized cost estimates of the private compliance costs that are provided in this analysis are meant to show the increase in production (engineering) costs of BART to the power sector. In simple terms, the private compliance costs that are presented are the annual increase in revenues required for the industry to be as well off after BART is implemented as before. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that is commonplace in economic analysis of power sector costs for estimating engineering costs in annual terms. For estimating annualized costs, EPA has applied a capital recovery factor (CRF) multiplier to capital investments and added that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of BART.

The annualization factor used for pure social cost calculations (for annualized costs) normally includes the life of capital and the social discount rate. For purposes of benefit-cost analysis of this rule, EPA has calculated the annualized social costs using the discount rates from the benefits analysis for BART (3 percent and 7 percent and a 30-year life of capital). The cost of added insurance necessary because of BART was included in the calculations, but local taxes were not included because they are considered to be transfer payments and not a social cost. Using these discount rates, the social costs of Scenario 2 BART are $248 million in 2015 (with $119 million for Scenario 1 BART and $567 million for Scenario 3 BART) using a discount rate of 3 percent. Using a discount rate of 7 percent, the social costs of Scenario 2 BART are $297 million in 2015 (with $141 million for Scenario 1 BART and $688 million for Scenario 3 BART).

The annualized regional cost of BART, as quantified here, is EPA's best assessment of the cost of implementing source-specific BART in the non-CAIR region. These costs are generated from rigorous economic modeling of changes in the power sector due to BART. This type of analysis using IPM has undergone peer review and federal courts have upheld regulations covering the power sector that have relied on IPM's cost analysis.

The direct private compliance cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. EPA believes that the cost assumptions used for BART reflect, as closely as possible, the best information available to the Agency today.

Furthermore, EPA wants to identify some unquantified costs as limits to its analysis. These costs include the costs of state administration of the program, which we believe are modest. There also may be unquantified costs of transitioning to BART, such as the costs associated with the possible retirement of smaller or less-efficient EGUs and employment shifts as workers are retrained at the same company or reemployed elsewhere in the economy.

Cost estimates for BART are based on results from ICF's IPM. The model minimizes the costs of producing electricity (including abatement costs) while meeting load demand and other constraints (full documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm). The structure of the model assumes that the electric utility industry will be able to meet the BART requirements at least cost. Utilities in the IPM model also have "perfect foresight." To the extent that utilities misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

From another vantage point, this modeling analysis does not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal as well as reductions in their costs over time. As an example, recent cost estimates of the Acid Rain SO_2 trading program by Resources for the Future (RFF) and MIT's Center for Energy and Environmental Policy Research (CEEPR) have been as much as 83 percent lower than originally projected by EPA (see Carlson et al. [2000] and Ellerman [2003]). It is important to note that the original analysis for the Acid Rain Program done by EPA also relied on an optimization model like IPM. *Ex ante*, EPA cost estimates of roughly \$2.7 to \$6.2 billion[3] in 1989 were an overestimate of the costs of the program in part because of the limitation of economic modeling to predict technological improvement of pollution controls and other compliance options such as fuel switching. *Ex post* estimates of the annual cost of the Acid Rain SO_2 trading program range from \$1.0 to \$1.4 billion. Harrington et al. have examined cost analyses of EPA programs and found a tendency for predicted costs to overstate actual implementation costs in market-based programs (Harrington, Morgenstern, and Nelson, 2000). In recognition of the possibility of technological improvement, EPA's mobile source program uses adjusted engineering cost estimates of pollution control equipment and installation costs to

[3] 2010 Phase II cost estimate in \$1995.

account for this fact, which EPA has not done in this case.[4] It is expected that a cap and trade approach to BART would provide greater incentives for technology innovations than the command and control approach analyzed here.

It is also important to note that the capital cost assumptions for scrubbers used in EPA modeling applications are highly conservative. These are a substantial part of the compliance costs. Data available from recent published sources show the reported FGD costs from recent installations to be below the levels projected by IPM.[5] In addition, EPA also conducted a survey of recent FGD installations and compared the costs of these installations to the costs used in IPM. This survey included small, mid-size, and large units. Examples of the comparison of these referenced published data with the FGD capital cost estimates obtained from IPM are provided in the Final CAIR docket.

EPA's latest update of IPM incorporates State rules or regulations adopted before March 2004 and various NSR settlements. Documentation for IPM can be found at www.epa.gov/airmarkets/epa-ipm. Any State or settlement action since that time has not been accounted for in our analysis in this chapter.

As configured in this application, the IPM model does not take into account demand response (i.e., consumer reaction to electricity prices). Any increased retail electricity prices would prompt end users to curtail (to some extent) their use of electricity and encourage them to use substitutes.[6] The response would lessen the demand for electricity, resulting in electricity price increases even lower than IPM predicts, which would also reduce generation and emissions. Because of demand response, certain unquantified negative costs (i.e., savings) result from the reduced resource costs of producing less electricity because of the lower quantity demanded. To some degree, these saved resource costs will offset the additional costs that we would anticipate with BART. Although the reduction in electricity use is likely to be very small, the cost savings from such a large industry ($250 billion in revenues in 2003) may be substantial.

Recent research suggests that the total social costs of a new regulation may be affected by interactions between the new regulation and preexisting distortions in the economy, such as taxes. In particular, if cost increases due to a regulation are reflected in a general increase in the

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[4] See recent regulatory impact analysis for the Tier 2 regulations for passenger vehicles (1999) and Heavy-Duty Diesel Vehicle Rules (2000). There is also evidence that scrubber costs will decrease in the future because of the learning-by-doing phenomenon, as more scrubbers are installed (see Manson, Nelson, and Neumann [2002]).

[5] There is also evidence that scrubber costs will decrease in the future because of the learning-by-doing phenomenon, as more scrubbers are installed (see Manson, Nelson, and Neumann [2002]).

[6] The degree of substitution/curtailment depends on the price elasticity of demand for electricity.

price level, the real wage received by workers may be reduced, leading to a small fall in the total amount of labor supplied. This "tax interaction effect" may result in an increase in deadweight loss in the labor market and an increase in total social costs. Although there is a good case for the existence of the tax interaction effect, recent research also argues for caution in making prior assumptions about its magnitude. However, there are currently no government-wide economic analytical guidelines that discuss the tax interaction effect and its potential relevance for estimating federal program costs and benefits. The limited empirical data available to support quantification of any such effect lead to this qualitative identification of the costs.

On balance, after considering various unquantified costs (and savings that are possible), EPA believes that the annual private compliance costs that we have estimated are more likely to overstate the future annual compliance costs that industry will incur, rather than understate those costs.

7.7 IPM Runs for CAIR Better-than-BART Determination

The IPM runs used in the final determination that CAIR is better than BART differed slightly from the IPM runs used in this RIA. The IPM runs used for the final CAIR-is-better-than-BART determination reflect the final CAIR region (New Jersey, Delaware, and Arkansas affected only by the CAIR ozone season program). This change was not included in the IPM runs used for this RIA because of time constraints. As discussed previously, EPA does not believe this modification would have had a significant impact on the RIA. See the CAIR-is-better-than-BART determination section of this rulemaking for further discussion.

7.8 References

Carlson, Curtis, Dallas R. Burtraw, Maureen Cropper, and Karen L. Palmer. 2000. "Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade?" *Journal of Political Economy* 108(6):1292-1326.

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Harrington, W., R.D. Morgenstern, and P. Nelson. 2000. "On the Accuracy of Regulatory Cost Estimates." *Journal of Policy Analysis and Management* 19(2):297-322.

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SECTION 8

RESULTS OF COST, EMISSIONS REDUCTIONS, AND ECONOMIC IMPACT ANALYSES FOR NONELECTRICITY GENERATING UNITS

This chapter presents the results of the cost analyses for the non-EGU sources in BART source categories covered in these analyses. The cost analyses evaluate the potential impacts associated with the final BART rule, based on assumptions about how the States may implement controls for non-EGU sources. As mentioned in Chapter 3, there are 25 non-EGU source categories that are to be considered for controls associated with the BART program. Section 8.1 presents a short summary of the results of the impact analyses. Section 8.2 provides summaries of the results of these analyses across sources categories. Section 8.3 presents a description of the methodological approach for these cost analyses, the scenarios that are analyzed, and important assumptions and details that underlie the costs and emission reductions for each scenario. Section 8.4 mentions the control technologies that are applied to the non-EGU source categories in this analysis. Section 8.5 provides a list of the source categories affected and summaries of analysis results by BART source category. Section 8.6 presents a listing of caveats and limitations associated with the cost analyses. More detailed results for the scenarios considered are provided in the technical support document for these analyses (E.H. Pechan, 2005) and in Appendix B of this RIA.

8.1 Results in Brief

The results for applying the scenarios examined for controlling 2015 SO_2 and NO_x emissions at non-EGU BART-eligible units range from 83,778 to 378,169 tons of SO_2 and from 165,634 to 391,101 tons of NO_x nationwide for costs annualized at a 7 percent discount rate. For costs annualized at a 3 percent discount rate, the reduction of SO_2 emissions in 2015 ranges from 132,279 to 373,797 tons and the reduction of NO_x emissions in 2015 ranges from 246,607 to 393,349 tons. Annualized costs associated with these reductions in 2015 range from $151.43 million to $2.24 billion (1999$) for costs estimated at a 7 percent discount rate and from $272.23 million to $1.8 billion (1999$) for costs estimated at a 3 percent discount rate. The capital costs associated with these reductions in 2015 range from $655.70 million to $14.75 billion for costs estimated at a 7 percent discount rate and from $1.9 billion to $12.73 billion.

8.2 Summary of Results for Nonelectricity Generating Sources

In this RIA chapter, three illustrative scenarios are applied to non-EGU BART-eligible sources. Costs and emissions reductions for these sources are estimated for these annualized costs per ton scenarios for reducing SO_2 and NO_x at varying levels of stringency: $1,000, $4,000, and $10,000.[1] These scenarios, called Scenarios 1, 2, and 3 respectively, are applied nationwide and are presented in detail in this chapter. These scenarios are meant to be illustrative of the potential alternatives that may be available to States as they consider what scenarios to include in their SIPs for non-EGU sources. These scenarios are also compliant with the requirement in OMB Circular A-4 to examine alternative levels of stringency as part of an RIA. Detailed results for two other illustrative scenarios, annualized cost per ton of $2,000 and $3,000, are found in Appendix G.

This section includes several summary tables in which the emission reductions and costs for all non-EGU scenarios applied are shown by source category and also by the discount rate for the annualized costs. Table 8-1 summarizes the SO_2 emission reductions for the analyses to the BART non-EGU source categories using a discount rate of 7 percent and also showing results using an discount rate of 3 percent. In total, the scenarios applied in this analysis lead to nationwide SO_2 emission reductions ranging from 83,778 tons to 378,169 tons with costs at a 7 percent discount rate. These scenarios lead to SO_2 emission reductions ranging from 132,280 to 373,798 tons with costs at a 3 percent rate. These represent a reduction of 11 to 30 percent from the 2015 baseline. For scenario 2, the SO_2 emission reduction estimate is 269,992 tons or a 22 percent reduction from the 2015 baseline with costs at a 7 percent discount rate and 290,591 tons or a 24 percent reduction from the 2015 baseline with costs at a 3 percent discount rate.

Table 8-2 summarizes the NO_x emission reductions. The nationwide NO_x emission reductions from applying these three scenarios range from 165,634 tons to 391,101 tons with costs at a 7 percent discount rate. These represent a reduction of 24 to 57 percent from the 2015 baseline. These scenarios lead to NO_x emission reductions ranging from 246,067 to 393,349 tons with costs at a 3 percent rate. These represent a reduction of 36 to 58 percent from the 2015 baseline. For scenario 2, the NO_x emission reduction estimate is 361,152 tons

[1] Analysis of non-EGU sources considers the application of controls at the source category level up to a specified average cost per ton cutoff.

Table 8-1. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons)		
			Scenario 1	Scenario 2	Scenario 3
Industrial boilers	420,782	7%	32,213	151,387	200,308
	420,782	3%	65,783	164,438	204,217
Petroleum refineries	199,483	7%	2,097	31,319	56,462
	199,483	3%	17,033	41,911	58,525
Kraft pulp mills	119,818	7%	0	10,814	28,380
	119,818	3%	0	3,196	14,610
Portland cement plants	116,835	7%	0	13,383	26,716
	116,835	3%	0	18,326	30,690
Hydrofluoric, sulfuric, and nitric acid plants	96,741	7%	34,140	36,753	36,753
	96,741	3%	34,140	36,753	36,753
Chemical process plants	47,700	7%	0	2,376	3,571
	47,700	3%	0	2,376	3,571
Iron and steel mills	23,541	7%	0	2,914	2,914
	23,541	3%	0	2,914	2,914
Coke oven batteries	9,815	7%	0	4,088	6,107
	9,815	3%	0	3,724	5,564
Sulfur recovery plants	59,766	7%	13,697	13,697	13,697
	59,766	3%	13,693	13,693	13,693
Primary aluminum ore reduction plants	47,552	7%	1,630	3,260	3,260
	47,552	3%	1,630	3,260	3,260
Lime kilns	9,373	7%	0	0	0
	9,373	3%	0	0	0

(continued)

Table 8-1. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons)		
			Scenario 1	Scenario 2	Scenario 3
Glass fiber processing plants	2,170	7%	0	0	0
	2,170	3%	0	0	0
Municipal incinerators	284	7%	0	0	0
	284	3%	0	0	0
Coal cleaning plants	1,530	7%	0	0	0
	1,530	3%	0	0	0
Carbon black plants	41,853	7%	0	0	0
	41,853	3%	0	0	0
Phosphate rock processing plants	21	7%	0	0	0
	21	3%	0	0	0
Secondary metal production facilities	9,988	7%	0	0	0
	9,988	3%	0	0	0
Total	1,208,088	7%	83,778	236,992	378,169
	1,208,088	3%	132,279	290,591	373,797

or a 53 percent reduction from the 2015 baseline with costs at a 7 percent discount rate and 390,871 tons or a 57 percent reduction from the 2015 baseline with costs at a 3 percent discount rate.

Table 8-3 summarizes the annualized costs associated with the three non-EGU scenarios. In total, the three scenarios applied in this analysis have annualized costs of $151.43 million to $2.2 billion (1999$) with costs at a 7 percent discount rate and $272.34 million to $1.8 billion (1999$) with costs at a 3 percent discount rate. The capital costs for these three scenarios range from $655.70 million to $14.75 billion for costs estimated at a 7 percent discount rate and from $1.9 billion to $12.73 billion for costs estimated at a 3 percent discount rate. More detailed capital cost information for these scenarios can be found in

Table 8-2. NO_x Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons)		
			Scenario 1	Scenario 2	Scenario 3
Industrial boilers	217,063	7%	67,325	130,456	130,522
	217,063	3%	111,939	130,424	130,505
Petroleum refineries	86,566	7%	4,035	47,556	51,316
	86,566	3%	4,579	51,259	53,005
Kraft pulp mills	103,614	7%	35,249	61,418	65,776
	103,614	3%	53,729	65,792	65,797
Portland cement plants	120,567	7%	19,276	54,601	71,921
	120,567	3%	30,903	71,921	71,921
Hydrofluoric, sulfuric, and nitric acid plants	17,059	7%	11,276	11,283	11,283
	17,059	3%	11,276	11,283	11,283
Chemical process plants	72,577	7%	23,970	34,636	34,801
	72,577	3%	27,142	34,801	34,801
Iron and steel mills	20,963	7%	1,036	6,997	8,507
	20,963	3%	1,036	8,500	8,673
Coke oven batteries	10,389	7%	0	5,768	5,768
	10,389	3%	0	5,768	5,768
Sulfur recovery plants	651	7%	135	141	141
	651	3%	135	141	141
Primary aluminum ore reduction plants	1,676	7%	50	253	255
	1,676	3%	50	253	255
Lime kilns	12,849	7%	2,683	4,471	7,153
	12,849	3%	4,471	7,153	7,153

(continued)

Table 8-2. NO_x Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons)		
			Scenario 1	Scenario 2	Scenario 3
Glass fiber processing plants	6,677	7%	568	2,116	2,198
	6,677	3%	775	2,116	2,198
Municipal incinerators	1,656	7%	0	744	744
	1,656	3%	0	744	744
Coal cleaning plants	1,110	7%	0	511	511
	1,110	3%	0	511	511
Carbon black plants	4,645	7%	7	120	120
	4,645	3%	7	120	120
Phosphate rock processing plants	719	7%	0	45	48
	719	3%	0	48	48
Secondary metal production facilities	1,377	7%	25	34	35
	1,377	3%	25	34	35
Total	681,765	7%	165,634	361,152	391,101
	681,765	3%	246,067	390,871	393,349

Appendix B. In addition, Appendix B contains sensitivity analyses that provide capital cost estimates based on a 10 percent rate for annualizing costs, and also other sensitivity analyses in that appendix examine the effects of variation in labor and energy rates on the costs. Finally, information on the number of affected BART-eligible units by scenario, pollutant, and source category are provided in Appendix B.

Given the highly capital-intensive nature of the control measures included in these analyses, it is not unreasonable that a lower discount rate would lead to more application of these measures to reduce SO_2 and NO_x and vice versa. More sources would be controlled that may not be able to control if they face relatively high interest rates for capital outlays in pollution control equipment. At scenario 1, the annualized costs and emission reductions are higher with a 3 percent discount rate than a 7 percent discount rate because the lower

Table 8-3. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$)

BART Source Category	Discount Rate	Scenarios		
		Scenario 1	Scenario 2	Scenario 3
Industrial boilers	7%	74.6	527.6	845.4
	3%	135.0	401.8	643.3
Petroleum refineries	7%	4.2	180.2	428.6
	3%	15.3	214.8	394.8
Kraft pulp mills	7%	20.7	141.7	313.3
	3%	45.6	106.3	168.5
Portland cement plants	7%	2.9	174.8	409.5
	3%	20.8	269.0	346.1
Hydrofluoric, sulfuric, and nitric acid plants	7%	18.0	23.4	23.4
	3%	16.4	21.4	21.4
Chemical process plants	7%	14.4	70.8	87.8
	3%	21.1	54.4	77.1
Iron and Steel mills	7%	0.6	23.5	33.2
	3%	0.4	22.7	32.4
Coke oven batteries	7%	0.0	18.7	33.8
	3%	0.0	14.9	25.0
Sulfur Recovery plants	7%	11.7	12.1	12.1
	3%	11.7	12.1	12.1
Primary aluminum ore reduction plants	7%	1.7	7.76	7.82
	3%	1.0	5.0	5.0
Lime kilns	7%	2.0	5.0	31.8
	3%	4.3	25.4	25.4

(continued)

Table 8-3. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$) (continued)

BART Source Category	Discount Rate	Scenarios		
		Scenario 1	Scenario 2	Scenario 3
Glass fiber processing plants	7%	0.5	5.3	7.8
	3%	0.7	4.8	6.8
Municipal incinerators	7%	0.0	1.1	1.1
	3%	0.0	0.9	0.9
Coal cleaning plants	7%	0.0	1.0	1.0
	3%	0.0	0.8	0.8
Carbon black plants	7%	0.01	0.2	0.2
	3%	0.005	0.1	0.1
Phosphate rock processing plants	7%	0.0	0.1	0.2
	3%	0.0	0.2	0.2
Secondary metal production facilities	7%	0.02	0.04	0.1
	3%	0.0	0.0	0.0
Total	7%	$151.43	$1,193.24	$2,237.24
	3%	$272.34	$1,157.09	$1,770.21

discount rate leads to more sources having available controls under that scenario. At scenario 2, the annualized costs and reductions are relatively close because the controls available to sources are about the same. At scenario 3, the available controls are about identical regardless of the discount rate, but the costs are lower for the 3 percent discount rate because of the lower capital costs overall.

Tables 8-4 through 8-6 summarize the results for the $2,000/ton and $3,000/ton non-EGU scenarios in the same way as for Scenarios 1 through 3. Table 8-4 summarizes the SO_2 emission reductions from applying these two BART non-EGU source categories using a discount rate of 7 percent and also showing results using an discount rate of 3 percent. In

Table 8-4. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons) $2,000/ton Scenario	$3,000/ton Scenario
Industrial boilers	420,782	7%	87,009	124,592
	420,782	3%	120,095	148,962
Petroleum refineries	199,483	7%	23,173	23,173
	199,483	3%	25,103	33,304
Kraft pulp mills	119,818	7%	0	0
	119,818	3%	0	3,196
Portland cement plants	116,835	7%	2,350	2,350
	116,835	3%	2,743	13,383
Hydrofluoric, sulfuric, and nitric acid plants	96,741	7%	35,358	36,753
	96,741	3%	36,753	36,753
Chemical process plants	47,700	7%	2,376	2,376
	47,700	3%	2,376	2,376
Iron and steel mills	23,541	7%	2,914	2,914
	23,541	3%	2,914	2,914
Coke oven batteries	9,815	7%	4,088	4,088
	9,815	3%	4,088	4,088
Sulfur recovery plants	59,766	7%	13,697	13,697
	59,766	3%	14,311	14,311
Primary aluminum ore reduction plants	47,552	7%	1,630	1,630
	47,552	3%	1,630	3,260
Lime kilns	9,373	7%	0	0
	9,373	3%	0	0

(continued)

Table 8-4. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons) $2,000/ton Scenario	$3,000/ton Scenario
Glass fiber processing plants	2,170	7%	0	0
	2,170	3%	0	0
Municipal incinerators	284	7%	0	0
	284	3%	0	0
Coal cleaning plants	1,530	7%	0	0
	1,530	3%	0	0
Carbon black plants	41,853	7%	0	0
	41,853	3%	0	0
Phosphate rock processing plants	21	7%	0	0
	21	3%	0	0
Secondary metal production facilities	9,988	7%	0	0
	9,988	3%	0	0
Total	1,208,088	7%	172,595	211,573
	1,208,088	3%	210,013	262,547

total, the scenarios applied in this analysis lead to nationwide SO_2 emission reductions ranging from 172,595 tons to 211,573 tons with costs at a 7 percent discount rate. These estimates represent a reduction of 14 to 18 percent from the 2015 baseline. These scenarios lead to SO_2 emission reductions ranging from 210,013 to 262,547 tons with costs at a 3 percent rate. These estimates represent a reduction of 17 to 22 percent from the 2015 baseline.

Table 8-5 summarizes the NO_x emission reductions for these two non-EGU scenarios. The nationwide NO_x emission reductions from applying these three scenarios range from 242,355 tons to 291,740 tons with costs at a 7 percent discount rate. These represent a reduction of 36 to 43 percent from the 2015 baseline. These scenarios lead to NO_x emission reductions ranging from 280,163 to 313,382 tons with costs at a 3 percent rate. These represent a reduction of 41 to 46 percent from the 2015 baseline.

Table 8-5. NO_x Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios: $2,000/ton Scenario	$3,000/ton Scenario
Industrial boilers	217,063	7%	97,074	125,575
	217,063	3%	120,151	128,640
Petroleum refineries	86,566	7%	23,173	23,173
	86,566	3%	23,173	26,685
Kraft pulp mills	103,614	7%	50,221	60,985
	103,614	3%	56,466	64,521
Portland cement plants	120,567	7%	26,659	26,659
	120,567	3%	26,659	26,659
Hydrofluoric, sulfuric, and nitric acid plants	17,059	7%	11,283	11,283
	17,059	3%	11,283	11,283
Chemical process plants	72,577	7%	25,922	26,753
	72,577	3%	27,568	31,567
Iron and steel mills	20,963	7%	2,034	3,259
	20,963	3%	2,038	7,198
Coke oven batteries	10,389	7%	0	5,768
	10,389	3%	5,768	5,768
Sulfur recovery plants	651	7%	0	0
	651	3%	0	0
Primary aluminum ore reduction plants	1,676	7%	70	253
	1,676	3%	335	335
Lime kilns	12,849	7%	4,471	4,471
	12,849	3%	4,471	7,153

(continued)

Table 8-5. NO_x Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios: $2,000/ton Scenario	Scenarios: $3,000/ton Scenario
Glass fiber processing plants	6,677	7%	568	2,116
	6,677	3%	851	2,116
Municipal incinerators	1,656	7%	744	744
	1,656	3%	744	744
Coal cleaning plants	1,110	7%	0	511
	1,110	3%	511	511
Carbon black plants	4,645	7%	111	120
	4,645	3%	111	120
Phosphate rock processing plants	719	7%	0	45
	719	3%	0	48
Secondary metal production facilities	1,377	7%	25	25
	1,377	3%	34	34
Total	681,765	7%	242,355	291,740
	681,765	3%	280,163	313,382

Table 8-6 summarizes the annualized costs associated with these two non-EGU scenarios. In total, the two scenarios applied in this analysis have annualized costs of $512.36 million to $706.26 million (1999$) with costs at a 7 percent discount rate and $507.23 million to $691.73 million (1999$) with costs at a 3 percent discount rate.

Given the highly capital-intensive nature of the control measures included in these analyses, it is not unreasonable that a lower discount rate would lead to more application of these measures to reduce SO_2 and NO_x and vice versa. More sources would be controlled that may not be able to control if they face relatively high interest rates for capital outlays in pollution control equipment. At the $2,000/ton scenario, the emission reductions are higher with a 3 percent discount rate than a 7 percent discount rate because the lower discount rate

Table 8-6. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$)

BART Source Category	Discount Rate	Scenarios: $2,000/ton Scenario	$3,000/ton Scenario
Industrial boilers	7%	241.5	412.1
	3%	255.0	337.4
Petroleum refineries	7%	71.1	71.1
	3%	71.1	81.2
Kraft pulp mills	7%	75.1	75.1
	3%	59.2	68.5
Portland cement plants	7%	29.6	29.6
	3%	28.7	56.6
Hydrofluoric, sulfuric, and nitric acid plants	7%	20.4	21.4
	3%	21.4	21.4
Chemical process plants	7%	40.5	40.5
	3%	30.4	40.1
Iron and Steel mills	7%	7.9	11.0
	3%	5.7	22.7
Coke oven batteries	7%	6.2	18.7
	3%	14.9	14.9
Sulfur Recovery plants	7%	11.7	12.1
	3%	12.1	12.1
Primary aluminum ore reduction plants	7%	1.7	2.2
	3%	1.0	5.0
Lime kilns	7%	5.0	5.0
	3%	4.3	25.4

(continued)

Table 8-6. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$) (continued)

BART Source Category	Discount Rate	Scenarios: $2,000/ton Scenario	Scenarios: $3,000/ton Scenario
Glass fiber processing plants	7%	0.5	5.3
	3%	1.7	4.7
Municipal incinerators	7%	1.1	1.1
	3%	0.9	0.9
Coal cleaning plants	7%	0.0	1.0
	3%	0.8	0.8
Carbon black plants	7%	0.01	0.01
	3%	0.005	0.01
Phosphate rock processing plants	7%	0.01	0.01
	3%	0.01	0.01
Secondary metal production facilities	7%	0.04	0.04
	3%	0.01	0.01
Total	7%	$512.36	$706.26
	3%	$507.23	$691.73

leads to more sources having available controls under that scenario and the costs are fairly close. At $3,000/ton scenario, the annualized costs and reductions are relatively closer. More details on these results can be found in Appendix G.

8.3 Costs and Analysis Approach

The potential costs of complying with the BART rule estimated in this chapter are those from installation, operation, and maintenance of control devices that may be applied in response to the provisions of SIP) that may require controls of these non-EGU sources. In addition to these analyses, results from analyses in which important components of the costs such as discount rates, labor rates, and energy rates are varied to determine the sensitivity of the costs to such variation. We present such results in Appendix B. Costs from monitoring, record keeping, and reporting are not included in this cost analysis because these costs are accounted for in the Regional Haze ICR.

Two types of costs will be incurred in association with the addition of control technologies: a one-time capital cost for new equipment installation and increased annual operating and maintenance costs. In general, economies of scale exist for pollution control technologies for both capital costs and operating and maintenance costs. Thus, the size of the unit to which controls are applied will determine, in part, the cost of implementing the pollution control(s).

For each affected source category, EPA's estimates of emissions reductions and costs reflect the application of controls within AirControlNET, the Agency's tool for estimating impacts from control strategies applied to non-EGU criteria pollutant sources. AirControlNET can estimate costs and emission reductions from control strategies for various average cost-effectiveness levels and for varying geographic scales (nationally, regionally, and locally).[2] For this analysis, we applied in AirControlNET control measures up to the given average annualized cost per ton cutoff for SO_2 and NO_x to the BART-eligible units within the non-EGU dataset described in Chapter 3. These analyses are calculated for control measures applied to the 2015 emissions inventory, which is a product of growing the emissions from the non-EGU dataset, a database with 2001 emissions in it. The procedure for growing the emissions in that database to 2015 is also described in Chapter 3.

Costs presented in this chapter are estimated at a 3 percent and 7 percent discount rate for purposes of annualizing capital costs consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003). Equipment lives and control efficiencies for each control technology are taken from the AirControlNET control measures documentation report. Annual costs are estimated in 1999 dollars. All costs are converted from the original source year to 1999 dollars using the gross domestic product (GDP) price deflator.

[2]For more information on the emissions and control measures within AirControlNET, go to www.epa.gov/ttn/ecas/AirControlNET.htm. Documentation for emissions data and control measures can be found at this Web site.

8.4 Types of Emissions Control Technologies Employed in These Analyses

A number of technologies are commonly employed to reduce SO_2 and NO_x emissions from the non-EGU source categories. This section of the chapter covers many of the technologies employed in reducing these pollutants.

8.4.1 SO_2 Emissions Control Technologies

This section describes available technologies for controlling emissions of SO_2 for industrial, commercial, and institutional (ICI) boilers[3] and other non-EGU source categories. In general, FGD scrubbers are applied most commonly as the control technology for industrial boilers and many other non-EGU sources because of their possible application to most any industrial boiler and other combustion source application. Other issues involved in choosing a control technology include ease of retrofit and reduction performance. While all controls presented in this analysis are considered generally technically feasible for each class of sources, source-specific cases may exist where a control technology is in fact not technically feasible. In their response to the BART rule, States should consider case-specific feasibility when establishing control requirements.

8.4.1.1 SO_2 Control Technology for Non-EGU Sources

For industrial boilers, FGD scrubbers are the only technology available in our data. This is not to say that other technologies are not available or that a technique such as switching from high-sulfur coal (e.g., 3 percent sulfur content by weight) to lower-sulfur coal (e.g., 1 percent sulfur content by weight) could not be employed to achieve SO_2 reductions, but data for such technologies or technique were not available for this analysis. FGD scrubbers are also used on units at petroleum refineries, kraft pulp mills, and Portland cement kilns. For other BART source categories, other types of control technologies were available that are more specific to the sources controlled. Table 8-7 lists these technologies. For more information on these technologies, please refer to the AirControlNET 4.0 control measures documentation report.

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[3] The terms “ICI boiler” and “industrial boiler” are used interchangeably in this RIA.

Table 8-7. Available SO_2 Control Technologies for Industrial Boilers and Other Non-EGU Sources

Source Type/Fuel Type	Available Control Technology
ICI boilers—all fuel types, kraft pulp mills, Portland cement plants (all fuel types)	FGD scrubbers
Hydrofluoric, sulfuric, and nitric acid	Increase percentage sulfur conversion to meet sulfuric acid NSPS (99.7% reduction)
Sulfur recovery plants	Sulfur recovery and/or tail gas treatment
Coke oven batteries	Vacuum carbonate + sulfur recovery plant

Source: AirControlNET control measures documentation report.

8.4.2 NO_x Emissions Control Technologies

This section describes available technologies for controlling emissions of NO_x for ICI boilers and other non-EGU sources. In general, low-NO_x burners (LNB) are often applied as a control technology for industrial boilers and many other non-EGU sources because of their possible application to almost any industrial boiler and other combustion source application. Other issues involved in choosing a control technology include ease of retrofit and reduction performance. While all controls presented in this analysis are considered generally technically feasible for each class of sources, source-specific cases may exist where a control technology is in fact not technically feasible. In their response to the BART rule, States should consider case-specific feasibility when establishing control requirements.

8.4.2.1 NO_x Control Technology for Non-EGU Sources

Several types of control technologies are considered for industrial boilers: SCR, selective noncatalytic reduction (SNCR), natural gas reburn (NGR), coal reburn, and low-NO_x burners. As stated above, the control technology chosen most often was LNB because of its breadth of application. In some cases, LNB accompanied by flue gas reburning (FGR) is applicable, such as when fuel-borne NO_x emissions are expected to be of greater importance than thermal NO_x emissions. When circumstances suggest that combustion controls do not make sense as a control technology (e.g., sintering processes, coke oven batteries, sulfur recovery plants), SNCR or SCR may be an appropriate choice.

Table 8-8 lists the control technologies available for industrial boilers and other non-EGU sources by type of fuel. For more information on these technologies, please refer to the AirControlNET 4.0 control measures documentation report.

Table 8-8. Available NO_x Control Technologies for Industrial Boilers

Source Type/Fuel Type	Available Control Technology
ICI boilers—coal/wall	SNCR, LNB, SCR
ICI boilers—coal/FBC (fluidized bed combustor)	SNCR—urea based
ICI boilers—coal/stoker	SNCR—urea based
ICI boilers—coal/cyclone	SNCR, Coal Reburn, NGR, SCR
ICI boilers—residual oil	LNB, SNCR, LNB + FGR, SCR
ICI boilers—distillate oil	LNB, SNCR, LNB + FGR, SCR
ICI boilers—natural gas	LNB, SNCR, LNB + FGR, OT + WI, SCR
ICI boilers—process gas	LNB, LNB + FGR, OT + WI, SCR
ICI boilers—coke	SNCR, LNB, SCR
ICI boilers—LPG (liquid petroleum gas)	LNB, SNCR, LNB + FGR, SCR

Source: AirControlNET control measures documentation report.

8.4.2.2 NO_x Control Technology for Other Non-EGU BART Source Categories

Other non-EGU source categories covered in the analysis include petroleum refineries, kraft pulp mills, and cement kilns. NO_x control technologies available for petroleum refineries, particularly process heaters at these plants, include LNB, SNCR, FGR, and SCR along with combinations of these technologies. NO_x control technologies available for kraft pulp mills include those available to industrial boilers, namely LNB, SCR, SNCR, along with water injection (WI). NO_x control technologies available for cement kilns include those available to industrial boilers, namely LNB, SCR, and SNCR. In addition, mid-kiln firing (MKF) and ammonia-based SNCR can be used on cement kilns where appropriate. Table 8-9 lists the control technologies available for these categories. For more information on these technologies, please refer to the AirControlNET 4.0 control measures documentation report.

Table 8-9. Available NO_x Control Technologies for Other Non-EGU Source Categories Other than Industrial Boilers

Source Type/Fuel Type	Available Control Technology
Petroleum refineries (process heaters—process gas, distillate oil)	LNB + FGR, SNCR, LNB + SNCR, SCR, LNB + SCR
Kraft pulp mills	LNB, SNCR, SCR, LNB + SNCR, SCR + WI
Cement manufacturing—dry	MKF, LNB, SNCR—urea based, SNCR—ammonia based, SCR
Cement manufacturing—wet	MKF, LNB, SCR, biosolid injection
In-process; bituminous coal; cement kilns	SNCR—urea based
Chemical process plants	LNB, SNCR, SCR, SCR + WI
Lime kilns	SCR
Iron and steel mills	LNB, SNCR, LNB + SNCR, LNB + FGR, SCR

Source: AirControlNET control measures documentation report.

8.5 Listing of Affected Source Categories and Results for Each

We present below results for each BART source category affected in the analyses. Results presented here reflect the use of 7 percent and 3 percent discount rates as part of the control strategy analysis for each scenario. There are no impacts for 8 of the 25 non-EGU source categories because there are no control measures available to reduce SO_2 and NO_x from these categories within AirControlNET. For seven source categories only NO_x reductions take place in these analyses because there are no control measures available within AirControlNET or no controls available at $10,000/ton or below. Finally, there are 10 source categories for which both SO_2 and NO_x reductions take place in these analyses. The first 10 source categories for which impacts are presented are those for which both SO_2 and NO_x reductions take place in these analyses. These BART source categories are

- industrial boilers (250 mmBTU/hr heat input capacity and greater);
- petroleum refineries;
- kraft pulp mills;
- Portland cement plants;

- hydrofluoric, sulfuric, and nitric acid;
- chemical process plants;
- iron and steel mills;
- coke oven batteries;
- sulfur recovery plants; and
- primary aluminum ore reductions.

For seven source categories, only NO_x reductions take place:

- lime kilns,
- glass fiber processing plants,
- municipal incinerators (250 tons refuse burn capacity or greater),
- coal cleaning plants (thermal dryers),
- carbon black plants (furnace process),
- phosphate rock processing plants, and
- secondary metal production facilities.

Finally, for eight source categories there are no impacts estimated because there are no BART-eligible units in the non-EGU dataset or no controls available to reduce emissions from BART-eligible units:

- primary lead smelters,
- primary copper smelters,
- primary zinc smelters,
- fuel conversion plants,
- sintering plants,
- charcoal production facilities,
- taconite ore processing plants, and
- petroleum storage and transfer facilities.

8.5.1 Results for Industrial Boilers

Table 8-10 shows the SO_2 emissions reductions achieved in the analyses for each illustrative scenario. Besides the standard BART eligibility criteria mentioned in Chapter 3, boilers that are BART eligible are those with heat input design capacities of 250 mmBtu/hr or greater and are fossil fueled. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 8 to 48 percent given a 7 percent discount rate for the costs and from 16 to 49 percent for costs at a 3 percent discount rate.

Table 8-10. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU Industrial Boilers[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	420,782	7%	388,569	32,213
	420,782	3%	354,999	65,783
Scenario 2	420,782	7%	269,395	151,387
	420,782	3%	256,344	164,438
Scenario 3	420,782	7%	220,474	200,308
	420,782	3%	216,565	204,217

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-11 presents the NO_x baseline emissions and reductions for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline, ranging from 32 percent to 60 percent for costs at a 7 percent discount rate and from 52 to 60 percent for costs at a 3 percent discount rate.

Table 8-12 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $26.0 million to $610.3 million with costs at a 7 percent discount rate, and from $47.8 million to $504.6 million with costs at a 3 percent discount rate. The accompanying average annualized cost-effectiveness results range from $807 to $3,047 per ton with costs at a 7 percent rate and from $727 to $2,471 per ton with costs at a 3 percent rate. In addition, the marginal costs range from $2,250 to $6,463 per ton with costs at a 7 percent discount rate and from $2,202 to $6,023 per ton with costs at a 3 percent discount rate.

Table 8-11. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU Industrial Boilers[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	217,063	7%	149,738	67,325
	217,063	3%	105,124	111,939
Scenario 2	217,063	7%	86,607	130,456
	217,063	3%	86,639	130,424
Scenario 3	217,063	7%	86,541	130,522
	217,063	3%	86,558	130,505

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-12. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$26.0	$807	—
	3%	$47.8	$727	—
Scenario 2	7%	$294.1	$1,943	$2,250
	3%	$265.0	$1,612	$2,202
Scenario 3	7%	$610.3	$3,047	$6,463
	3%	$504.6	$2,471	$6,023

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to more coal-fired units with lower sulfur contents and to oil-fired units that have lower sulfur contents than coal-fired units.

Table 8-13 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $48.6 million to $235.1 million with costs at a 7 percent rate and from $87.2 million to $138.7 million with costs at a 3 percent rate. The accompanying annualized average cost-effectiveness results range from $722 to $1,801 per ton with costs at a 7 percent rate and from $779 to $1,063 per ton with costs at a 3 percent rate. In addition, the marginal costs range from $2,929 to $24,242 per ton with costs at a 7 percent rate and from $2,684 to $22,840 per ton with costs at a 3 percent rate.

Table 8-13. 2015 Cost and Cost-Effectiveness Results for NO_x Control at BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$48.6	$722	—
	3%	$87.2	$779	—
Scenario 2	7%	$233.5	$1,790	$2,929
	3%	$136.8	$1,049	$2,684
Scenario 3	7%	$235.1	$1,801	$24,242
	3%	$138.7	$1,063	$22,840

The average and marginal costs increase as the scenarios become more stringent as a result of additional application of SCR. SCR is the most expensive NO_x control device available to industrial boilers in our analysis, though they also have a high control level (80 percent).

Table 8-14 shows the total annualized costs for each scenario for controlling both SO_2 and NO_x.

8.5.2 Results for Petroleum Refineries

Table 8-15 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 1 percent to 28 percent for costs estimated at a 7 percent discount rate and from 9 percent to 29 percent for costs estimated at a 3 percent discount rate.

Table 8-14. 2015 Cost Results for SO_2 and NO_x Control at BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$74.6
	3%	$135.0
Scenario 2	7%	$527.6
	3%	$401.8
Scenario 3	7%	$845.4
	3%	$643.3

Table 8-15. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Petroleum Refineries[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	199,483	7%	197,386	2,097
	199,483	3%	182,450	17,033
Scenario 2	199,483	7%	168,164	31,319
	199,483	3%	157,572	41,911
Scenario 3	199,483	7%	143,021	56,462
	199,483	3%	140,958	58,525

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-16 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 5 to 59 percent for costs estimated at a 7 percent discount rate and from 6 to 60 percent for costs estimated at a 3 percent discount rate.

Table 8-16. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Petroleum Refineries[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	86,566	7%	82,531	4,035
		3%	81,987	4,579
Scenario 2	86,566	7%	39,010	47,556
		3%	35,307	51,259
Scenario 3	86,566	7%	35,250	51,316
		3%	33,561	53,005

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-17 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $1.9 million to $223.5 million with costs at a 7 percent discount rate and from $12.5 million to $167.3 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $906 to $3,958 per ton with costs at a 7 percent discount rate and from $736 to $2,858 per ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $1,783 to $6,741 per ton with costs at a 7 percent discount rate and from $2,417 to $5,692 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to units such as fluid catalytic cracking units (FCCUs) with lower sulfur contents. As sulfur content of the fuel for a unit decreases, the cost per ton of control increases and vice versa.

Table 8-18 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $2.3 million to $205.1 million with costs at a 7 percent discount rate and from $2.7 million to $227.6 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $570 to $3,997 per ton with costs at a 7 percent discount rate and from $595 to $4,294 per

Table 8-17. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$1.9	$906	—
	3%	$12.5	$736	—
Scenario 2	7%	$54.0	$1,724	$1,783
	3%	$72.7	$1,734	$2,417
Scenario 3	7%	$223.5	$3,958	$6,741
	3%	$167.3	$2,858	$5,692

Table 8-18. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$2.3	$570	—
	3%	$2.7	$595	—
Scenario 2	7%	$126.2	$2,654	$2,917
	3%	$142.1	$2,772	$2,986
Scenario 3	7%	$205.1	$3,997	$20,984
	3%	$227.6	$4,294	$48,969

ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $2,917 to $20,984 per ton with costs at a 7 percent discount rate and from $2,986 to $48,969 per ton with costs at a 3 percent discount rate.

The average and marginal costs rise as a result of additional process heaters having to apply LNB + SNCR. In most cases, the average cost per ton of control is between $4,000 and $5,000 per ton.

Table 8-19 shows the total annualized costs for controlling both SO_2 and NO_x.

Table 8-19. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$4.2
	3%	$15.3
Scenario 2	7%	$180.2
	3%	$214.8
Scenario 3	7%	$428.6
	3%	$394.8

8.5.3 Kraft Pulp Mills

Table 8-20 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 24 percent for costs at a 7 percent discount rate and from 0 to 12 percent for costs at a 3 percent discount rate.

Table 8-21 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 34 percent to 63 percent for costs at a 7 percent discount rate and from 52 to 63 percent for costs at a 3 percent discount rate.

Table 8-22 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $0 to $161.5 million with costs at a 7 percent discount rate and from $0 to $69.0 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 to $5,691 per ton with costs at a 7 percent discount rate and from $0 to $4,720 per ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $3,098 to $7,287 per ton with costs at a 7 percent discount rate and from $2,189 to $5,432 per ton with costs at a 3 percent discount rate.

Table 8-20. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Kraft Pulp Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	119,818	7%	119,818	0
	119,818	3%	119,818	0
Scenario 2	119,818	7%	109,005	10,814
	119,818	3%	116,820	3,196
Scenario 3	119,818	7%	91,488	28,330
	119,818	3%	105,208	14,610

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-21. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Kraft Pulp Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	103,614	7%	68,365	35,249
	103,614	3%	49,885	53,729
Scenario 2	103,614	7%	42,196	61,418
	103,614	3%	37,822	65,792
Scenario 3	103,614	7%	37,838	65,776
	103,614	3%	37,827	65,797

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-22. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discoun t Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$33.5	$3,098	$3,098
	3%	$7.0	$2,189	$2,189
Scenario 3	7%	$161.5	$5,691	$7,287
	3%	$69.0	$4,720	$5,432

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to units for which the application is more expensive ($6,000 to $10,000 per ton).

Table 8-23 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $20.7 million to $151.8 million with costs at a 7 percent discount rate and from $45.6 million to $99.8 million with costs at a 3 percent rate. The accompanying annualized average cost-effectiveness results range from $587 to $2,308 per ton with costs at a 7 percent discount rate and from $849 to $1,512 per ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $3,344 to $10,005 per ton with costs at a 7 percent discount rate and from $4,452 to $35,800 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect greater applications of SCR as the cost-per-ton cap rises, particularly for sulfite pulping recovery furnaces.

Table 8-24 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table 8-23. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
Scenario 1	7%	$20.7	$587	—
	3%	$45.6	$849	—
Scenario 2	7%	$108.2	$1,762	$3,344
	3%	$99.3	$1,510	$4,452
Scenario 3	7%	$151.8	$2,308	$10,005
	3%	$99.5	$1,512	$35,800

Table 8-24. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$20.7
	3%	$45.6
Scenario 2	7%	$141.7
	3%	$106.3
Scenario 3	7%	$313.3
	3%	$168.5

8.5.4 Results for Portland Cement Plants

Table 8-25 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 percent to 23 percent for costs at a 7 percent discount rate and from 0 to 26 percent for costs at a 3 percent discount rate.

Table 8-25. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Portland Cement Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	116,835	7%	116,835	0
	116,835	3%	116,835	0
Scenario 2	116,835	7%	103,452	13,383
	116,835	3%	98,509	18,326
Scenario 3	116,835	7%	90,119	26,716
	116,835	3%	86,145	30,690

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-26 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 16 percent to 60 percent for costs at a 7 percent discount rate and from 26 to 60 percent for costs at a 3 percent discount rate.

Table 8-26. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Portland Cement Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	120,567	7%	101,289	19,276
	120,567	3%	89,664	30,903
Scenario 2	120,567	7%	65,966	54,601
	120,567	3%	48,646	71,921
Scenario 3	120,567	7%	48,646	71,921
	120,567	3%	48,646	71,921

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-27 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $0 to $134.4 million with costs at a 7 percent discount rate and from $0 to $126.8 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 to $5,031 per ton with costs at a 7 percent discount rate and from $0 to $4,131 per ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $3,250 to $6,818 per ton with costs at a 7 percent discount rate and from $2,710 to $6,816 per ton with costs at a 3 percent discount rate.

Table 8-27. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$43.5	$3,250	$3,250
	3%	$49.7	$2,710	$2,710
Scenario 3	7%	$134.4	$5,031	$6,818
	3%	$126.8	$4,131	$6,816

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to more units with lower sulfur content fuels.

Table 8-28 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $2.9 million to $275.1 million with costs at a 7 percent discount rate and from $20.8 million to $219.3 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $150 to $3,825 per ton with costs at a 7 percent discount rate and from $674 to $3,050 per ton with costs at a 3 percent discount rate. In addition, the marginal costs range from $3,632 to $7,731 per ton with costs at a 7 percent discount rate and are $4,839 per ton with costs at a

Table 8-28. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
Scenario 1	7%	$2.9	$150	—
	3%	$20.8	$674	—
Scenario 2	7%	$131.2	$2,403	$3,632
	3%	$219.3	$3,050	$4,839
Scenario 3	7%	$275.1	$3,825	$7,731
	3%	$219.3	$3,050	N/A

3 percent discount rate between the $1,000/ton and the $4,000/ton scenarios. There is no marginal costs between the $4,000/ton and $10,000/ton scenarios with costs at the 3 percent discount rate because there is no difference in the impacts of the scenarios.

The average and marginal costs of control increase as more SCR applications take place as the cost-per-ton cap rises. These applications take the place of less expensive but less effective controls such as mid-kiln firing.

Table 8-29 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table 8-29. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$2.9
	3%	$20.8
Scenario 2	7%	$174.8
	3%	$269.0
Scenario 3	7%	$409.5
	3%	$346.1

8.5.5 Results for Hydrofluoric, Sulfuric, and Nitric Acid Plants

Table 8-30 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 35 to 38 percent for costs at a 7 percent discount rate and the same for costs at a 3 percent discount rate.

Table 8-30. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	96,741	7%	62,601	34,140
	96,741	3%	62,601	34,140
Scenario 2	96,741	7%	60,188	36,753
	96,741	3%	60,188	36,753
Scenario 3	96,741	7%	60,188	36,753
	96,741	3%	60,188	36,753

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-31 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of about 66 percent. The degree of impact varies little between scenarios and the discount rate of the costs.

Table 8-32 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $9.8 million to $15.2 million with costs at a 7 percent discount rate and from $9.1 million to $14.1 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $287 to $413 per ton with costs at a 7 percent discount rate and from $268 to $385 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $2,067 per ton with costs at a 7 percent discount rate and $1,914 per ton with costs at a 3 percent discount rate. In this case, there are no controls between $4,000/ton and $10,000/ton; thus, there are no marginal costs between these two scenarios.

Table 8-31. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	17,059	7%	5,783	11,276
	17,059	3%	5,783	11,276
Scenario 2	17,059	7%	5,776	11,283
	17,059	3%	5,776	11,283
Scenario 3	17,059	7%	5,776	11,283
	17,059	3%	5,776	11,283

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-32. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$9.8	$287	—
	3%	$9.1	$268	—
Scenario 2	7%	$15.2	$413	$2,067
	3%	$14.1	$385	$1,914
Scenario 3	7%	$15.2	$413	N/A
	3%	$14.1	$385	N/A

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce SO_2 emissions from these sources—increase sulfur conversion to meet the sulfuric acid NSPS (99.7 percent control).

Table 8-33 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $8.19 million to $8.21 million with costs at a 7 percent discount rate and from $7.29 million to $7.30 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $726 to $728 per ton with costs at a 7 percent discount rate and from $646 to $647 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $4,428 per ton with costs at a 7 percent discount rate and $2,157 per ton with costs at a 3 percent discount rate. In this case, there are no controls between $4,000/ton and $10,000/ton; thus, there are no marginal costs between these two scenarios.

Table 8-33. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Illustrative Regulatory Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$8.2	$726	—
	3%	$7.3	$646	—
Scenario 2	7%	$8.2	$728	$4,428
	3%	$7.3	$647	$2,157
Scenario 3	7%	$8.2	$728	N/A
	3%	$7.3	$647	N/A

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce NO_x emissions from these sources—SNCR applied to nitric acid manufacturing sources.

Table 8-34 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table 8-34. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$18.0
	3%	$16.4
Scenario 2	7%	$23.4
	3%	$21.4
Scenario 3	7%	$23.4
	3%	$21.4

8.5.6 Results for Chemical Process Plants

Table 8-35 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 percent to 7 percent for costs at either a 7 or a 3 percent discount rate.

Table 8-35. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Chemical Process Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	47,700	7%	47,700	0
	47,700	3%	47,700	0
Scenario 2	47,700	7%	45,324	2,376
	47,700	3%	45,324	2,376
Scenario 3	47,700	7%	44,129	3,571
	47,700	3%	44,129	3,571

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-36 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 33 percent to 48 percent for costs at a 7 percent discount rate and from 37 to 48 percent for costs at a 3 percent discount rate.

Table 8-36. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Chemical Process Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	72,577	7%	48,607	23,970
	72,577	3%	45,435	27,142
Scenario 2	72,577	7%	37,941	34,636
	72,577	3%	37,776	34,801
Scenario 3	72,577	7%	37,776	34,801
	72,577	3%	37,385	35,192

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-37 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from \$0 to \$13.7 million with costs at a 7 percent discount rate and from \$0 to \$10.2 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from \$0 to \$3,836 per ton with costs at a 7 percent discount rate and from \$0 to \$2,850 per ton with costs at a 3 percent discount rate. The marginal costs range from \$1,052 to \$9,372 per ton with costs at a 7 percent discount rate and from \$1,013 to \$6,527 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect a major difference in the impacts between the two available control techniques: increase sulfur percentage conversion to meet the sulfuric acid NSPS (99.7 percent control) and FGD scrubbers.

Table 8-37. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$2.5	$1,052	$1,052
	3%	$2.4	$1,013	$1,013
Scenario 3	7%	$13.7	$3,836	$9,372
	3%	$10.2	$2,850	$6,527

Table 8-38 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $14.4 million to $74.1 million with costs at a 7 percent discount rate and from $21.1 million to $77.1 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $601 to $2,129 per ton with costs at a 7 percent discount rate and from $776 to $2,191 per ton with costs at a 3 percent discount rate. In addition, the marginal costs of the scenarios range from $5,030 to $35,758 per ton with costs at a 7 percent discount rate and from $4,348 to $58,082 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect the application of many different types of NO_x controls. The reason for the large increase in marginal costs associated with the $10,000/ton scenario is the applications of LNB + SNCR or SCR that would take place at units within these plants according to our analysis.

Table 8-39 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table 8-38. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$14.4	$601	—
	3%	$21.1	$776	—
Scenario 2	7%	$68.2	$1,969	$5,030
	3%	$54.4	$1,563	$4,348
Scenario 3	7%	$74.1	$2,129	$35,758
	3%	$77.1	$2,191	$58,082

Table 8-39. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$14.4
	3%	$21.1
Scenario 2	7%	$70.8
	3%	$56.8
Scenario 3	7%	$87.8
	3%	$87.3

8.5.7 Results for Iron and Steel Mills

Table 8-40 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 12 percent for costs at either a 7 or 3 percent discount rate.

Table 8-40. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Iron and Steel Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	23,541	7%	23,541	0
	23,541	3%	23,541	0
Scenario 2	23,541	7%	20,627	2,914
	23,541	3%	20,627	2,914
Scenario 3	23,541	7%	20,627	2,914
	23,541	3%	20,627	2,914

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-41 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 5 to 41 percent at costs of either a 7 or 3 percent discount rate.

Table 8-41. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Iron and Steel Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	20,963	7%	19,927	1,036
	20,963	3%	19,927	1,036
Scenario 2	20,963	7%	13,966	6,997
	20,963	3%	12,463	8,500
Scenario 3	20,963	7%	12,456	8,507
	20,963	3%	12,290	8,673

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-42 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $0 to $5.3 million with costs at a 7 percent discount rate and from $0 to $3.4 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 to $1,819 per ton with costs at a 7 percent discount rate and from $0 to $1,165 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $1,819 per ton with costs at a 7 percent discount rate and $1,165 per ton with costs at a 3 percent discount rate. In this case, there are no controls between $4,000/ton and $10,000/ton; thus, there are no marginal costs between these two scenarios.

Table 8-42. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$5.3	$1,819	$1,819
	3%	$3.4	$1,165	$1,165
Scenario 3	7%	$5.3	$1,819	N/A
	3%	$3.4	$1,165	N/A

The costs and emission reductions are flat between the scenarios because the two controls available both have similar average cost-per-ton estimates below $4,000: sulfuric acid plant and increase sulfur conversion to meet the sulfuric acid NSPS (99.7 percent control).

Table 8-43 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $0.6 million to $27.9 million with costs at a 7 percent discount rate and from $0.4 million to $29.0 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $579 to $3,280 per ton with costs at a 7 percent discount rate and from $431 to $3,343 per

Table 8-43. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.6	$579	—
	3%	$0.4	$431	—
Scenario 2	7%	$18.2	$2,601	$2,953
	3%	$19.3	$2,271	$2,532
Scenario 3	7%	$27.9	$3,280	$6,424
	3%	$29.0	$3,343	$56,052

ton with costs at a 3 percent discount rate. The marginal costs range from $2,953 to $6,424 per ton with costs at a 7 percent discount rate and from $2,532 to $56,052 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect a rise in the costs of control due to additional applications of LNB + either SNCR or SCR.

Table 8-44 shows the total annualized costs for controlling both SO_2 and NO_x.

Table 8-44. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$0.6
	3%	$0.4
Scenario 2	7%	$23.5
	3%	$22.7
Scenario 3	7%	$33.2
	3%	$32.4

8.5.8 Results for Coke Oven Batteries

Table 8-45 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 62 percent for costs at a 7 percent discount rate and from 0 to 57 percent for costs at a 3 percent discount rate.

Table 8-45. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	9,815	7%	9,815	0
	9,815	3%	9,815	0
Scenario 2	9,815	7%	5,727	4,088
	9,815	3%	6,091	3,724
Scenario 3	9,815	7%	3,708	6,107
	9,815	3%	4,251	5,564

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-46 shows the emissions reductions achieved in the analyses for each scenario for NO_x control. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 56 percent for costs at a 7 or 3 percent discount rate.

Table 8-47 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $0 to $21.3 million with costs at a 7 percent discount rate and from $0 to $14.1 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 to $3,488 per ton with costs at a 7 percent discount rate and from $0 to $2,529 per ton with costs at a 3 percent discount rate. The marginal costs range from $1,517 to $7,479 per ton with costs at a 7 percent discount rate and from $1,074 to $5,489 per ton with costs at a 3 percent discount rate.

Table 8-46. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Coke Oven Batteries[a]

Scenarios	2015 Baseline Emissions	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	10,389	10,389	0
	10,389	10,389	0
Scenario 2	10,389	4,621	5,768
	10,389	4,621	5,768
Scenario 3	10,389	4,621	5,768
	10,389	4,621	5,768

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-47. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1990$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$6.2	$1,517	$1,517
	3%	$4.0	$1,074	$1,074
Scenario 3	7%	$21.3	$3,488	$7,479
	3%	$14.1	$2,529	$5,489

The costs and emission reductions reflect application of only one control—vacuum carbonate plus a sulfur recovery plant but also differing SO_2 emissions levels at the affected coke oven batteries.

Table 8-48 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from \$0 to \$12.5 million with costs at a 7 percent discount rate and from \$0 to \$10.9 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from \$0 to \$2,167 per ton with costs at a 7 percent discount rate and from \$0 to \$1,898 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are \$2,167 per ton with costs at a 7 percent discount rate and \$1,898 per ton at a 3 percent discount rate. In this case, there are no controls available between \$4,000/ton and \$10,000/ton; thus, there are no marginal costs between these two scenarios.

Table 8-48. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1999\$)	Annualized Average Cost-Effectiveness (\$/ton)	Marginal Costs (\$/ton)
Scenario 1	7%	\$0.0	\$0	—
	3%	\$0.0	\$0	—
Scenario 2	7%	\$12.5	\$2,167	\$2,167
	3%	\$10.9	\$1,898	\$1,898
Scenario 3	7%	\$12.5	\$2,167	N/A
	3%	\$10.9	\$1,898	N/A

The costs and emission reductions are flat between the scenarios because there is only one NO_x control available for these sources—SNCR.

Table 8-49 shows the total annualized costs for controlling both SO_2 and NO_x.

Table 8-49. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$0.0
	3%	$0.0
Scenario 2	7%	$18.7
	3%	$14.9
Scenario 3	7%	$33.8
	3%	$25.0

8.5.9 Results for Sulfur Recovery Plants

Table 8-50 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 23 percent for costs at a 7 or a 3 percent discount rate. The emissions reductions are the same for each scenario because of the few controls available between $1,000 and $10,000 per ton average cost.

Table 8-50. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Sulfur Recovery Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	59,766	7%	46,069	13,697
	59,766	3%	46,073	13,693
Scenario 2	59,766	7%	46,069	13,697
	59,766	3%	46,073	13,693
Scenario 3	59,766	7%	46,069	13,697
	59,766	3%	46,073	13,693

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-51 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 21 to 22 percent for costs at a 7 or a 3 percent discount rate. For this source category, the reductions vary little between scenarios because of the limited number of emission controls between $1,000 and $10,000 per ton.

Table 8-51. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Sulfur Recovery Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	651	7%	516	135
	651	3%	516	135
Scenario 2	651	7%	510	141
	651	3%	510	141
Scenario 3	651	7%	510	141
	651	3%	510	141

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-52 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $11.6 million with costs at a 7 or a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $847 per ton with costs at a 7 percent discount rate and $849 per ton with costs at a 3 percent discount rate, and the marginal costs are $847 per ton with costs at a 7 percent discount rate and $849 per ton at a 3 percent discount rate. There are no available controls between $4,000/ton and $10,000/ton, so there are no other marginal costs.

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce SO_2 emissions from these sources—sulfur recovery and/or tail gas treatment.

Table 8-52. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Sulfur Recovery Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$11.6	$847	—
	3%	$11.6	$849	—
Scenario 2	7%	$11.6	$847	$847
	3%	$11.6	$849	$849
Scenario 3	7%	$11.6	$847	N/A
	3%	$11.6	$849	N/A

Table 8-53 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $0.07 million to $0.52 million with costs at a 7 percent discount rate and from $0.05 million to $0.47 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $519 to $3,652 per ton with costs at a 7 percent discount rate and from $400 to $3,315 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $74,167 per ton with costs at a 7 percent discount rate and $68,833 per ton with costs at a 3 percent discount rate. There are no available controls between $4,000/ton and $10,000/ton, so there are no other marginal costs.

The average and marginal costs rise between the scenarios because of applications of SCR, a high cost/ton control for this type of source.

Table 8-54 shows the total annualized costs for controlling both SO_2 and NO_x.

8.5.10 Results for Primary Aluminum Ore Reduction Plants

Table 8-55 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 3 to 7 percent for costs at a 7 or 3 percent discount rate.

Table 8-53. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Sulfur Recovery Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.1	$519	—
	3%	$0.1	$400	—
Scenario 2	7%	$0.5	$3,652	$74,167
	3%	$0.5	$3,315	$68,833
Scenario 3	7%	$0.5	$3,652	N/A
	3%	$0.5	$3,315	N/A

Table 8-54. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Sulfur Recovery Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$11.7
	3%	$11.7
Scenario 2	7%	$12.1
	3%	$12.1
Scenario 3	7%	$12.1
	3%	$12.1

Table 8-55. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	47,552	7%	45,922	1,630
	47,552	3%	45,922	1,630
Scenario 2	47,552	7%	44,292	3,260
	47,552	3%	44,292	3,260
Scenario 3	47,552	7%	44,292	3,260
	47,552	3%	44,292	3,260

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-56 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 3 to 15 percent with costs at a 7 or 3 percent discount rate.

Table 8-56. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants[a]

Scenario	2015 Baseline Emissions	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	1,676	1,626	50
	1,676	1,626	50
Scenario 2	1,676	1,423	253
	1,676	1,421	255
Scenario 3	1,676	1,421	255
	1,676	1,421	255

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table 8-57 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $1.6 million to $7.2 million with costs at a 7 percent discount rate and from $1.0 million to $4.5 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $982 to $2,209 per ton with costs at a 7 percent discount rate and from $590 to $1,383 per ton with costs at a 3 percent discount rate. The marginal costs are $3,436 per ton with costs at a 7 percent discount rate and $1,383 per ton with costs at a 3 percent discount rate. There are no available controls between $4,000/ton and $10,000/ton, so there are no other marginal costs.

Table 8-57. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$1.6	$982	—
	3%	$1.0	$590	—
Scenario 2	7%	$7.2	$2,209	$3,436
	3%	$4.5	$1,383	$1,383
Scenario 3	7%	$7.2	$2,209	N/A
	3%	$4.5	$1,383	N/A

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce SO_2 emissions from these sources—a sulfuric acid plant.

Table 8-58 shows the annualized costs, resulting annualized average cost-effectiveness for each scenarios, and marginal costs between each scenario for NO_x control. The annualized control costs range from $0.04 million to $0.7 million with costs at a 7 percent discount rate and from $0.04 million to $0.4 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $740 to $2,639 per ton with costs at a 7 percent discount rate and from $509 to $1,764 per ton with costs at a 3 percent discount rate. The marginal costs range from $2,823 to $30,500 per ton with costs at a 7 percent discount rate. With costs at a 3 percent discount rate, the

Table 8-58. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$740	—
	3%	$0.0	$509	—
Scenario 2	7%	$0.6	$2,411	$2,823
	3%	$0.4	$1,764	$1,764
Scenario 3	7%	$0.7	$2,639	$30,500
	3%	$0.4	$1,764	N/A

marginal costs are $1,764 per ton between the $1,000/ton and $4,000/ton scenarios, but there is no marginal cost between the $4,000/ton and $10,000/ton scenarios because the impacts are the same.

The costs and NO_x emission reductions reflect LNB applications also with LNB + SNCR in a very few cases. It is the application of LNB + SNCR that leads to the high marginal cost for the $10,000/ton scenario at the 7 percent discount rate.

Table 8-59 shows the total annualized costs for controlling both SO_2 and NO_x.

The next seven BART source categories only have NO_x controls applied to their affected units because there are no SO_2 emissions from BART-eligible units in these source categories that can be controlled at under $10,000/ton (1999$). Hence, all the reductions and costs for the remaining source categories are only for NO_x, not SO_2.

8.5.11 Results for Lime Kilns

Table 8-60 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 21 to 56 percent for costs at a 7 or 3 percent discount rate.

Table 8-61 shows the annualized costs, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $2 million to $31.8 million with costs at a 7 percent discount rate and $4.3 million to $25.4 million with costs at a 3 percent discount rate. The annualized average

Table 8-59. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
Scenario 1	7%	$1.7
	3%	$1.0
Scenario 2	7%	$7.8
	3%	$5.0
Scenario 3	7%	$7.8[a]
	3%	$5.0

[a] The annual costs for Scenario 3 are actually $61,000 higher than for Scenario 2.

Table 8-60. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Lime Kilns

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	12,849	7%	10,166	2,683
	12,849	3%	8,378	4,471
Scenario 2	12,849	7%	8,378	4,471
	12,849	3%	5,696	7,153
Scenario 3	12,849	7%	5,696	7,153
	12,849	3%	5,696	7,153

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in this source category, both controlled and uncontrolled.

Table 8-61. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Lime Kilns

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$2.0	$745	—
	3%	$4.3	$953	—
Scenario 2	7%	$5.0	$1,118	$1,678
	3%	$25.4	$3,552	$8,858
Scenario 3	7%	$31.8	$4,446	$9,993
	3%	$25.4	$3,552	N/A

cost-effectiveness ranges from $745 to $4,446 per ton with costs at a 7 percent discount rate and from $953 to $3,552 per ton with costs at a 3 percent discount rate. The marginal costs are $1,678 per ton for reaching the $4,000/ton scenario and are $9,993 per ton between the $4,000/ton and $10,000/ton scenarios with costs at a 7 percent discount rate. The marginal costs are $8,858 per ton for reaching the $4,000/ton scenario, and there are no marginal costs for reaching the $10,000/ton scenario from the $4,000/ton scenario because the impacts are the same. These impacts reflect applications of LNB at $1,000/ton, SNCR at $4,000/ton, and SCR at $10,000/ton.

8.5.12 Results for Glass Fiber Processing Plants

Table 8-62 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 9 to 33 percent for costs at a 7 percent discount rate and from 12 to 33 percent for costs at a 3 percent discount rate.

Table 8-63 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0.5 million to $7.8 million with costs at a 7 percent discount rate and from $0.7 million to $6.8 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness ranges from $937 to $3,549 per ton with costs at a 7 percent discount rate and from $880 to $3,108 per ton with costs at a 3 percent discount rate. Marginal costs are $3,101 per ton for reaching the $4,000/ton scenario and $30,488 per ton between the $4,000/ton and $10,000/ton scenario with costs at a 7 percent discount rate and

Table 8-62. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Glass Fiber Processing Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	6,677	7%	6,109	568
	6,677	3%	5,902	775
Scenario 2	6,677	7%	4,561	2,116
	6,677	3%	4,561	2,116
Scenario 3	6,677	7%	4,479	2,198
	6,677	3%	4,479	2,198

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table 8-63. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Glass Fiber Processing Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.5	$937	—
	3%	$0.7	$880	—
Scenario 2	7%	$5.3	$2,505	$3,101
	3%	$4.8	$2,244	$3,057
Scenario 3	7%	$7.8	$3,549	$30,488
	3%	$6.8	$3,108	$25,402

$3,057 per ton for reaching the $4,000/ton scenario and $25,402 per ton between the $4,000/ton and $10,000/ton scenario with costs at a 3 percent discount rate. The impacts reflect application of LNB at $1,000/ton and $4,000/ton and then oxygen-firing under the $10,000/ton scenario.

8.5.13 Results for Municipal Incinerators

The analysis of municipal incinerators (>250 tons per day burn refuse capacity) shows the results for each scenario. Table 8-64 shows the NO_x emissions reductions achieved in the analysis for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 45 percent for costs at a 7 or 3 percent discount rate.

Table 8-64. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Municipal Incinerators[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	1,656	7%	1,656	0
	1,656	3%	1,656	0
Scenario 2	1,656	7%	912	744
	1,656	3%	912	744
Scenario 3	1,656	7%	912	744
	1,656	3%	912	744

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table 8-65 shows the annualized costs, annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0 to $1.1 million with costs at a 7 percent discount rate and from $0 to $0.9 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $1,478 per ton with costs at a 7 percent discount rate and $1,207 per ton with costs at a 3 percent discount rate. The marginal costs are $1,478 per ton for reaching the $4,000/ton scenario with costs at the 7 percent discount rate and $1,207 per ton at the 3 percent discount rate. Because there are no other controls between $4,000/ton and $10,000/ton, there are no additional reductions and hence no marginal costs between these two scenarios. The only available control measure for this source is SNCR.

Table 8-65. 2007 Cost and Cost-Effectiveness Results for BART-Eligible Municipal Incinerators

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$1.1	$1,478	$1,478
	3%	$0.9	$1,207	$1,207
Scenario 3	7%	$1.1	$1,478	N/A
	3%	$0.9	$1,207	N/A

8.5.14 Results for Coal Cleaning Plants

Table 8-66 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 46 percent for costs at a 7 or a 3 percent discount rate.

Table 8-66. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Coal Cleaning Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	1,110	7%	1,110	0
	1,110	3%	1,110	0
Scenario 2	1,110	7%	599	511
	1,110	3%	599	511
Scenario 3	1,110	7%	599	511
	1,110	3%	599	511

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table 8-67 shows the annualized costs, annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0 to $1.0 million with costs at a 7 percent discount rate and from $0 to $0.8 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $1,900 per ton with costs at a 7 percent discount rate and $1,534 per ton with costs at a 3 percent discount rate. The marginal costs are $1,900 per ton for reaching the $4,000/ton scenario with costs at a 7 percent discount rate and $1,534 per ton with costs at a 3 percent discount rate. Because there are no other controls between $4,000/ton and $10,000/ton, there are no additional reductions and hence no marginal costs between these two scenarios. Controls available to these sources are LNB and SNCR.

Table 8-67. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Coal Cleaning Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$1.0	$1,900	$1,900
	3%	$0.8	$1,534	$1,534
Scenario 3	7%	$1.0	$1,900	N/A
	3%	$0.8	$1,534	N/A

8.5.15 Results for Carbon Black Plants

Table 8-68 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0.2 to 2 percent for costs at a 7 or a 3 percent discount rate.

Table 8-69 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0.1 million to $0.2 million with costs at a 7 percent discount rate and from $0.006 million to $0.15 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness ranges from $957 to $1,608 per ton with costs at a 7 percent

Table 8-68. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Carbon Black Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	4,645	7%	4,638	7
	4,645	3%	4,638	7
Scenario 2	4,645	7%	4,525	120
	4,645	3%	4,525	120
Scenario 3	4,645	7%	4,525	120
	4,645	3%	4,525	120

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table 8-69. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Carbon Black Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.1	$957	—
	3%	$0.0	$830	—
Scenario 2	7%	$0.2	$1,608	$1,646
	3%	$0.1	$1,237	$1,237
Scenario 3	7%	$0.2	$1,608	N/A
	3%	$0.1	$1,237	N/A

discount rate and from $830 to $1,237 per ton with costs at a 3 percent discount rate. The marginal costs between the $1,000/ton and the $4,000/ton scenarios are $1,646/ton with costs at a 7 percent discount rate and $1,237/ton with costs at a 3 percent discount rate. Because there are no other controls between $4,000/ton and $10,000/ton, there are no additional reductions and hence no marginal costs between these two scenarios. NO_x controls available to these sources are SNCR and SCR, and the cost per ton for these controls is fairly similar for these sources in this analysis.

8.5.16 Results for Phosphate Rock Processing Plants

Table 8-70 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 7 percent for costs at either a 7 or 3 percent discount rate.

Table 8-70. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Phosphate Rock Processing Plants

Scenarios	2015 Baseline Emissions	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	719	719	0
	719	719	0
Scenario 2	719	674	45
	719	671	48
Scenario 3	719	671	48
	719	671	48

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table 8-71 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0 to $0.2 million with costs at a 7 or 3 percent discount rate. The annualized average cost-effectiveness ranges from $1,978 to $4,646 per ton with costs at a 7 percent discount rate and from $0 to $3,221 per ton with costs at a 3 percent discount rate. The marginal costs between the $1,000/ton and the $4,000/ton scenarios are $1,978 per ton, while the marginal costs between the $4,000/ton and the $10,000/ton scenarios are $44,667 per ton with costs at a 7 percent discount rate. With costs at a 3 percent discount rate, the marginal costs between the $1,000/ton and the $4,000/ton scenarios are $3,221 per ton, and there is no marginal cost between the $4,000/ton and the $10,000/ton scenario because the impacts are the same for each scenario. The only available NO_x control for this source is LNB + SNCR.

Table 8-71. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Phosphate Rock Processing Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
Scenario 1	7%	$0.0	$0	—
	3%	$0.0	$0	—
Scenario 2	7%	$0.1	$1,978	$1,978
	3%	$0.2	$3,221	$3,221
Scenario 3	7%	$0.2	$4,646	$44,667
	3%	$0.2	$3,221	N/A

8.5.17 Results for Secondary Metal Production Facilities

Table 8-72 shows the NO_x emissions reductions achieved in the analyses for each scenarios. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 2 to 3 percent for costs at either a 7 or 3 percent discount rate.

Table 8-72. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Secondary Metal Production Facilities

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
Scenario 1	1,377	7%	1,352	25
	1,377	3%	1,352	25
Scenario 2	1,377	7%	1,343	34
	1,377	3%	1,342	35
Scenario 3	1,377	7%	1,342	35
	1,377	3%	1,342	35

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in this source category, both controlled and uncontrolled.

Table 8-73 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from \$0.01 million to \$0.12 million with costs at a 7 percent discount rate and from \$0.01 to \$0.04 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness ranges from \$760 to \$1,800 per ton with costs at a 7 percent discount rate and from \$511 to \$1,247 per ton with costs at a 3 percent discount rate. With costs at a 7 percent discount rate, the marginal costs between the \$1,000/ton and the \$4,000/ton scenarios are \$2,000 per ton and the marginal costs between the \$4,000/ton and the \$10,000/ton scenarios are \$9,000 per ton. With costs at a 3 percent discount rate, the marginal costs between the \$1,000/ton and the \$4,000/ton scenarios are \$3,100/ton, and there are no marginal costs between the \$4,000/ton and the \$10,000/ton scenarios because the impacts are the same. Available NO_x controls are LNB and the more expensive LNB + SNCR.

Table 8-73. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Secondary Metal Processing Facilities

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
Scenario 1	7%	$0.0	$760	—
	3%	$0.0	$511	—
Scenario 2	7%	$0.0	$1,088	$2,000
	3%	$0.0	$1,247	$3,100
Scenario 3	7%	$0.1	$1,800	$9,000
	3%	$0.0	$1,247	N/A

8.6 Caveats and Limitations of the Analyses

A number of caveats and limitations are associated with these analyses.

- As noted above in Section 8.5, for a large number of non-EGU BART source categories, no SO_2 or NO_x controls exist. There are no impacts for 8 of the 25 non-EGU source categories because no control measures are available to reduce SO_2 and NO_x from these categories within AirControlNET or any other documentation that has been found in the course of completing this analysis. For seven source categories only NO_x reductions take place in these analyses because no control measures are available within AirControlNET or no controls are available at $10,000/ton or below. Finally, there are a total 10 source categories for which both SO_2 and NO_x reductions take place in these analyses.

- Control programs implemented as command-and-control regulation, as this analysis models controls to affected non-EGU sources, will lead to less-induced technological innovation when compared to a market incentives-based approach (e.g., a cap-and-trade program).

- The technologies applied in these analyses do not reflect emerging control devices that could be available in future years to meet any BART requirements in SIPs or upgrades to current devices that may serve to increase control levels. For example, there is increasing use of SCR/SNCR hybrid technologies that can serve to lower the expected capital costs and lead to NO_x control at high levels (90 percent).

- Fuel switching is not considered as a way for BART-eligible units, especially industrial boilers, to meet potential BART requirements in SIPs. Fuel switching can consist of coal-fired sources switching from high- to low-sulfur coals (e.g., Powder River Basin coals). Many power plants have used this technique to meet SO_2 requirements imposed by the Acid Rain Program and by various regulations, but industrial sources have used it less frequently.

- There is a considerable range of equipment lives for the control devices applied in these analyses. For example, the equipment life for SCR can range from 10 to 40 years. We chose a middle point from this range to use in these analyses. To the extent that we underestimated the actual equipment life from use of these devices, we overestimate the annual costs of these controls and vice versa.

- Labor and energy rates and other parameters to the cost estimates are estimated based on nationwide rates instead of regional and local rates. Using nationwide parameter estimates introduces some uncertainty in these estimates at a source-specific level.

- The emission reductions and controls that will be imposed on petroleum refineries as a result of various New Source Review settlements are not included in our regulatory baseline. Thus, this analysis is likely to overestimate costs of BART compliance to many BART-eligible units at petroleum refineries.

- EPA wants to identify some unquantified costs as limits to its analysis. These costs include the costs of State administration of the program, which we believe are modest. There also may be unquantified costs of transitioning to BART, such as the costs associated with the possible retirement of smaller or less-efficient non-EGU units and employment shifts as workers are retrained at the same company or reemployed elsewhere in the economy.

- Recent research suggests that the total social costs of a new regulation may be affected by interactions between the new regulation and preexisting distortions in the economy, such as taxes. In particular, if cost increases due to a regulation are reflected in a general increase in the price level, the real wage received by workers may be reduced, leading to a small fall in the total amount of labor supplied. This "tax interaction effect" may result in an increase in deadweight loss in the labor market and an increase in total social costs. Although there is a good case for the existence of the tax interaction effect, recent research also argues for caution in making prior assumptions about its magnitude. However, there are currently no government-wide economic analytical guidelines that discuss the tax interaction effect and its potential relevance for estimating federal program costs and benefits. The limited empirical data available to support quantification of any such effect lead to this qualitative identification of the costs.

8.7 References

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U.S. Office of Management and Budget (OMB). September 17, 2003. Circular A-4. "New Guidelines for the Conduct of Regulatory Analysis." Available at <http://www.whitehouse.gov/omb/circulars/a004/a-4.html>.

SECTION 9

STATUTORY AND EXECUTIVE ORDER IMPACT ANALYSES

Impact analysis is a general term used to describe various economic analyses that supplement estimates of the benefits and costs of a rulemaking. These analyses are conducted to meet the statutory and administrative requirements imposed by Congress and the Executive Office. This chapter will address the requirements of the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) and the Unfunded Mandates Reform Act (UMRA).

9.1 Small Entity Impacts

The Regulatory Flexibility Act (5 U.S.C. § 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have "a significant economic impact on a substantial number of small entities" 5 U.S.C. § 605(b). Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of the this proposed rulemaking on small entities, small entity is defined as: (1) a small business that is identified by the North American Industry Classification System (NAICS) Code, as defined by the Small Business Administration (SBA); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less that 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Table 9-1 lists EGU entities potentially impacted by this proposed rule with applicable NAICS code. BART also has 25 non-EGU source categories as defined by Clean Air Act. Table 9-2 provides a list of example non-EGU entities with applicable NAICS codes and the Small Business Administrations Size Standards. States implementing the rule may choose to regulate source categories in addition to those listed in Table 9-1 and 9-2.

Table 9-1. Potentially Regulated EGU Categories and Entities[a]

Category	NAICS Code[b]	Examples of Potentially Regulated Entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	22112[c]	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/tribal government	22112[c]	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric generating units only.
[b] North American Industry Classification System.
[c] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

Table 9-2. Examples of Potentially Regulated Non-EGU Categories and Entities

BART Source Category Name	NAICS Code[a]	NAICS Description	Size Standard[b]
Fossil Fuel-Fired Industrial Boilers (>250 MMBTU heat input per hour)	Various manufacturing industries	Varied	Varied
Petroleum Refineries	324110	Petroleum Refineries	1500 Employees
Kraft Pulp Mills	322110	Pulp Mills	750 Employees
Portland Cement Plants	327310	Cement Manufacturing	750 Employees
Hydrofluoric, Sulfuric, and Nitric Acid Plants	325	Chemical Manufacturing	1000 Employees
Primary Aluminum Ore Reduction Plants	331312	Primary Aluminum Production	750 Employees
Chemical Process Plants	325	Chemical Manufacturing	1000 Employees
Iron and Steel Mill Plants	3311	Iron and Steel Mill and Ferroalloy Manufacturing	1000 Employees

[a] North American Industry Classification System.
[b] Small Business Administration Size Standards. http://www.sba.gov/size/sizetable2002.html.

According to the SBA size standards for NAICS code 221112 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule.[1] This rule would not establish requirements applicable to small entities. Instead, it would require states to develop, adopt, and submit SIP revisions that would achieve the necessary SO_2 and NO_x emissions reductions, and would leave to the states the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose the sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could definitely not predict the effect of the rule on small entities. Although not required by the RFA, a general analysis of the potential impact on small entities of the BART Scenario 2 is conducted for informational purposes.

For the small business analysis, EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of sales (cost-to-sales ratio or CSR) using revenues, control costs, and accounting measures of profit. The analysis assesses the burden of the rule by assuming the affected firms absorb the control costs, rather than passing them on to consumers in the form of higher prices. One drawback for this approach is that it does not consider interaction between producers and consumers in a market context. Therefore, it likely overstates the impacts on firms affected by the rule and understates the impacts on consumers. We used the following equation to compute the CSR:

$$\text{CSR } (\%) = \frac{\sum_{i=1}^{n} \text{TACC}}{\text{TR}_j} \tag{9.1}$$

where

TACC = total annual compliance costs,

i = indexes the number of affected units owned by company j,

[1] See Michigan v. EPA, 213 F.3d 663, 668-69 (D.C. Cir. 2000), cert. den. 121 S.Ct. 225, 149 L.Ed.2d 135 (2001). An agency's certification need consider the rule's impact only on entities subject to the rule.

n = number of affected plants, and

TRj = total revenue of ultimate parent company j.

9.1.1 EGU Sector Small Business Impacts

For proposal, the engineering analysis conducted for the rulemaking identified 302 EGU units potentially affected by the rule. Using unit ORIS[2] numbers and the Energy Information Administration's publicly available 2002 electric generator databases (Form EIA 860 and Form EIA 861), we identified utility names and nameplate capacity for affected units. EPA identified 66 ultimate parent companies in publically available company databases,[3] collected sales and employment information, and estimated annual electricity output rates for these companies. After identifying these units, we excluded units that are located in CAIR regions in order to identify those units most likely affected by the BART regulatory program. The following sections describe the results of the data collection.

As previously discussed, the U.S. Small Business Administration established a table of size standards, matched to North American Industry Classification System (NAICS) industries that EPA has traditionally used to classify affected entities as small businesses. The size standard for firms primarily engaged in the generation, transmission, and/or distribution of electric energy for sale is total electric less than or equal to 4 million megawatt hours. In order to classify affected parent companies as small or large using this standard, we collected data on nameplate capacity for each ultimate parent company that could be consistently matched with the electric generator database.[4] Next, we converted this measure to megawatt hours using the following formula:

$$\text{Capacity Factor} \times \text{NamePlate Capacity (MW)} \times \text{standard hours per year}$$

[2]An ORIS code is a 4 digit number assigned by the Energy Information Administration (EIA) at the U.S. Department of Energy to power plants owned by utilities.

[3]These include common databases such as Hoover's (2001) and ReferenceUSA (2001). We emphasize that this is the ultimate parent company in the ownership structure. Therefore it may be different than the owner identified in Forms EIA 860 and EIA 861.

[4]This approach leads to a conservative estimate of ultimate parent company nameplate capacity because all units in the EIA database could not be matched to an ultimate parent at this time. Therefore, we may under estimate the true ultimate parent name plate capacity.

and assumed an average capacity factor of 85 percent and 8,760 standard hours per year. For Scenario 2 using this approach, we identified one affected small firm. We estimate this small business will experience a cost-to-sales ratio of approximately 3 percent.

9.1.2 Non-EGU Sector Small Business Impacts

The engineering analysis conducted for the rulemaking identified over 2,000 records associated with affected non-EGU units potentially affected by the rule. Using publicly available sales and employment databases, plant names, and locations, we identified 279 entities and potential owners.

To classify affected ultimate entities as small or large, EPA collected information on facility names, parent company sales, and parent company employment data. Data were compared with the appropriate size standard, and entities were classified as small or large. For example, ultimate parent companies of cement producers with employment exceeding 750 employees were classified as a large companies. This process identified 36 small companies, 195 large companies. The remaining 48 entities were either government-owned (25 entities, primarily state universities) or parent ownership could not be definitively identified using available databases (23 entities). Those entities whose parent ownership could not be definitively identified were not included in the analysis.

Under Scenario 2 using the CSR approach described above, EPA found that five non-EGU source category small businesses may experience a 3 percent CSR level or higher. Two may experience CSRs between 1 and 3 percent, and the remaining small company CSRs are below one percent. The median CSR for non-EGU source category small businesses is 0.3 percent and ranges from 0 to 20 percent.

9.2 Unfunded Mandates Reform Act (UMRA)

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

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

The EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under Section 203 of the UMRA a small government agency plan. Furthermore, in a manner consistent with the intergovernmental consultation provisions of Section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

Notwithstanding these issues, EPA conducted an analysis that would be required by UMRA if its statutory provisions applied, and the EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

9.2.1 EGU UMRA Analysis

Using unit ORIS numbers and the Energy Information Administration's publicly available 2002 electric generator databases (Form EIA 860 and Form EIA 861), we identified affected units that were owned by states or municipalities. There were seven units that met this criteria and two state government entities owned these units.

Under Scenario 2, the total annual compliance costs for affected governments are estimated to be approximately \$150 million (1999\$). Approximately 2.7 million households live in governmental jurisdictions that may potentially be impacted by this rulemaking.

9.2.2 Non-EGU UMRA Analysis

This section of the analysis focuses upon the impacts for government entities owning BART-eligible units in non-EGU source categories. Using lists of affected facility names, EPA identified 25 affected entities that were owned by states or municipalities (primarily universities). Under Scenario 2, the total annual compliance costs for the governments owning the 25 affected entities are estimated to be approximately $40 million (1999$).

9.3 Paperwork Reduction Act

The rule clarifies, but does not modify the information collection requirements for BART. Therefore, this action does not impose any new information collection burden. However, the OMB has previously approved the information collection requirements contained in the existing regulations [40 CFR Part 51] under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2060-0421, EPA ICR number 1813.04.

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

9.4 Executive Order 13132: Federalism

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

We have concluded that this rule, promulgating the BART guidelines, will not have federalism implications, as specified in section 6 of the Executive Order 13132 (64 FR

43255, August 10, 1999), because it will not have substantial direct effects on the states, nor substantially alter the relationship or the distribution of power and responsibilities between the states and the federal government. Nonetheless, we consulted with a wide scope of state and local officials, including the National Governors Association, National League of Cities, National Conference of State Legislatures, U.S. Conference of Mayors, National Association of Counties, Council of State Governments, International City/County Management Association, and National Association of Towns and Townships, during the course of developing this rule.

9.5 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have Tribal implications."

This rule does not have tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the federal government and Indian Tribes. The CAA and the TAR establish the relationship of the federal government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. This rule does not have tribal implications, and Executive Order 13175 does not apply to this rulemaking.

9.6 Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

The BART rule and guidelines are not subject to the Executive Order, because the rule and guidelines do not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the control strategies considered in this rulemaking will further improve air quality and will further improve children's health.

9.7 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 Fed. Reg. 28355 [May 22, 2001]), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This rule is not a "significant energy action," because it has less than a 1 percent impact on the cost of energy production and does not exceed other factors described by OMB that may indicate a significant adverse effect. (See, "Guidance for Implementing E.O. 13211," OMB Memorandum 01-27 [July 13, 2001] www.whitehouse.gov/omb/memoranda/m01-27.html) Specifically, the presumptive requirements for EGUs for this rule when fully implemented are expected have a 0.25 percent impact on the cost of energy production for the nation in 2015. States must use the guidelines in making BART determinations for power plants with a generating capacity in excess of 750 MW. Our analysis evaluates the impact of the presumptive requirements for these sources and does not consider any possible additional controls for EGU sources or non-EGU sources that states may require. Although states may choose to use the guidelines in establishing BART limits for non-EGUs , ultimately states will determine the sources subject to BART and the appropriate level of control for such sources.

We are finalizing the reproposal of the rule following the D.C. Circuit's remand of the BART provisions in the 1999 regional haze rule. The 1999 regional haze rule provides substantial flexibility to the states, allowing them to adopt alternative measures such as a trading program in lieu of requiring the installation and operation of BART. This rulemaking does not restrict the ability of the states to adopt alternative measures. The regional haze rule accordingly already provides an alternative to BART that reduces the overall cost of the regulation and its impact on the energy supply. The BART rule itself offers flexibility by offering the choice of meeting SO_2 requirements between an emission rate and a removal rate.

For a state that chooses to require case-by-case BART, this rule would establish presumptive levels of controls for SO_2 and NO_x for certain EGUs that the state finds are subject to BART. Based on its consideration of various factors set forth in the regulations; however, a state may conclude that a different level of control is appropriate. The states will accordingly exercise substantial intervening discretion in implementing the final rule. Additionally, we have assessed that the compliance dates for the rule will provide adequate time for EGUs to install the required emission controls.

9.8 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer Advancement Act of 1995 (NTTAA), Public Law No. 104-113, §12(d)(15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the EPA decides not to use VCS.

This guidance does not involve technical standards; thus, EPA did not consider the use of any VCS.

9.9 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," requires federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. According to EPA guidance,[5] agencies are to assess whether minority or low-income populations face risks or a rate of exposure to hazards that are significant and that "appreciably exceed or is likely to appreciably exceed the risk or rate to the general population or to the appropriate comparison group" (EPA, 1998).

In accordance with E.O. 12898, the Agency has considered whether this rule may have disproportionate negative impacts on minority or low income populations. Negative impacts to these subpopulations that appreciably exceed similar impacts to the general population are not expected, because the Agency expects this rule to lead to reductions in air pollution emissions and exposures generally.

[5] U.S. Environmental Protection Agency, 1998. Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. Office of Federal Activities, Washington, DC, April, 1998.

9.10 Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the *Federal Register*. A Major rule cannot take effect until 60 days after it is published in the *Federal Register*. This action is a "major rule" as defined by 5 U.S.C. 804(2).

9.11 References

Hoover's. 2001. Hoover's Online Data Service for Dun & Bradstreet. Available at <http://www.hoovers.com/free/>.

InfoUSA. 2001. InfoUSA Sales Solutions Database of Company Sales. Available at <http://www.infousa.com/>.

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SECTION 10

COMPARISON OF BENEFITS AND COSTS

The estimated social costs to implement BART, as described in this document, range from approximately \$0.3 to \$2.9 billion annually for 2015 depending on the actions taken by States and the discount rate (1999 dollars, 3 percent or 7 percent discount rate). Thus, the annual net benefits (social benefits minus social costs) range from \$1.9 + B billion or \$12.0 + B billion annually (1999 dollars, based on State actions taken and discount rates of 3 percent or 7 percent) in 2015. (B represents the sum of all unquantified benefits and disbenefits of the regulation.) Therefore, implementation of this rule is expected, based purely on economic efficiency criteria, to provide society with a significant net gain in social welfare, even given the limited set of health and environmental effects we were able to quantify. Addition of ozone-, directly emitted $PM_{2.5}$-, mercury-, acidification-, and eutrophication-related impacts would likely increase the net benefits of the rule. Table 10-1 presents a summary of the benefits, costs, and net benefits of the final rule. The benefits and costs of a less stringent and a more stringent option than Scenario 2 are also presented in Table 10-1.

The benefits and costs reported for BART represent estimates that assume implementation of a complete CAIR program (includes the CAIR promulgated rule and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware) in the baseline. Annual SO_2 and NO_x controls for Arkansas are included in the modeling used to develop the CAIR baseline estimates resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program and a slight understatement of the benefits and costs for BART. The recently promulgated CAMR has not been considered in the baseline used to conduct the analysis of benefits and costs for BART. As with any complex analysis of this scope, a number of uncertainties are inherent in the final estimate of benefits and costs that are described fully in Chapters 4, 7, and 8 of the RIA.

Table 10-1. Summary of Annual Benefits, Costs, and Net Benefits of the Clean Air Visibility Rule—2015[a] (billions of 1999 dollars)

Description	Scenario 1	Scenario 2	Scenario 3
Social costs[b]			
3 percent discount rate	\$0.4	\$1.4	\$2.3
7 percent discount rate	\$0.3	\$1.5	\$2.9
Social benefits[c,d,e]			
3 percent discount rate	\$2.6 + B	\$10.1 + B	\$14.3 + B
7 percent discount rate	\$2.2 + B	\$8.6 + B	\$12.2 + B
Health-related benefits:			
3 percent discount rate	\$2.5	\$9.8	\$13.9
7 percent discount rate	\$2.1	\$8.4	\$11.8
Visibility benefits	\$0.08	\$0.24	\$0.42
Net benefits (benefits-costs)[e,f]			
3 percent discount rate	\$2.2 + B	\$8.7 + B	\$12.0 + B
7 percent discount rate	\$1.9 + B	\$7.1 + B	\$9.3 + B

[a] All estimates are rounded to two significant digits for ease of presentation and computation. A complete CAIR program that includes the CAIR promulgated rule and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware is assumed to implemented in the baseline for the BART analysis. Annual SO_2 and NO_x controls for Arkansas are included in the modeling used to develop these estimates resulting in a minimal overstatement of the benefits and costs for the complete CAIR program and potentially a minimal understatement of the benefits and costs for BART. The impact of the recently promulgated Clean Air Mercury Rule was not been considered in the baseline for BART.

[b] Note that costs are the annualized total costs of reducing pollutants including NO_x and SO_2 for the EGU and non-EGU source categories nationwide in 2015. The discount rate used to conduct the analysis impacts the control strategies chosen for the non-EGU source category resulting in greater level of controls under the 3 percent discount rate for Scenario 1.

[c] As this table indicates, total benefits are driven primarily by PM-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide (with the exception of visibility) and are associated with NO_x and SO_2 reductions. Visibility benefits represent benefits in Class I areas in the southeastern and southwestern United States. Ozone benefits are likely to occur with BART, but are not estimated in this analysis.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in Table 1-4.

[e] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 4. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

[f] Net benefits are rounded to the nearest \$100 million. Columnar totals may not sum due to rounding.

10.1 References

U.S. Environmental Protection Agency (EPA). September 2000. *Guidelines for Preparing Economic Analyses.* EPA 240-R-00-003.

U.S. Office of Management and Budget (OMB). 2003. Circular A-4 Guidance to Federal Agencies on Preparation of Regulatory Analysis.

APPENDIX A

BART INDUSTRY-SECTOR IMPACTS

EPA estimates the direct costs of implementing the BART guidance to range from$0.3 to $2.9 billion in 2015 in the BART region. Given possible impacts of this guidance on electricity generators and manufacturing industries, we believe it is important to gauge the extent to which the guidance might affect other parts of the economy. To do so, we conducted a limited analysis of the economy-wide effects of implementing BART. This has been done for three alternative implementation scenarios: “Scenario 1,” “Scenario 2,” and “Scenario 3.”

We were particularly interested in learning how possible changes in electricity prices might affect industry sectors that are large electricity users and how changes in manufactured-goods prices might affect other businesses and households. The models we employed indicated those impacts would be small, even without incorporating the beneficial economic effects of BART-related air quality improvements such as improved worker health and productivity. Rather, our analyses continue to show that the value of even the limited subset of BART benefits we were able to quantify substantially outweigh implementation costs. The degree to which projected benefits exceed projected costs would be even greater if we were able to include a number of other beneficial effects, such as a reduction in acid rain damage and lowering of nitrogen deposition.

By focusing only on cost-side spillover effects on the economy, the industry-sector impacts projected by our macroeconomic model are likely overstated, primarily because the positive market impacts of the BART guidance on labor availability and productivity are excluded. In this regard, an independent panel of experts has encouraged EPA to work toward incorporating both beneficial and costly effects when modeling the economy-wide consequences of regulation. EPA is actively working to develop this capability.

Although the macroeconomic model employed has yet been configured to include the indirect economic benefits of air quality improvements, EPA employed a computable general equilibrium (CGE) model to gauge the potential magnitude of the economy-wide effects of BART implementation costs. The model, called EMPAX-CGE, is currently in peer review. As with all models, this tool has its strengths and weaknesses. The results of the CGE analysis show small impacts of the BART guidance on energy-intensive and manufacturing industries. For example, production changes for the chemical manufacturing industry are estimated at less than –0.1 percent in 2015.

Furthermore, EMPAX-CGE is not configured to capture the beneficial economic consequences of the increased labor availability and productivity expected to result from BART-related air quality improvements. If these labor productivity improvements were included, the small production output decreases projected by the model might be partially or entirely offset. EPA continues to investigate the feasibility of incorporating labor productivity gains and other beneficial effects of air quality improvements in CGE models. The analysis of BART by the EMPAX-CGE general equilibrium model follows.

A.1 EMPAX-CGE Regional Macroeconomic Analysis of BART

The BART guidance reduces emissions of SO_2 and NO_x from electricity generation and combustion manufacturing emissions sources to improve air quality.[1] To complement the analysis of BART effects on electricity generation conducted using IPM[2] and the effects on specific manufacturing sectors conducted using AirControlNET,[3] the macroeconomic implications of this guidance have been estimated using EPA's EMPAX-CGE model. EMPAX-CGE is a macroeconomic simulation model developed by RTI International (RTI) for EPA's Office of Air Quality Planning and Standards (OAQPS).

The focus of this analysis of the BART guidance is examining the sectoral and regional distribution of economic effects across the U.S. economy. This appendix section discusses the EMPAX model, the approach used to incorporate electricity-sector results from IPM, and the results of the macroeconomic analysis. Detailed results for the BART Scenario 2 are presented in Sections A.1.4 through A.1.7. Next in Section A.1.8, comparisons of Scenarios 1 and 3 for the BART guidance are shown for domestic industrial output and gross domestic product (GDP). Section A.1.9 discusses alternative methods of linking EMPAX-CGE to the IPM model results for electricity and consequences for the EMPAX-CGE results. Finally, Section A.2 provides additional information on the EMPAX-CGE model.

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[1]See <http://www.epa.gov/cleanair2004/> for details.

[2]See <http://www.epa.gov/airmarkt/epa-ipm/> for complete IPM documentation.

[3]See <http://www.epa.gov/ttn/ecas/AirControlNET.htm> for complete AirControlNET documentation.

Please note that this analysis focuses on electricity-sector and relevant manufacturing-sector impacts of the BART guidance as estimated by IPM and AirControlNET. It does not account for other economic and noneconomic effects, especially the substantial economic and health benefits associated with reduced emissions.

A.1.1 Background and Summary of EMPAX-CGE Model[4]

EMPAX was first developed in 2000 to support the economic analysis of EPA's maximum achievable control technology (MACT) rules controlling emissions from three categories of combustion sources (reciprocating internal combustion engines, boilers, and turbines). The initial framework consisted of a national multimarket partial-equilibrium model with linkages between manufacturing industries and the energy sector. Effects of combustion rules on these industries were estimated through their influence on energy prices and output. Modified versions of EMPAX were subsequently used to analyze economic impacts of strategies for improving air quality in the Southern Appalachian mountain region.

Recent work on EMPAX has extended its scope to cover all aspects of the U.S. economy at a regional level in either static or dynamic modes (the dynamic version of EMPAX is used in this analysis). Although major regulations directly affect a large number of industries, substantial indirect impacts can also result from changes in production, input use, income, and household consumption patterns. Consequently, EMPAX now includes economic linkages among all industrial and energy sectors as well as households that supply factors of production and purchase goods (i.e., a CGE framework). This gives the version of EMPAX called EMPAX-CGE the ability to trace economic impacts as they are transmitted throughout the economy and allows it to provide critical insights to policy makers evaluating the magnitude and distribution of costs associated with environmental policies. The EMPAX-CGE model was used to investigate macroeconomic impacts of the Clean Air Interstate Rule, predecessor to BART.[5]

The dynamic version of EMPAX-CGE employed in this analysis of the BART guidance is an intertemporally optimizing model. Agents have perfect foresight and maximize utility across all time periods subject to budget constraints, while firms maximize profits subject to technology constraints. Nested constant elasticity of substitution (CES) functions are used to portray substitution possibilities available to producers and consumers.

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[4]See Section A.2 for additional details on the EMPAX-CGE model.

[5]See <http://www.epa.gov/cair>.

Along with the underlying data, the nesting structures and associated substitution elasticities define current production technologies and possible alternatives. Most industries have constant returns to scale with the exception of fossil-fuel and agriculture industries that have decreasing returns to scale as a result of the use of factors in fixed supply (land and inputs of primary fuels, respectively).

The economic data in this CGE model come from state-level information provided by the Minnesota IMPLAN Group, and the energy data come from the DOE's Energy Information Agency (EIA). In the dynamic version of EMPAX-CGE, these data are used to define five regions within the United States, each containing 17 industries and four types of households classified by income.[6] The five regions have been selected to preserve important regional differences in electricity generation technologies, and 17 industries are included that cover five important types of energy (coal, crude oil, electricity from fossil and nonfossil generation, natural gas, and refined petroleum), the energy-intensive industries most likely to be affected by environmental policies, and the remaining sectors of the economy.

Four sources of economic growth are included: technological change from improvements in energy efficiency, growth in the available labor supply from population growth and changes in labor productivity, increases in stocks of natural resources, and capital accumulation. Changes in energy use per unit of output are modeled through exogenous autonomous energy efficiency improvements (AEEI). The baseline solution in EMPAX-CGE matches, as closely as possible, EIA forecasts for energy production by fuel type, energy prices, fuel consumption by industry, industrial output, and regional economic growth through 2025.[7]

Distortions associated with the existing tax structure in the United States have been included in EMPAX-CGE. A wide range of theoretical and empirical literature has examined "tax interactions" and found that they can substantially alter costs of environmental (and other) policies. The IMPLAN economic database used by EMPAX-CGE includes information on some types of taxes, which have been combined with other data sources to cover important distortions from capital and income taxes.

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[6]Static versions of EMPAX-CGE have more industries and households because they do not have to solve for multiple time periods simultaneously and, consequently, have few computational constraints on the number of industries and households.

[7]EIA forecasts from the *Annual Energy Outlook 2003* (AEO) (EIA, 2003) are used in this analysis.

A.1.2 Modeling Approach for Electricity and Manufacturing Policies

EMPAX-CGE can be used to analyze a wide array of policy issues and is capable of estimating how a change in a single part (or multiple parts) of the economy will influence producers and consumers across the United States. However, although CGE models have been used extensively to analyze climate policies that limit carbon emissions from electricity production,[8] some other types of emissions policies are more difficult to consider. Unlike carbon dioxide, emissions of pollutants such as SO_2, NO_x, and mercury are not necessarily proportional to fuel use.

These types of emissions can be lowered by a variety of methods: fuel switching from high- to low-sulfur coal, moving from coal- to gas-fired generation, and/or installing retrofit equipment designed to reduce emissions. However, the boiler- and firm-specific natures of these decisions, and their costs and effects, cannot be adequately captured by the more general structure of a CGE model. In addition, because of the ways that retrofits (and possibly the construction of new generating units) can affect electricity prices, manufacturing costs, and fuel use, a detailed characterization of the electricity and industrial markets is preferable when estimating implications of policies like the BART guidance. For these reasons, we developed an interface that allows linkages between EMPAX-CGE and the IPM and AirControlNET models.

IPM is a comprehensive model of electricity generation and transmission in the United States. The model contains data on all generating units available to dispatch electricity to the national grid, their existing equipment configurations and fuel consumption, transmission constraints, and generating costs. It includes characteristics of new units and retrofits that can be built and/or installed. IPM is capable of estimating how electric utilities will respond to policies by determining the least-cost methods of generating sufficient electricity to meet demands, while meeting emissions reduction (and other) objectives.

However, IPM does not fully consider how changes in the electricity sector, or electricity prices, will affect the rest of the U.S. economy. Combining the strengths of IPM (disaggregated unit-level analyses of electricity policies) with the strengths of CGE models (macroeconomic effects of environmental policies) allows investigation of economy-wide implications of policies that would normally be hard to estimate consistently and effectively. For regulations affecting electricity generation like the BART guidance, which require a very

[8]See, for example, the analyses of energy/climate using CGE models organized by the Stanford University Energy Modeling Forum (http://www.stanford.edu/group/EMF/home/index.htm).

disaggregated level of analysis, IPM can determine for EMPAX-CGE a number of electricity market outcomes needed to evaluate macroeconomic implications of policies. The linkage with IPM then allows EMPAX-CGE to take these findings and use them in "counterfactual" policy evaluations.

Among the many results provided by IPM, several can potentially have significant implications for the rest of the economy including changes in electricity prices, fuel consumption by utilities, fuel prices, and changes in electricity production expenditures. EMPAX-CGE is capable of simultaneously incorporating some or all of these IPM findings, depending on the desired type and degree of linkage between the two models. At the regional level, EMPAX-CGE can match changes estimated by IPM for the following variables:

- electricity prices (percentage change in retail prices)
- coal and gas consumption for electricity (percentage changes in Btus)
- coal and gas prices (percentage changes in prices)
- coal and gas expenditures ($ changes—Btus of energy input times $/MMBtu)
- capital costs ($ changes)
- fixed operating costs ($ changes)
- variable operating costs ($ changes)

AirControlNET is a PC-based relational database tool for conducting control strategy and costing analysis. It overlays a detailed control measure database on EPA emissions inventories to compute source- and pollutant-specific emission reductions and associated costs at various geographic levels (national, regional, local). It contains a database of control measures and cost information for reducing the emissions of criteria pollutants (e.g., NO_x, SO_2, VOC, PM_{10}, $PM_{2.5}$, NH_3) as well as CO and Hg from point (utility and nonutility), area, nonroad, and mobile sources as provided in EPA's National Emission Inventory (NEI). For the industries affected by the BART guidance, AirControlNET provides estimates of cost changes by industry and region of the country to the EMPAX-CGE model.

For EMPAX-CGE to effectively incorporate these IPM and AirControlNET data on changes in costs, they have to be expressed in terms of the productive inputs used in CGE models (i.e., capital, labor, and material inputs produced by other industries). Rather than assume these costs represent a proportional scaling up of all inputs to the industries in

EMPAX-CGE, we use Nestor and Pasurka (1995) data on purchases made by industries for environmental protection reasons to allocate these additional expenditures across inputs within EMPAX-CGE. Once these expenditures are specified, the incremental costs from IPM and AirControlNET can be used to adjust the production technologies and input purchases by electricity generation in the CGE model.

A.1.3 Modeling Methodology for the BART Guidance

The macroeconomic impacts of the BART guidance, as simulated by CGE models, will be a function of the methodology used to link IPM and AirControlNET to EMPAX-CGE and the economic interactions accounted for by the CGE model. Initial effects will revolve around how using additional resources in electricity generation and manufacturing draws some capital, labor, and materials from other sectors of the economy. This, in turn, may affect prices in markets supplying inputs to these industries. Similarly, changes in coal and gas use by electric utilities and associated impacts on their prices will have implications for the rest of the economy (although any spillovers in coal markets will have limited effects outside of electricity because most is used for generation). In addition, any electricity or fuel price increases associated with these initial effects will encourage improvements in energy efficiency, switching to alternate forms of energy (increases in natural gas prices may mitigate this effect), and lower consumption of electricity in general (these demand decreases would lead to lower production levels with associated benefits for the environment). The magnitude of these adjustments will be a function of the structure of the CGE model and the elasticities in it that control the ease of these substitutions.

The macroeconomic effects beyond energy production and consumption decisions also depend on the theoretical structure of the CGE model used in the analysis. Similar to the perfect-foresight nature of IPM, CGE models like EMPAX-CGE assume that firms and consumers will observe and anticipate policies to be enacted in the future. This causes them to adjust their behavior and investment decisions in all time periods in the model (including the starting year of the model). As a result, anticipation of changes in production and consumption costs in the future will cause shifts in behavior in all model years as people prepare ahead of policy enactment. The aggregate implications of these changes will also be influenced by income effects (how people will alter consumption levels in response to having more or less money) and substitution effects (how people will alter their patterns of consumption purchases in response to changes in relative prices of goods). For example, an anticipated decrease in labor productivity in the future (leading to lower wages) may cause an increase in work effort today, while labor is more productive. Alternatively, it may lead to a decrease in work effort today because, in part, labor today is used to generate capital goods for tomorrow, which will be used to augment less-productive labor in the future.

For the electricity-generation industry, the methodology used to link IPM and EMPAX-CGE for this BART analysis focuses on BART resource costs and implications for coal use by utilities.[9] IPM estimates of additional resources used by electric utilities (the capital, fixed, and variable costs) are used to adjust generation technologies in EMPAX-CGE. The same procedure is used to account for incremental increases in natural gas purchases by utilities (although all these costs are applied exclusively to natural gas inputs to electricity generation in EMPAX-CGE, rather than being apportioned using the Nestor and Pasurka data). Given that approximately 90 percent of all coal is consumed in generation, we use IPM estimates of changes in coal use directly within EMPAX-CGE, expressed as percentage changes in Btus, rather than adopting a less direct linkage. However, for both coal and natural gas, EMPAX-CGE is allowed to estimate the impacts on commodity prices faced by the rest of the economy. Cost data from AirControlNET are used to adjust the technologies used to manufacture goods in EMPAX-CGE to account for any additional production costs.

A.1.4 Projected Impacts on Specific Industries

Impacts of the BART guidance on manufacturing and electricity-generation costs will affect output and prices of all industries in EMPAX-CGE. These effects may increase or decrease output and/or revenue, depending on their implications for production costs and technologies and shifts in household demands. However, as shown in Figure A-1, estimates for output changes from BART are generally less than 0.05 percent.

Some industries are affected more than others. BART has little impact on electric utilities, with energy-intensive sectors of the economy being relatively more affected than other firms because their costs have risen more than other segments of the economy. However, the largest of these declines in output (paper and allied products) is approximately two-tenths of 1 percent.

[9]See Section A.1.9 for EMPAX-CGE results using other linkages to IPM.

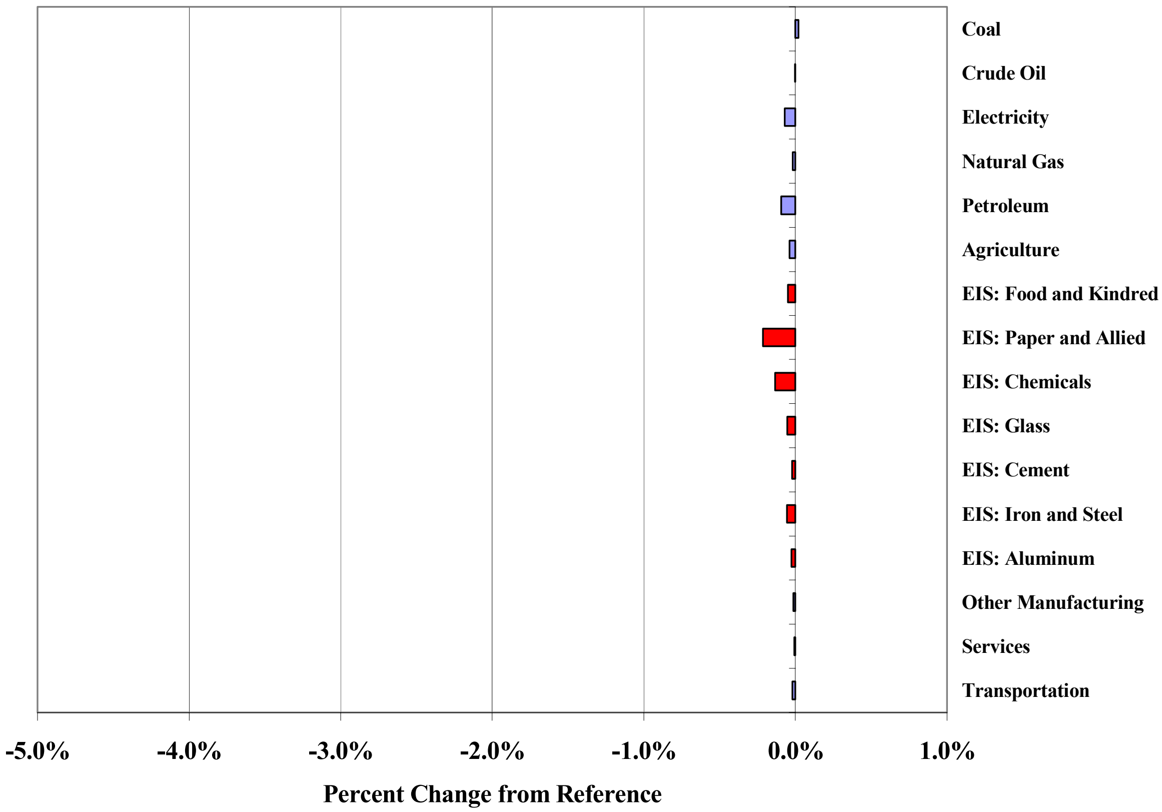

Figure A-1. BART Impacts on U.S. Domestic Output, 2015

Source: EMPAX-CGE (BART Scenario 2)

Regional effects tend to show some variation that does not appear at the national level. Figure A-2 shows these regional results for energy markets and highlights the aggregate U.S. results with a solid bar. The largest differences are in electricity generation because the eastern part of the United States is relatively unaffected by the policy, other than through spillover effects reflected in both IPM and EMPAX-CGE, compared to the western half of the country. Changes in natural gas and coal production are also distributed unevenly across the country.

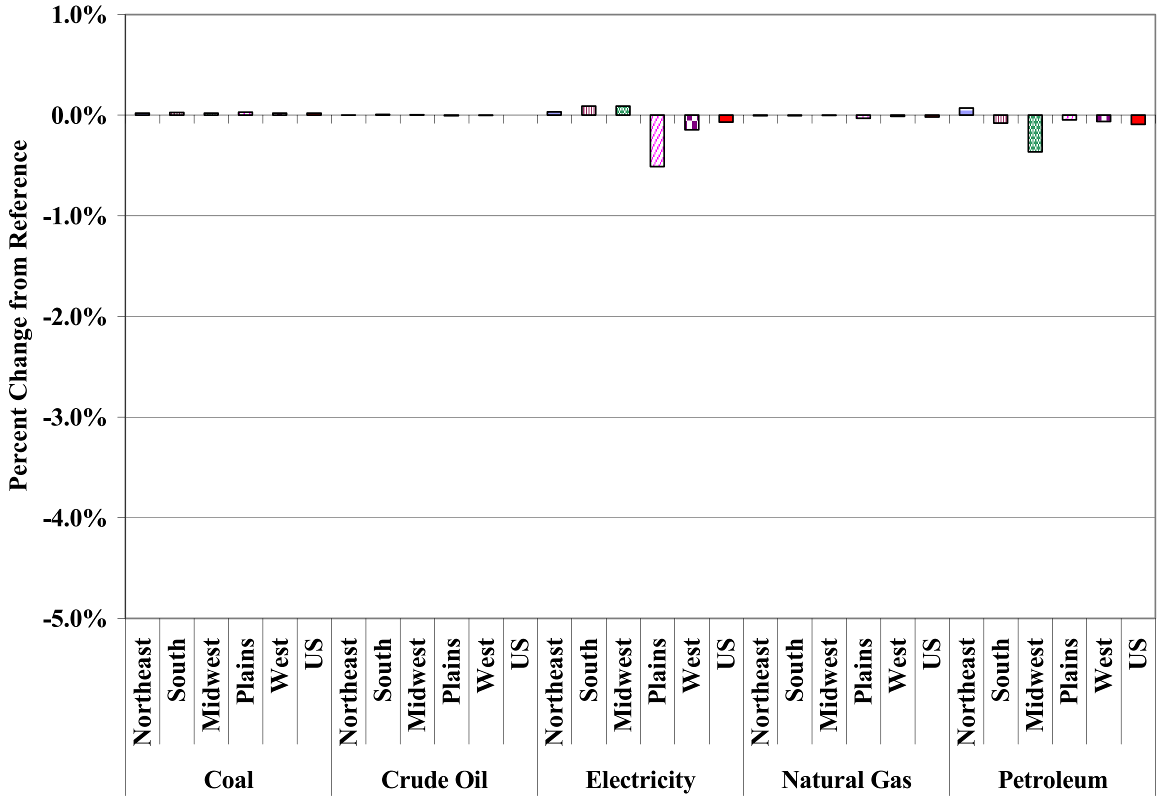

Figure A-2. BART Impacts on Regional Energy Output, 2015

Source: EMPAX-CGE (BART Scenario 2)

Figure A-3 shows regional results for nonenergy industries in EMPAX-CGE.[10] Although these sectors show more regional variation based on differences in production methods and changes in manufacturing costs, the majority of the impacts are less than five one-hundredths of 1 percent. Energy-intensive firms in the Northeast experience a comparative advantage relative to other parts of the country. Impacts on other manufacturing and the services industry are uniformly small, however; given the size of this sector, the effect on total revenue is larger than for all other industries combined.

[10]Results for the seven components of energy-intensive sectors are aggregated in Figure A-3 for presentation purposes, although they are all included simultaneously in the EMPAX-CGE model run.

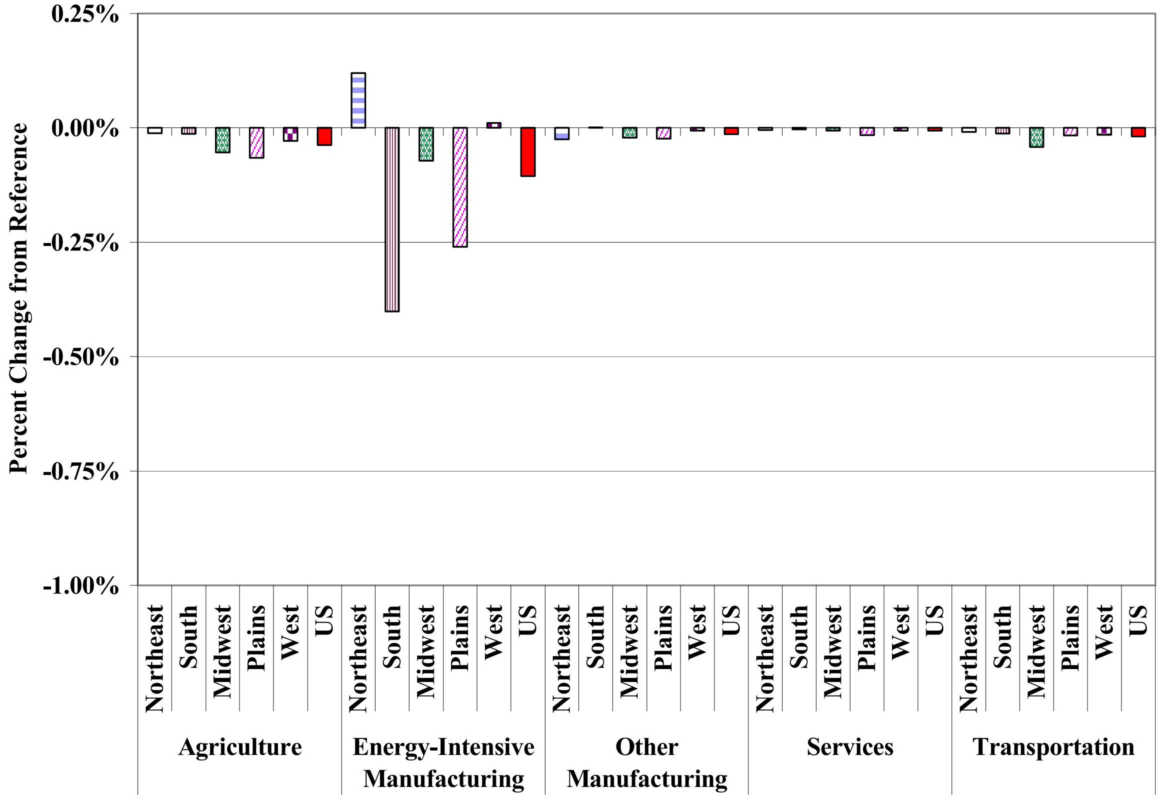

Figure A-3. BART Impacts on Regional Industrial Output, 2015

Source: EMPAX-CGE (BART Scenario 2)

Although the average effect on energy-intensive industries is negative because of increased manufacturing costs, industries in some parts of the United States are estimated to be raising their output. Even though costs have risen slightly, they experience an advantage over similar firms in other regions that face proportionately larger increases. Although the Northeast sees the greatest improvement in comparative advantage, output also rises in some other regions (see Figure A-4). The largest decline is in paper manufacturing in the South.

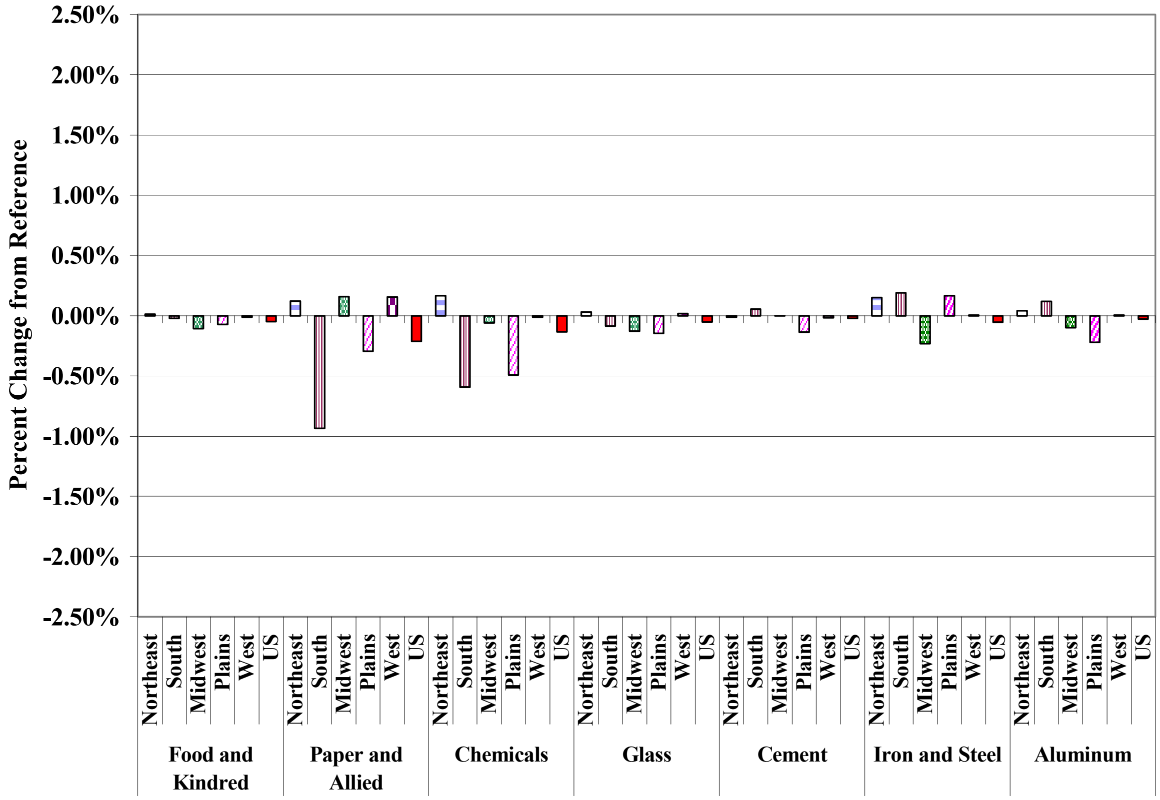

Figure A-4. BART Impacts on Regional Energy-Intensive Output, 2015

Source: EMPAX-CGE (BART Scenario 2)

A.1.5 Projected Impacts on Consumer Prices

Changes in consumer price levels are used to measure price effects of policies and any resulting implications for average purchase prices paid by households. EMPAX-CGE calculates an overall price level across the "basket" of goods and services bought by consumers. For a policy like the BART guidance, consumer price levels will be affected directly by changes in electricity and manufactured-goods prices faced by households and indirectly by changes in goods prices that have been produced using those commodities. Figure A-5 shows that average consumer prices are essentially unchanged.

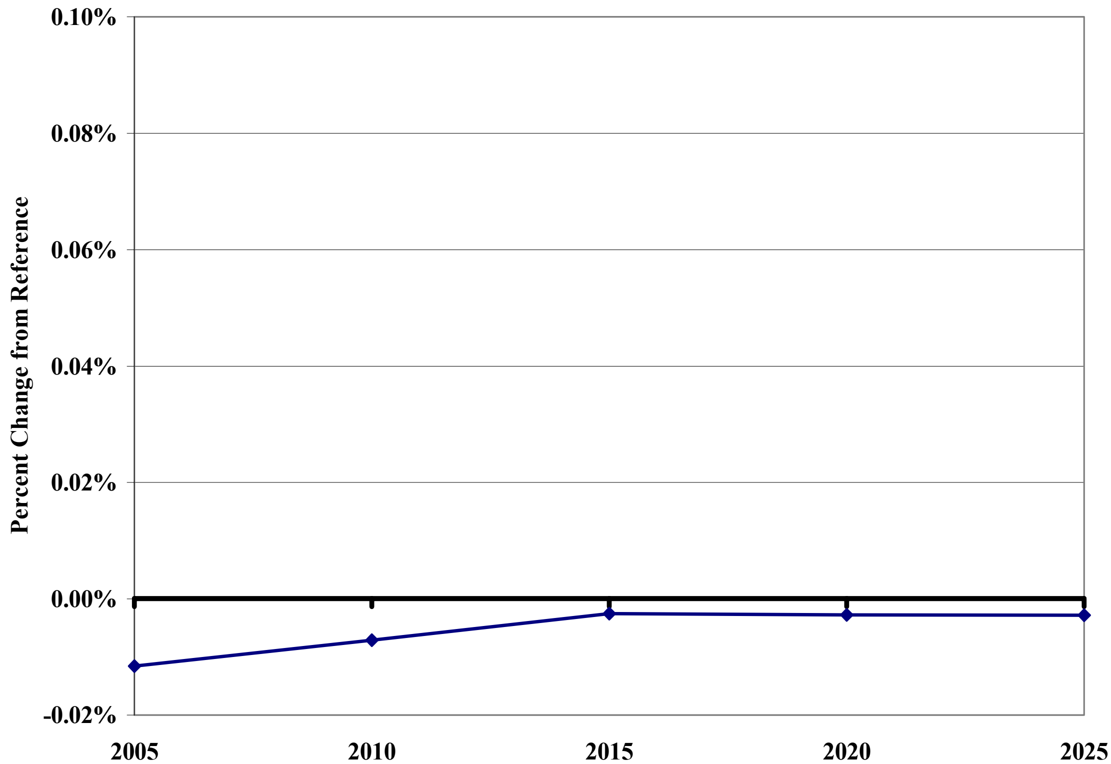

Figure A-5. Change in Consumer Prices Compared to Reference Case

Source: EMPAX-CGE (BART Scenario 2)
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

A.1.6 Projected Impacts on Labor Markets

CGE models like EMPAX-CGE typically consider how policies may influence labor markets through how they alter the number of productivity-adjusted hours of labor supplied by households (this is not the same as estimating jobs or employment). Empirical estimates of labor-supply elasticities are used by EMPAX-CGE to simulate how demands by firms and supply decisions by households are made, along with resulting implications for real wages. EMPAX-CGE is a full-employment model in which households choose between labor and leisure time, based on both income and substitution effects.

Figure A-6 gives EMPAX-CGE's projected impacts of BART on labor markets. The results indicate that people are choosing to work slightly more hours to offset additional costs of purchasing goods. These effects are extremely small, however, on the order of five ten-thousandths of 1 percent.

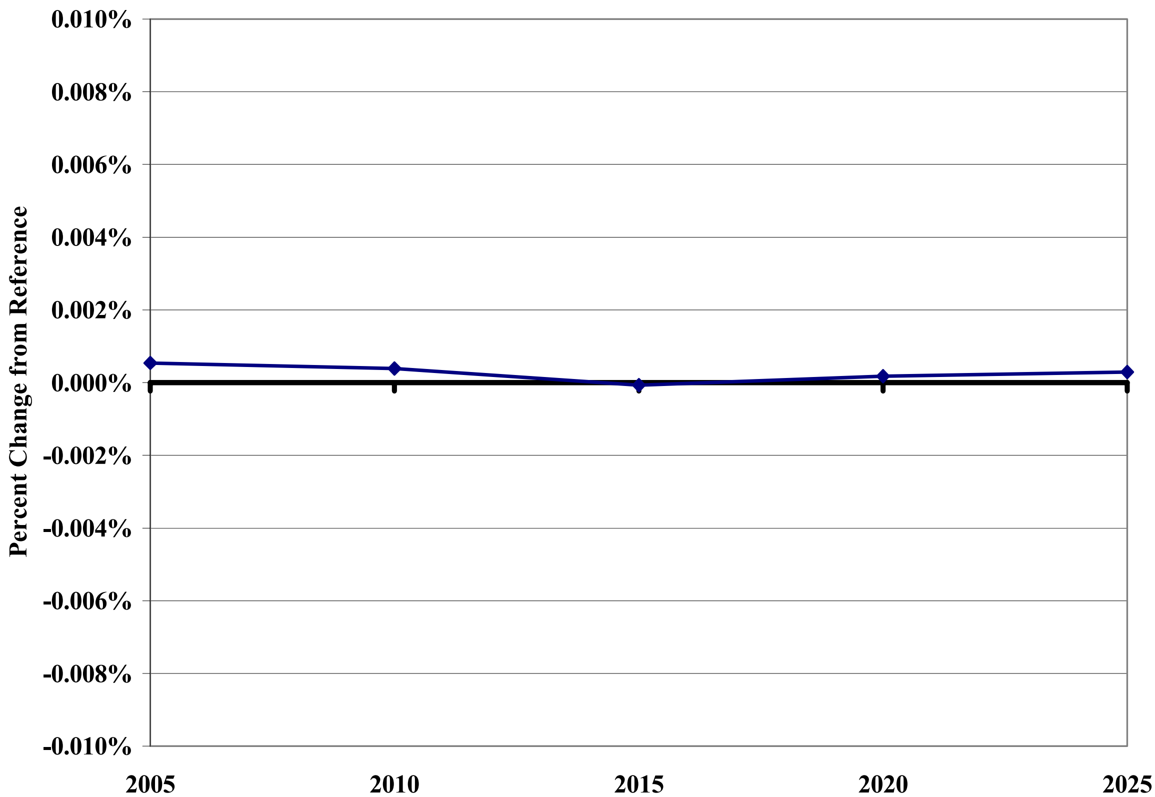

Figure A-6. Change in Labor Inputs Compared to Reference Case

Source: EMPAX-CGE (BART Scenario 2)
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

A.1.7 Projected Impacts on GDP

The combination of all economic interactions as described earlier will be reflected in the changes in GDP estimated by a CGE model. Given that this cost-based approach to analyzing BART does not reflect its benefits to the environment, public health, and labor productivity, CGE models (including EMPAX-CGE) will tend to estimate declines in total production in the United States, as shown in Figure A-7. Because these results are incomplete and do not reflect potential benefits of BART, the impacts on GDP should not be construed as the costs of the guidance. EMPAX-CGE projects decreases in GDP for BART Scenario 2 of between 0.01 percent and 0.02 percent (two one-hundredths of 1 percent).

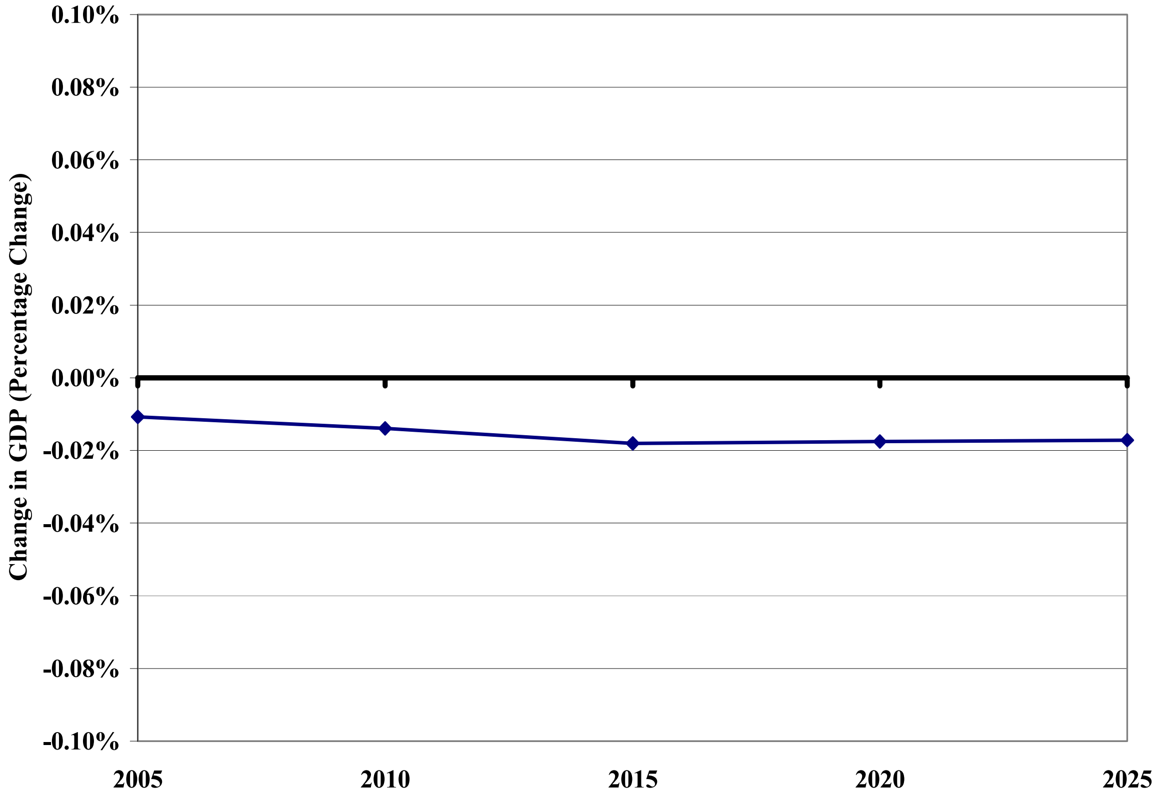

Figure A-7. Change in GDP Compared to Reference Case

Source: EMPAX-CGE (BART Scenario 2)
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

Overall, it should be noted that the estimated implications of the BART guidance for U.S. GDP are extremely small relative to the total size of the economy. Figure A-8 illustrates GDP in the model baseline and BART policy cases. As shown, the GDP impact is negligible and, in fact, it is not possible to adjust the scale of the graph to the point where the two lines do not overlap. Even these small costs could be reversed if the CGE analyses were extended to include benefits associated with BART such as improvements in labor productivity from environmental improvements.

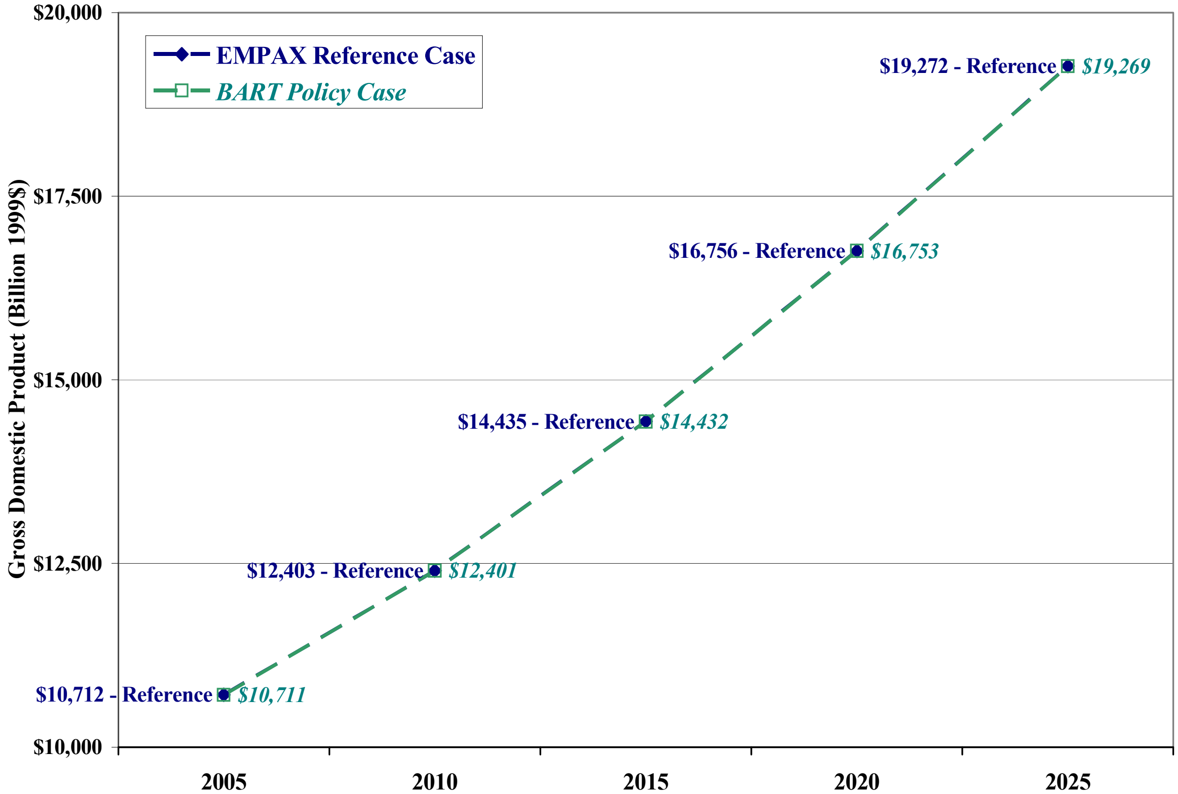

Figure A-8. U.S. Gross Domestic Product (GDP): Reference Case vs. BART

Source: EMPAX-CGE (BART Scenario 2)
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

National GDP effects like those in Figure A-8 may tend to obscure variation at a regional or local level. Several potential sources of divergences in regional impacts exist:

- differences in IPM regional results based on regional mixes of generation technologies (coal, gas, oil, and nonfossil use), which may be averaged out at a national level;
- differences in regional production and consumption patterns for electricity and nonelectricity energy goods;
- differences in industrial composition of regional economies;
- differences in household consumption patterns; and
- differences in regional growth forecasts.

Figure A-9 presents the regional GDP changes estimated by EMPAX-CGE that underlie the national U.S. results above. As with other types of results, northeastern States are relatively unaffected by BART for several reasons: most of the resource costs are experienced by electricity generators in the West, the industrial composition of the West (especially California) tends to lean towards less energy-intensive industries like services, and production patterns for energy-intensive sectors shift towards the West as it experiences an improvement in its comparative advantage in their production. Other parts of the United States, like the South and Plains, have a higher proportion of energy-intensive industries such as paper and chemicals that experience higher impacts and, as a result, have slightly larger relative GDP declines than the U.S. average.

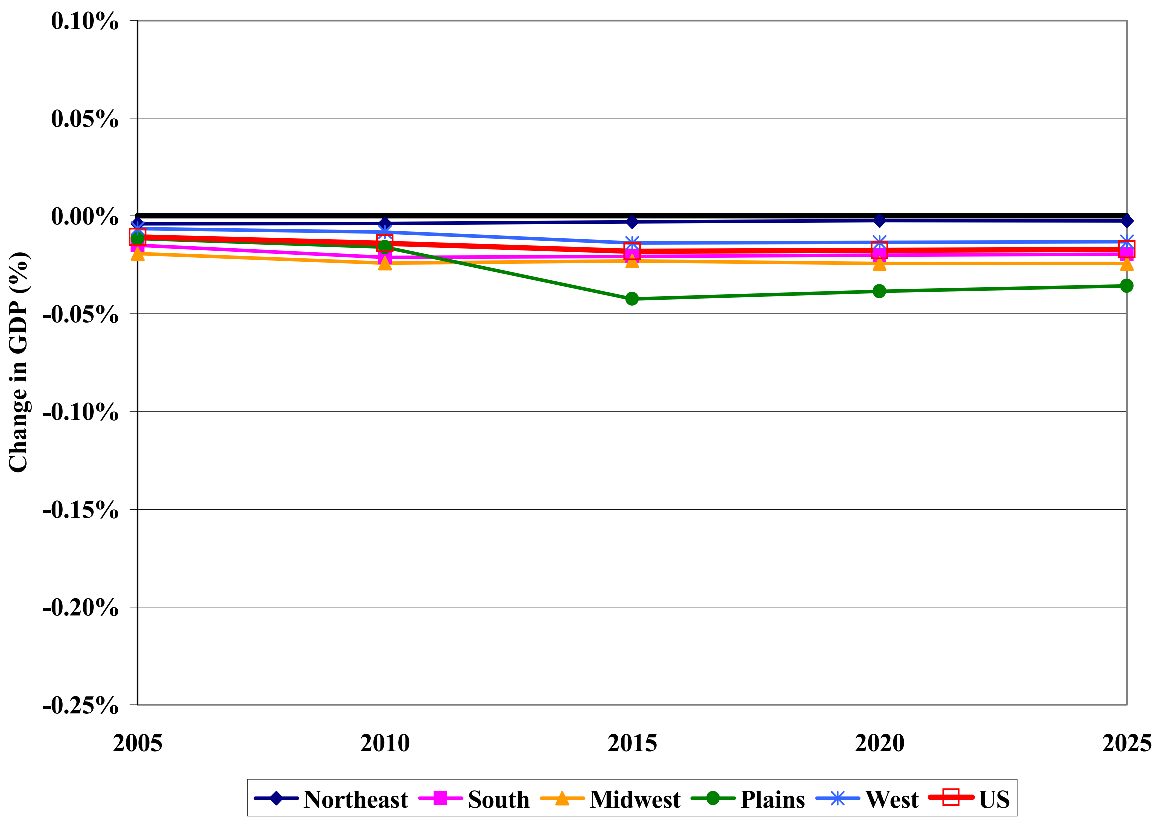

Figure A-9. Change in Regional GDP Compared to Reference Case

Source: EMPAX-CGE (BART Scenario 2)
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

Tables A-1 and A-2 show EMPAX-CGE estimates of changes in revenue and output quantities for 2015 and 2020 for BART Scenario 2.

Table A-1. U.S. Domestic Output Changes

Variable	Industry	2015	2020
Percentage Change in Revenue (%)	Coal	0.07%	0.32%
	Crude Oil	0.00%	0.00%
	Electricity	0.06%	0.05%
	Natural Gas	–0.07%	–0.11%
	Petroleum	–0.03%	–0.03%
	Agriculture	–0.04%	–0.04%
	Energy-Intensive Manufacturing	–0.03%	–0.03%
	Other Manufacturing	–0.01%	–0.01%
	Services	–0.01%	–0.01%
	Transportation	–0.02%	–0.02%
Percentage Change In Quantity (%)	Coal	0.02%	0.10%
	Crude Oil	0.00%	0.00%
	Electricity	–0.07%	–0.03%
	Natural Gas	–0.02%	–0.03%
	Petroleum	–0.09%	–0.09%
	Agriculture	–0.04%	–0.04%
	Energy-Intensive Manufacturing	–0.11%	–0.11%
	Other Manufacturing	–0.01%	–0.01%
	Services	–0.01%	–0.01%
	Transportation	–0.02%	–0.02%

Source: EMPAX-CGE (BART Scenario 2)

Table A-2. U.S. Domestic Energy-Intensive Sector Output Changes

Variable	Industry	2015	2020
Percentage Change in Revenue (%)	Food and Kindred	–0.02%	–0.02%
	Paper and Allied	0.04%	0.03%
	Chemicals	–0.07%	–0.08%
	Glass	–0.02%	–0.03%
	Cement	–0.01%	0.00%
	Iron and Steel	0.01%	0.01%
	Aluminum	0.00%	0.00%
Percentage Change In Quantity (%)	Food and Kindred	–0.05%	–0.05%
	Paper and Allied	–0.21%	–0.22%
	Chemicals	–0.13%	–0.14%
	Glass	–0.05%	–0.05%
	Cement	–0.02%	–0.02%
	Iron and Steel	–0.05%	–0.06%
	Aluminum	–0.03%	–0.03%

Source: EMPAX-CGE (BART Scenario 2)

A.1.8 Alternative BART Scenarios

The preceding results focus on BART Scenario 2. This section compares these results to those for BART Scenarios 1 and 3. Figure A-10 shows how the alternative scenarios affect industrial output. In general, the impacts follow a pattern similar to the stringency of the individual BART scenario. However, all impacts remain uniformly small across the three sets of results.

A comparable pattens also holds for GDP changes across the three alternatives (see Figure A-11). Scenario 2 has the midrange GDP effects with Scenario 1 showing essentially no GDP impacts and Scenario 3 having a decline in GDP of between two and four one-hundredths of 1 percent.

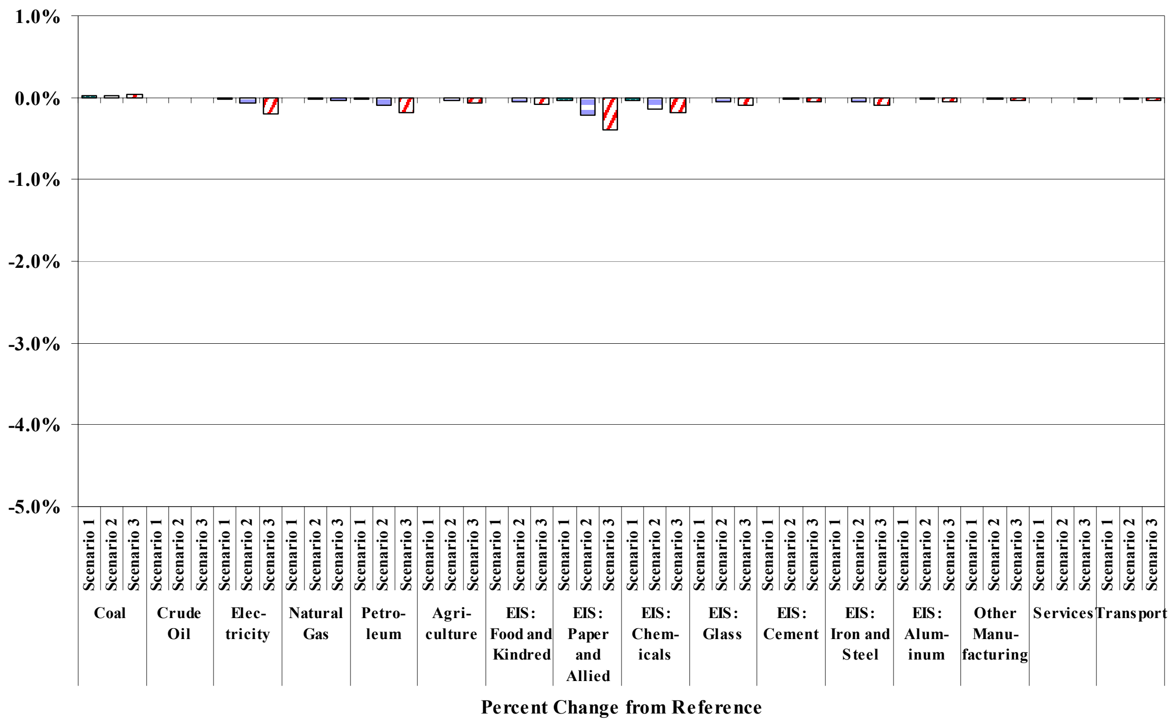

Figure A-10. Domestic Output Impacts of Alternative BART Scenarios

Source: EMPAX-CGE

A.1.9 Alternative IPM-to-EMPAX Linkages

As discussed in Section A.1.2, EMPAX-CGE is capable of incorporating a variety of results from IPM, depending on the desired type of linkage between the two models. This section presents macroeconomic impacts for BART Scenario 2, as shown by changes in GDP, using two alternative methods for linking EMPAX-CGE to the IPM results. These alternative findings are contrasted to this "Central Case" (i.e., the results presented above for Scenario 2) to demonstrate how the methodology used to link the two models can influence results. One alternative linkage, referred to as the "IPM Price & Fuel Case," places a higher degree of reliance on IPM results than the "Central Case." In the other alternative, referred to as the "Unconstrained Case," EMPAX-CGE is allowed to determine more market outcomes than in the "Central Case." These scenarios provide a range of results that illustrate the macroeconomic implications of different methods for linking macroeconomic models with the IPM results.

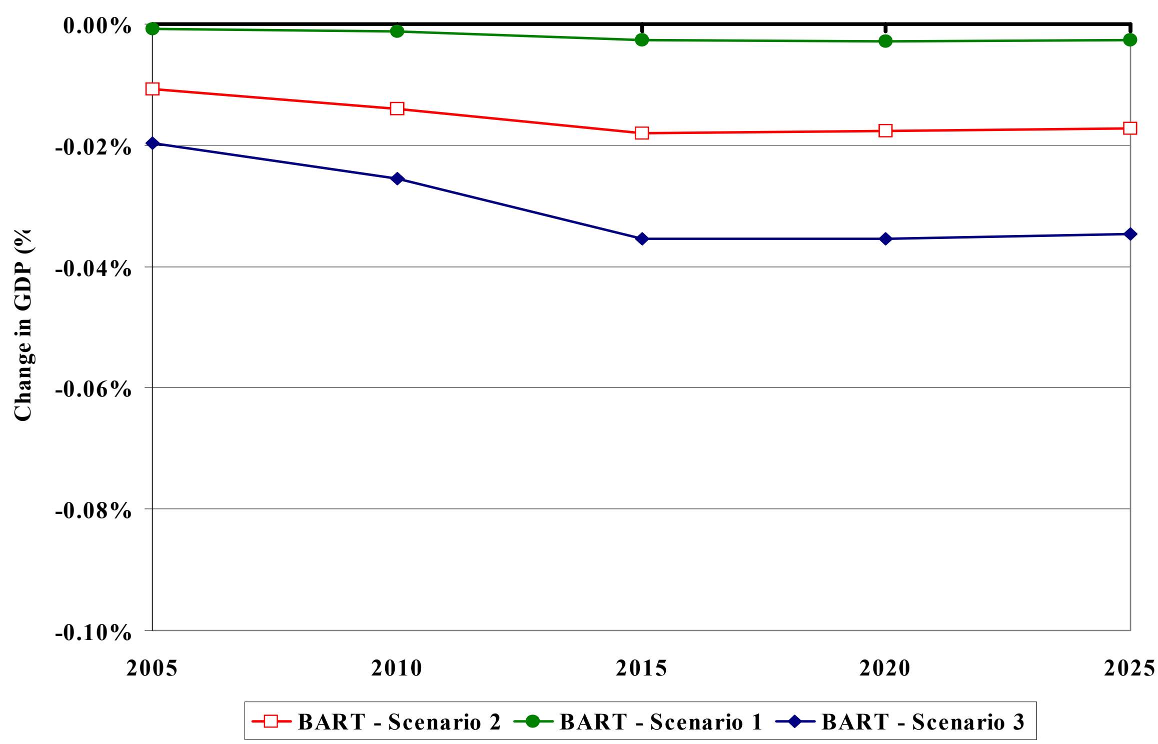

Figure A-11. GDP Impacts of Alternative BART Scenarios

Source: EMPAX-CGE
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

Specifically, the three alternative approaches are as follows:

- ***"Central Case"***—This BART Scenario 2 case from the main analysis incorporates IPM estimates of resource costs (capital costs, and fixed and variable operating costs), along with percentage changes in coal use (expressed in Btus), in EMPAX-CGE. The IPM resource costs are used to adjust electricity generation costs within EMPAX-CGE by requiring additional purchases of capital, labor, and material inputs. Natural gas expenditures are also adjusted based on IPM findings by requiring additional purchases of gas by utilities.
- ***"Unconstrained Case"***—This BART Scenario 2 case incorporates IPM estimates of both resource costs and fuel expenditures for coal and gas into EMPAX-CGE. Unlike the "Central Case," this case allows changes in the quantity of coal use in the electricity sector to be estimated by EMPAX-CGE, once declines in the dollar value of coal purchases from the IPM model have been incorporated into the

model. These declines in coal purchases are integrated using the same methodology applied to the capital, labor, and material inputs needed to generate electricity—in this case, by requiring fewer purchases of coal to produce electricity.

- ***"IPM Price & Fuel Case"***—This BART Scenario 2 case places the most reliance on IPM findings. Rather than allowing EMPAX-CGE to determine electricity price outcomes based on IPM resource costs, it replicates the IPM price results in EMPAX-CGE and concentrates on examining their implications for the rest of the economy. Similarly, this case uses IPM data on changes in coal and gas use (in physical units) by electricity sector instead of allowing the CGE model to make these decisions. Market prices for coal and gas are still determined by EMPAX-CGE. This case takes into consideration the fact that, although most resource costs of electricity policies are borne by coal-fired generation, electricity prices are typically determined by the marginal unit in operation. Because of this, there may not be a direct correlation between policy costs and implications for electricity prices, although the economy outside of the electricity industry will respond to both electricity prices and any effects from drawing additional resources into electricity production.

Figure A-12 illustrates the implications of these alternative linkages between IPM and EMPAX-CGE for estimates of BART GDP effects. The "Central Case" from the main analysis and "Unconstrained Case" follow similar paths; however, the "Unconstrained Case" is uniformly less expensive. It provides more degrees of freedom to adjust coal consumption by utilities in response to demand changes estimated by EMPAX-CGE and also has added flexibility to shift among production inputs. This results in GDP impacts between 10 and 15 percent lower than in the "Central Case."

The "IPM Price & Fuel Case" shows changes in GDP are generally lower than in the "Central Case." The methodologies of these two cases are substantially different: many of the effects in the "IPM Price & Fuel Case" are driven by IPM's estimated changes in electricity prices (and to a lesser degree by impacts on gas prices from increased demand by generators), while in the "Central Case" electricity prices predicted by EMPAX-CGE are controlled by how many additional resource costs are entering electricity production. IPM results show moderate increases in electricity prices in 2015 through 2025, leading to smaller GDP effects in the "IPM Price & Fuel Case" than in the "Central Case."

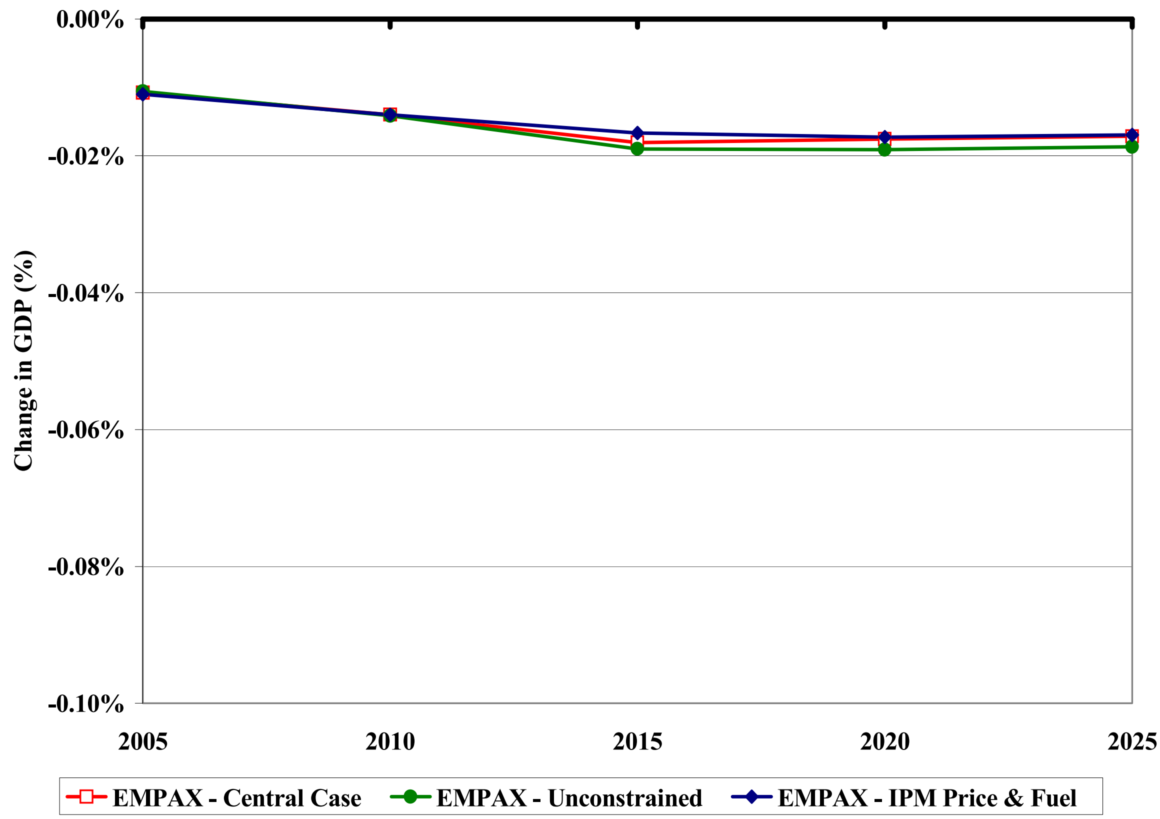

Figure A-12. GDP Impacts of Alternative Linkages (%)

Source: EMPAX-CGE
Note: Changes occur in 2005 as people react to the policy announcement, in anticipation of future effects.

A.2 EMPAX-CGE Model Description: General Model Structure

This section provides additional details on the EMPAX-CGE model structure, data sources, and assumptions. The version of EMPAX-CGE used in this analysis is a dynamic, intertemporally optimizing model that solves in 5-year intervals from 2005 to 2050. It uses the classical Arrow-Debreu general equilibrium framework wherein households maximize utility subject to budget constraints, and firms maximize profits subject to technology constraints. The model structure, in which agents are assumed to have perfect foresight and maximize utility across all time periods, allows agents to modify behavior in anticipation of future policy changes, unlike dynamic recursive models that assume agents do not react until a policy has been implemented.

Nested CES functions are used to portray substitution possibilities available to producers and consumers. Figure A-13 illustrates this general framework and gives a broad characterization of the model.[11] Along with the underlying data, these nesting structures and associated substitution elasticities determine the effects that will be estimated for policies. These nesting structures and elasticities used in EMPAX-CGE are generally based on the Emissions Prediction and Policy Analysis (EPPA) Model developed at the Massachusetts Institute of Technology (Babiker et al., 2001). Although the two models are quite different (EPPA is a recursive-dynamic, international model focused on national-level climate-change policies), both are intended to simulate how agents will respond to environmental policies.

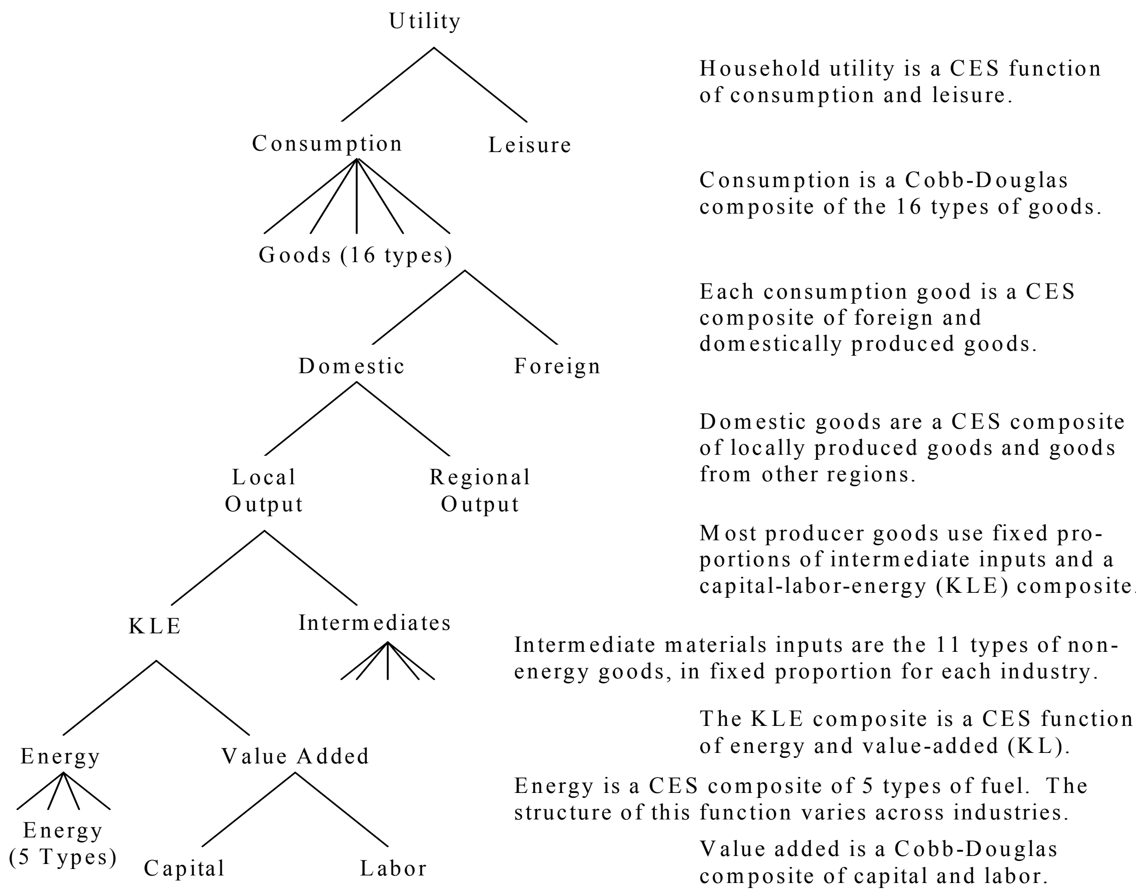

Figure A-13. General Production and Consumption Nesting Structure in EMPAX-CGE

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[11]Although it is not illustrated in Figure A-13, some differences across industries exist in their handling of energy inputs. In addition, the agriculture and fossil-fuel sectors in EMPAX-CGE contain equations that account for the presence of fixed inputs to production (land and fossil-fuel resources, respectively).

Given this basic similarity, EMPAX-CGE has adopted a comparable structure. EMPAX-CGE is programmed in the GAMS[12] language (Generalized Algebraic Modeling System) and solved as a mixed complementarity problem (MCP)[13] using MPSGE software (Mathematical Programming Subsystem for General Equilibrium).[14] The PATH solver from GAMS is used to solve the MCP equations generated by MPSGE.

A.2.1 Data Sources

The economic data come from state-level information provided by the Minnesota IMPLAN Group[15] and energy data come from EIA.[16] Although IMPLAN data contain information on the value of energy production and consumption in dollars, these data are replaced with EIA data for several reasons. First, the policies being investigated typically focus on energy markets, making it essential to include the best possible characterization of these markets in the model. Although the IMPLAN data are developed from a variety of government data sources at the U.S. Bureau of Economic Analysis and U.S. Bureau of Labor Statistics, these data do not always agree with energy information collected by EIA directly from manufacturers and electric utilities. Second, it is necessary to have physical quantities for energy consumption in the model to portray effects of environmental policies. EIA reports physical quantities, while IMPLAN does not. Finally, although the IMPLAN data reflect the year 2000, the initial baseline year for the model is 2005. Thus, AEO energy production and consumption, output, and economic growth forecasts for 2005 are used to adjust the year 2000 IMPLAN data.

EMPAX-CGE combines these economic and energy data to create a balanced social accounting matrix (SAM) that provides a baseline characterization of the economy. The

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[12]See Brooke et al. (1998) for a description of GAMS (http://www.gams.com/).

[13]Solving EMPAX-CGE as an MCP problem implies that complementary slackness is a feature of the equilibrium solution. In other words, any firm in operation will earn zero economic profits, and any unprofitable firms will cease operations. Similarly, for any commodity with a positive price, supply will equal demand, or conversely any good in excess supply will have a zero price.

[14]See Rutherford (1999) for MPSGE documentation (http://debreu.colorado.edu).

[15]See <http://www.implan.com/index.html> for a description of the Minnesota IMPLAN Group (2003) and its data.

[16]These EIA sources include *AEO 2003*, the Manufacturing Energy Consumption Survey, State Energy Data Report, State Energy Price and Expenditure Report, and various annual industry profiles (EIA, 2001; undated[a and b]).

SAM contains data on the value of output in each sector, payments for factors of production and intermediate inputs by each sector, household income and consumption, government purchases, investment, and trade flows. A balanced SAM for the year 2005 consistent with the desired sectoral and regional aggregation is produced using procedures developed by Babiker and Rutherford (1997) and described in Rutherford and Paltsev (2000). The methodology relies on standard optimization techniques to maintain the calculated energy statistics while minimizing the changes needed in the economic data to create a new balanced SAM that matches AEO forecasts for the baseline model year of 2005.

These data are used to define 10 regions within the United States, each containing 40 industries. Regions have been selected to capture important differences across the country in electricity-generation technologies, while industry aggregations are controlled by available energy consumption data. Prior to solving EMPAX-CGE, these regions and industries are aggregated up to the categories to be included in the analysis.

Table A-3 presents the industry categories included in EMPAX-CGE for policy analysis. Their focus is on maintaining as much detail in the energy-intensive sectors[17] as is allowed by available energy consumption data and computational limits of dynamic CGE models. In addition, the electricity industry is separated into fossil-fuel generation and nonfossil generation, which is necessary because many electricity policies affect only fossil-fired electricity.

Figure A-14 shows the five regions used in this analysis, which have been defined based on the expected regional distribution of policy impacts, availability of economic and energy data, and computational limits on model size. These regions have been constructed from the underlying 10-region database designed to follow, as closely as possible, the electricity market regions defined by the North American Electric Reliability Council (NERC).[18]

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[17]Energy-intensive sectors industry categories are based on EIA definitions of energy-intensive manufacturers in the *Assumptions for the Annual Energy Outlook 2003*.

[18]Economic data and information on nonelectricity energy markets are generally available only at the state level, which necessitates an approximation of the NERC regions that follows state boundaries. For policy analyses, these approximations include Northeast = NPCC + MAAC, Southeast = SERC + FERC, Midwest = ECAR + MAIN, Plains = MAPP + SPP + ERCOT, and West = WSCC. See <http://www.nerc.com/> for further discussion of these regions.

Table A-3. EMPAX-CGE Industries

EMPAX Industry	NAICS Classifications
Coal	2121
Crude Oil[a]	211111
Electricity (fossil and nonfossil)	2211
Natural Gas	211112, 2212, 4862
Petroleum Refining	324
Agriculture	11
Energy-Intensive Sector: Food	311
Energy-Intensive Sector: Paper and Allied	322
Energy-Intensive Sector: Chemicals	325
Energy-Intensive Sector: Glass	3272
Energy-Intensive Sector: Cement	3273
Energy-Intensive Sector: Iron and Steel	3311
Energy-Intensive Sector: Aluminum	3313
Other Manufacturing	312-316, 321, 323, 326-327, 331-339
Services	All Others
Transportation[b]	481-488

[a] Although NAICS 211111 covers crude oil and gas extraction, the gas component of this sector is moved to the natural gas industry.

[b] Transportation does not include NAICS 4862 (natural gas distribution), which is part of the natural gas industry.

A.2.2 Production Functions

All productive markets are assumed to be perfectly competitive and have production technologies that exhibit constant returns to scale, except for the agriculture and natural resource extracting sectors, which have decreasing returns to scale because they use factors in fixed supply (land and fossil fuels, respectively). The electricity industry is separated into two distinct sectors: fossil-fuel generation and nonfossil generation. This allows tracking of variables such as heat rates for fossil-fired utilities (Btus of energy input per kilowatt hour of electricity output).

All markets must clear (i.e., supply must equal demand in every sector) in every period, and the income of each agent in the model must equal their factor endowments plus any net transfers. Along with the underlying data, the nesting structures shown in Figure A-13 and associated substitution elasticities define current production technologies and possible alternatives.

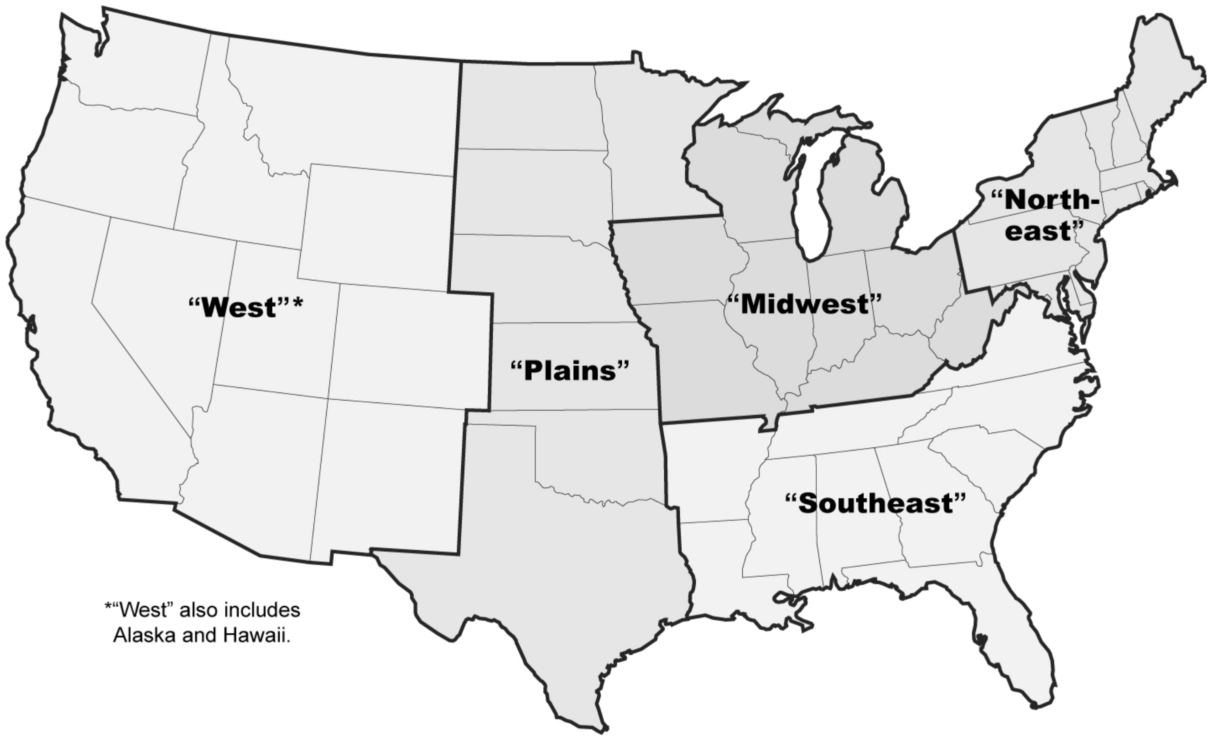

Figure A-14. Regions Defined in EMPAX-CGE for Policy Analysis

A.2.3 Utility Functions

Each region in the dynamic version of EMPAX-CGE contains four representative households, classified by income, that maximize intertemporal utility over all time periods in the model subject to budget constraints, where the income groups are

- \$0 to \$14,999,
- \$15,000 to \$29,999,
- \$30,000 to \$49,999, and
- \$50,000 and above.

These representative households are endowed with factors of production including labor, capital, natural resources, and land inputs to agricultural production. Factor prices are equal to the marginal revenue received by firms from employing an additional unit of labor or capital. The value of factors owned by each representative household depends on factor use implied by production within each region. Income from sales of these productive factors is allocated to purchases of consumption goods to maximize welfare.

Within each time period, intratemporal utility received by a household is formed from consumption of goods and leisure. All consumption goods are combined using a Cobb-Douglas structure to form an aggregate consumption good. This composite good is then combined with leisure time to produce household utility. The elasticity of substitution between consumption goods and leisure depends on empirical estimates of labor-supply elasticities and indicates how willing households are to trade off leisure time for consumption. Over time, households consider the discounted present value of utility received from all periods' consumption of goods and leisure.

Following standard conventions of CGE models, factors of production are assumed to be intersectorally mobile within regions, but migration of productive factors is not allowed across regions. This assumption is necessary to calculate welfare changes for the representative household located in each region in EMPAX-CGE. EMPAX-CGE also assumes that ownership of natural resources and capital embodied in nonfossil electricity generation is spread across the United States through capital markets.

A.2.4 Trade

In EMPAX-CGE, all goods and services are assumed to be composite, differentiated "Armington" goods made up of locally manufactured commodities and imported goods. Output of local industries is initially separated into output destined for local consumption by producers or households and output destined for export. This local output is then combined with goods from other regions in the United States using Armington-trade elasticities that indicate agents make relatively little distinction between output from firms located within their region and output from firms in other regions within the United States. Finally, the domestic composite goods are aggregated with imports from foreign sources using lower trade elasticities to capture the fact that foreign imports are more differentiated from domestic output than are imports from other regional suppliers in the United States.

A.2.5 Tax Rates and Distortions

Taxes and associated distortions in economic behavior have been included in EMPAX-CGE because theoretical and empirical literature found that taxes can substantially alter estimated policy costs. The IMPLAN economic database used by EMPAX-CGE includes information on taxes such as indirect business taxes (all sales and excise taxes) and social security taxes. However, IMPLAN reports factor payments for labor and capital at their gross-of-tax values, which necessitates use of additional data sources to determine personal income and capital tax rates. Information from the TAXSIM model at the National Bureau of Economic Research (Feenberg and Coutts, 1993), along with user-cost-of-capital calculations from Fullerton and Rogers (1993), are used to establish tax rates.

Along with these rates, distortions associated with taxes are a function of labor supply decisions of households. As with other CGE models focused on interactions between tax and environmental policies (e.g., Bovenberg and Goulder [1996]; Goulder and Williams [2003]), an important feature of EMPAX-CGE is its inclusion of a labor-leisure choice—how people decide between working and leisure time. Labor supply elasticities related to this choice determine, to a large extent, how distortionary taxes are in a CGE model. Elasticities based on the relevant literature have been included in EMPAX-CGE (i.e., 0.4 for the compensated labor supply elasticity and 0.15 for the uncompensated labor supply elasticity). These elasticity values give an overall marginal excess burden associated with the existing tax structure of approximately 0.3.

A.2.6 Intertemporal Dynamics and Economic Growth

There are four sources of economic growth in EMPAX-CGE: technological change from improvements in energy efficiency, growth in the available labor supply (from both population growth and changes in labor productivity), increases in stocks of natural resources, and capital accumulation. Energy consumption per unit of output tends to decline over time because of improvements in production technologies and energy conservation. These changes in energy use per unit of output are modeled as AEEIs, which are used to replicate energy consumption forecasts by industry and fuel from EIA.[19] The AEEI values provide the means for matching expected trends in energy consumption that have been taken from the AEO forecasts. They alter the amount of energy needed to produce a given quantity of output by incorporating improvements in energy efficiency and conservation. Labor force and regional economic growth, electricity generation, changes in available natural resources, and resource prices are also based on the AEO forecasts.

Savings provide the basis for capital formation and are motivated through people's expectations about future needs for capital. Savings and investment decisions made by households determine aggregate capital stocks in EMPAX-CGE. The IMPLAN dataset

[19]See Babiker et al. (2001) for a discussion of how this methodology was used in the EPPA model (EPPA assumes that AEEI parameters are the same across all industries in a country, while AEEI values in EMPAX-CGE are industry specific).

provides details on the types of goods and services used to produce the investment goods underlying each region's capital stocks. Adjustment dynamics associated with formation of capital are controlled by using quadratic adjustment costs experienced when installing new capital, which imply that real costs are experienced to build and install new capital equipment.

Prior to investigating policy scenarios, it is necessary to establish a baseline path for the economy that incorporates economic growth and technology changes that are expected to occur in the absence of the policy actions. Beginning from the initial balanced SAM dataset, a "steady-state" growth path is first specified for the economy to ensure that the model remains in equilibrium in future years.[20] Once the model is able to replicate a steady-state growth path, the assumption of a constant growth rate is replaced by actual forecasts from AEO. After incorporating these forecasts, EMPAX-CGE is solved to generate a baseline consistent with them through 2025. Once this baseline is established, it is possible to run "counterfactual" policy experiments.

A.3 References

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[20] A steady-state growth path requires all variables in the model to grow at a constant rate over time, including labor, output, inputs to production, and consumption. If the model has been properly specified, the steady-state replication check will show that the economy remains in equilibrium in each year along this path.

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APPENDIX B

COST AND ECONOMIC IMPACT SUPPLEMENTAL INFORMATION AND SENSITIVITY ANALYSES

This appendix presents supplemental information concerning the cost and economic impact analyses conducted for BART. Section B.1 presents a memo containing a list of BART EGUs potentially affected by the rule, and Section B.2 contains a list of BART EGUs used in the modeling of control scenarios for this RIA. Section B.3 presents a number of non-EGU cost and economic impact sensitivity analyses.

B.1 List of EGU Units Potentially Affected by BART

Memo From Perrin Quarles Associates, Inc.
Re: Follow-Up on Units Potentially Affected by BART
July 19, 2004

Perrin Quarles Associates, Inc.
675 Peter Jefferson Parkway, Suite 200
Charlottesville, Virginia 22911
Voice: (434) 979-3700 • Fax: (434) 296-2860
Email: pqa@pqa.com

<u>MEMORANDUM</u>

TO: Roman Kramarchuk

FROM: Doran Stegura

RE: Follow-Up on Units Potentially Affected by BART

DATE: July 19, 2004

On March 24, 2003, PQA delivered an analysis of sources that may be subject to controls under EPA's Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations. This analysis provided a list of BART units, additional information on the location and control technologies for each unit, and control cost information. The March 2003 analysis only focused on the units for which construction was started by August 7, 1977 and that were not in operation prior to August 7, 1962. Based on EPA guidance, the original analysis also assumed that BART-eligible units are only those that are located at a plant where the total capacity of all units within the BART timeframe exceeds 750 MW.

This follow-up analysis provided additional information on units that are below the 750 MW threshold, but that are potentially within the specified BART timeframe. The approach and assumptions used to identify whether units below the 750 MW threshold could potentially be BART-eligible are consistent with the March 2003 analysis. The units that required additional follow-up research in this regard are those with an online date on or after 1979 since the BART rule could apply if construction on these units commenced prior to August 7, 1977. It was assumed that units with a 1977 or 1978 online date started construction prior to the 1977 cutoff and thus, are considered to be within the BART timeframe. Hunter, unit 1 (UT) is the only exception since it has a PSD permit with an online date of 1978. For the units in question, PQA reviewed the RACT/BACT/LAER Clearinghouse and other internet search information and contacted the appropriate state environmental agencies to verify when the construction permit was issued. Note that the date the construction permit was issued is used as an indication of when construction began for purposes of this analysis. However, actual construction on these units may have started well after the date the permit was issued.

In evaluating the list of units below the 750 MW threshold and with an online date in 1979 or later, PQA assumed that: (1) units subject to Part 60, Subpart D cannot be excluded because this NSPS subpart applies to sources that have started construction after August 17, 1971; (2) units subject to NSPS Subpart Da requirements are outside the applicable BART time period since these requirements apply to sources that started construction after September 18, 1978; and (3) units that received a PSD permit (with a BACT requirement) are outside the BART time period. If a PSD permit was issued, PQA researched the issue date in order to confirm that the unit is outside the BART time period.

Using the above assumptions, a list of 61 units was compiled that required follow-up with the state environmental agency to confirm whether construction began prior to August 7, 1977. Of these 61 units, 43 are located in states covered under the Clean Air InterState Rule (CAIR) and 18 are located in states not covered under CAIR. Per EPA guidance, initial priority was given to those units not located in a state affected by CAIR. Follow-up with the state environmental agencies revealed that of the 61 units that required follow-up, 24 units are within the BART time period, 24 units are outside the BART time period, and 13 units require further follow-up since the state environmental agency was not able to provide the information needed to determine whether the unit started construction prior to August 7, 1977.

Table B-1 summarizes the 61 units analyzed by PQA. The table provides an indication of whether the unit is located in a state affected by CAIR, whether the unit has been identified as within the BART timeframe, and whether additional follow-up with the state agency for information on construction permit dates is required to determine BART eligibility.

Table B-1. Potential BART Units Identified for Follow-Up Analysis

State	Plant Name	ORIS Code	Unit ID	Online	NSPS	CAIR	In BART Timeframe?	Follow-Up Needed	Nameplate (MW)
AL	Charles R Lowman	56	2	1979	D	X	X		233
AL	Charles R Lowman	56	3	1980	D	X	X		233
AZ	Apache Station	160	2	1979	D		X		194.7
AZ	Apache Station	160	3	1979	D		X		194.7
AZ	Springerville	8223	1	1985	D				397
AZ	Springerville	8223	2	1990	D				397
CO	Pawnee	6248	1	1981	D			X	500
CO	Ray D Nixon	8219	1	1980	D		X		207
DE	Indian River	594	4	1980	D	X	X		442.4
FL	C D McIntosh	676	3	1982	D	X			334
FL	Deerhaven	663	B2	1981	D	X			250.75
GA	McIntosh (6124)	6124	1	1979	PRE	X	X		177.66
IA	Ames	1122	8	1982	D	X			65
IA	George Neal South	7343	4	1979	D	X	X		639.9
IA	Louisa	6664	101	1983	D	X			738.09
IA	Ottumwa	6254	1	1981	D	X	X		726
IN	A B Brown Generating Station	6137	1	1979	D	X	X		265.23
KS	Nearman Creek	6064	N1	1981	D	X	X		261
KY	East Bend	6018	2	1981	D	X		X	669.28
KY	R D Green	6639	G1	1979	D	X		X	263.7
KY	R D Green	6639	G2	1981	D	X		X	263.7
KY	Trimble County	6071	1	1990	D	X		X	566.1
LA	Dolet Hills	51	1	1986	D	X			720.75
LA	R S Nelson	1393	6	1982	D	X	X		614.6
LA	Rodemacher	6190	2	1982	D	X	X		558
MD	Brandon Shores	602	1	1984	D	X	X		685.08
MD	Brandon Shores	602	2	1991	D	X	X		685.08
MI	Presque Isle	1769	9	1979	D	X	X		90
MI	Wyandotte	1866	7	1982	D	X			73
MN	Clay Boswell	1893	4	1980	D	X	X		558

(continued)

Table B-1. Potential BART Units Identified for Follow-Up Analysis (continued)

State	Plant Name	ORIS Code	Unit ID	Online	NSPS	CAIR	In BART Timeframe?	Follow-Up Needed	Nameplate (MW)
MO	Iatan	6065	1	1980	D	X	X		725.85
MO	Sikeston	6768	1	1981	D	X	X		261
NC	Elizabethtown Power	10380	UNIT1	1985	D	X			35
NC	Elizabethtown Power	10380	UNIT2	1985	D	X			35
NC	Lumberton Power	10382	UNIT1	1985	D	X			35
NC	Lumberton Power	10382	UNIT2	1985	D	X			35
NC	Mayo	6250	1A	1983	D	X			735.84
NC	Mayo	6250	1B	1983	D	X			735.84
ND	Antelope Valley	6469	B1	1984	D				435
ND	Antelope Valley	6469	B2	1986	D				435
ND	Coyote	8222	B1	1981	D				450
NE	Gerald Whelan Energy Center	60	1	1981	D				76.3
NE	Nebraska City	6096	1	1979	D		X		615.87
NE	Platte	59	1	1982	D				109.8
NV	North Valmy	8224	1	1981	D			X	254.26
OH	Killen Station	6031	2	1982	D	X	X		666.45
OK	Grand River Dam Authority	165	1	1982	D				490
OK	Hugo	6772	1	1982	D				400
OR	Boardman	6106	1SG	1980	D		X		560.5
TX	Coleto Creek	6178	1	1980	D	X	X		600.39
TX	Gibbons Creek	6136	1	1983	D	X			443.97
TX	Pirkey	7902	1	1985	D	X			720.75
TX	San Miguel	6183	SM-1	1982	D	X			410
TX	Sandow	6648	4	1981	D	X	X		590.64
UT	Hunter (Emery)	6165	1	1978	D			X	446.4
UT	Hunter (Emery)	6165	2	1980	D			X	446.4
WI	Edgewater (4050)	4050	5	1985	D	X		X	380
WI	J P Madgett	4271	B1	1979	D	X		X	387
WI	Pleasant Prairie	6170	1	1980	D	X		X	616.59
WI	Pleasant Prairie	6170	2	1985	D	X		X	616.59
WI	Weston	4078	3	1981	D	X		X	350.46

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B.2 EGU Units Presumed to be BART-Eligible for Purposes of Modeling Emissions

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
AL	Barry	4	1969	404
AL	Barry	5	1971	789
AL	Charles R Lowman	1	1969	66
AL	Charles R Lowman	2	1979	233
AL	Charles R Lowman	3	1980	233
AL	Colbert	5	1965	550
AL	E C Gaston	5	1974	952
AL	Gorgas	10	1972	789
AL	Greene County	1	1965	299
AL	Greene County	2	1966	269
AL	James H Miller Jr	1	1978	706
AL	James H Miller Jr	2	1985	706
AL	Widows Creek	8	1965	550
AR	Flint Creek	1	1978	558
AR	Independence	1	1983	850
AR	White Bluff	1	1980	850
AR	White Bluff	2	1981	850
AZ	Apache Station	2	1979	195
AZ	Apache Station	3	1979	195
AZ	Cholla	2	1978	289
AZ	Cholla	3	1980	289
AZ	Cholla	4	1981	414
AZ	Coronado Generating Station	U1B	1979	411
AZ	Coronado Generating Station	U2B	1980	411
AZ	Irvington	4	1967	173
AZ	Navajo Generating Station	1	1974	803
AZ	Navajo Generating Station	2	1975	803
AZ	Navajo Generating Station	3	1976	803
CO	Cherokee	3	1962	150
CO	Cherokee	4	1968	350
CO	Comanche (470)	1	1973	350

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
CO	Comanche (470)	2	1975	350
CO	Craig	C1	1980	446
CO	Craig	C2	1979	446
CO	Hayden	H1	1965	190
CO	Hayden	H2	1976	275
CO	Martin Drake	5	1962	50
CO	Martin Drake	6	1968	75
CO	Martin Drake	7	1974	132
CO	Pawnee	1	1981	500
CO	Ray D Nixon	1	1980	207
CO	Valmont	5	1964	166
CT	Bridgeport Harbor Station	BHB3	1968	400
DE	Edge Moor	4	1966	177
DE	Indian River	3	1970	177
DE	Indian River	4	1980	442
FL	Big Bend	BB01	1970	446
FL	Big Bend	BB02	1973	446
FL	Big Bend	BB03	1976	446
FL	Crist Electric Generating Plant	6	1970	370
FL	Crist Electric Generating Plant	7	1973	578
FL	Crystal River	1	1966	441
FL	Crystal River	2	1969	524
FL	Crystal River	4	1982	739
FL	Crystal River	5	1984	739
FL	F J Gannon	GB04	1963	187
FL	F J Gannon	GB05	1965	239
FL	F J Gannon	GB06	1967	414
FL	Lansing Smith	1	1965	150
FL	Lansing Smith	2	1967	190
GA	Bowen	1BLR	1971	700
GA	Bowen	2BLR	1972	700
GA	Bowen	3BLR	1974	880

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
GA	Bowen	4BLR	1975	880
GA	Hammond	4	1970	500
GA	Harllee Branch	1	1965	250
GA	Harllee Branch	2	1967	319
GA	Harllee Branch	3	1968	481
GA	Harllee Branch	4	1969	490
GA	Jack McDonough	MB1	1963	245
GA	Jack McDonough	MB2	1964	245
GA	Kraft	3	1965	104
GA	McIntosh (6124)	1	1979	178
GA	Mitchell	3	1964	125
GA	Scherer	1	1982	818
GA	Scherer	2	1984	818
GA	Wansley (6052)	1	1976	865
GA	Wansley (6052)	2	1978	865
GA	Yates	Y6BR	1974	350
GA	Yates	Y7BR	1974	350
IA	Ames	7	1968	33
IA	Burlington (IA)	1	1968	212
IA	Council Bluffs	3	1978	726
IA	Fair Station	2	1967	38
IA	George Neal North	1	1964	147
IA	George Neal North	2	1972	349
IA	George Neal North	3	1975	550
IA	George Neal South	4	1979	640
IA	Lansing	4	1977	275
IA	Milton L Kapp	2	1967	218
IA	Muscatine	8	1969	75
IA	Ottumwa	1	1981	726
IA	Pella	6	1963	38
IA	Pella	7	1973	38
IA	Prairie Creek	4	1967	149

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
IA	Sixth Street	2	1970	85
IA	Sixth Street	4	1970	85
IA	Streeter Station	7	1973	35
IL	Baldwin	1	1970	623
IL	Baldwin	2	1973	635
IL	Baldwin	3	1975	635
IL	Coffeen	01	1965	389
IL	Coffeen	02	1972	617
IL	Dallman	31	1968	90
IL	Dallman	32	1972	90
IL	Dallman	33	1978	207
IL	Duck Creek	1	1976	441
IL	E D Edwards	2	1968	281
IL	E D Edwards	3	1972	364
IL	Havana	9	1978	488
IL	Joliet 29	71	1965	660
IL	Joliet 29	72	1965	660
IL	Joliet 29	81	1965	660
IL	Joliet 29	82	1965	660
IL	Kincaid	1	1967	660
IL	Kincaid	2	1968	660
IL	Lakeside	7	1965	38
IL	Lakeside	8	1965	38
IL	Marion	1	1963	33
IL	Marion	2	1963	33
IL	Marion	3	1963	33
IL	Marion	4	1978	173
IL	Newton	1	1977	617
IL	Newton	2	1982	617
IL	Powerton	51	1972	893
IL	Powerton	52	1972	893
IL	Powerton	61	1975	893

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
IL	Powerton	62	1975	893
IL	Waukegan	8	1962	355
IL	Will County	4	1963	598
IL	Wood River	5	1964	388
IN	A B Brown Generating Station	1	1979	265
IN	Bailly	7	1962	194
IN	Bailly	8	1968	422
IN	Cayuga	1	1970	531
IN	Cayuga	2	1972	531
IN	Dean H Mitchell	11	1970	115
IN	F B Culley Generating Station	2	1966	104
IN	F B Culley Generating Station	3	1973	265
IN	Frank E Ratts	1SG1	1970	117
IN	Frank E Ratts	2SG1	1970	117
IN	Gibson	1	1976	668
IN	Gibson	2	1975	668
IN	Gibson	3	1978	668
IN	Gibson	4	1979	668
IN	Harding Street Station (EW Stout)	70	1973	471
IN	Merom	1SG1	1983	540
IN	Merom	2SG1	1982	540
IN	Michigan City	12	1974	540
IN	Petersburg	1	1967	253
IN	Petersburg	2	1969	471
IN	Petersburg	3	1977	574
IN	R M Schahfer	14	1976	540
IN	R M Schahfer	15	1979	556
IN	State Line Generating Station (IN)	4	1962	389
IN	Tanners Creek	U4	1964	580
IN	Wabash River	6	1968	387
IN	Warrick	2	1964	144
IN	Warrick	3	1965	144

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
IN	Warrick	4	1970	323
IN	Whitewater Valley	2	1973	60
KS	Jeffrey Energy Center	1	1978	720
KS	Jeffrey Energy Center	2	1980	720
KS	La Cygne	1	1973	893
KS	La Cygne	2	1977	685
KS	Lawrence Energy Center	5	1971	458
KS	Nearman Creek	N1	1981	261
KS	Quindaro	1	1965	82
KS	Quindaro	2	1971	158
KS	Tecumseh Energy Center	10	1962	176
KY	Big Sandy	BSU1	1963	281
KY	Big Sandy	BSU2	1969	816
KY	Cane Run	4	1962	163
KY	Cane Run	5	1966	209
KY	Cane Run	6	1969	272
KY	Coleman	C1	1969	174
KY	Coleman	C2	1970	174
KY	Coleman	C3	1971	173
KY	Cooper	1	1965	100
KY	Cooper	2	1969	221
KY	E W Brown	2	1963	180
KY	E W Brown	3	1971	446
KY	East Bend	2	1981	669
KY	Elmer Smith	1	1964	151
KY	Elmer Smith	2	1974	265
KY	Ghent	1	1974	557
KY	Ghent	2	1977	556
KY	H L Spurlock	1	1977	305
KY	H L Spurlock	2	1981	508
KY	Henderson I	6	1968	32
KY	HMP&L Station 2	H1	1973	180

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
KY	HMP&L Station 2	H2	1974	185
KY	Mill Creek	1	1972	356
KY	Mill Creek	2	1974	356
KY	Mill Creek	3	1978	463
KY	Mill Creek	4	1982	544
KY	Paradise	1	1963	704
KY	Paradise	2	1963	704
KY	Paradise	3	1970	1150
KY	R D Green	G1	1979	264
KY	R D Green	G2	1981	264
KY	Robert Reid	R1	1965	82
KY	Trimble County	1	1990	566
LA	Big Cajun 2	2B1	1980	559
LA	Big Cajun 2	2B2	1981	559
LA	R S Nelson	6	1982	615
LA	Rodemacher	2	1982	558
MA	Brayton Point	1	1963	241
MA	Brayton Point	2	1964	241
MA	Brayton Point	3	1969	643
MD	Brandon Shores	1	1984	685
MD	Brandon Shores	2	1991	685
MD	C P Crane	2	1963	209
MD	Chalk Point	1	1964	364
MD	Chalk Point	2	1965	364
MD	Dickerson	3	1962	196
MD	Herbert a Wagner	3	1966	359
MD	Morgantown	1	1970	626
MD	Morgantown	2	1971	626
MI	Belle River	1	1984	698
MI	Belle River	2	1985	698
MI	Eckert Station	4	1964	80
MI	Eckert Station	5	1968	80

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
MI	Eckert Station	6	1970	80
MI	Erickson	1	1973	155
MI	Harbor Beach	1	1968	121
MI	J H Campbell	1	1962	265
MI	J H Campbell	2	1967	385
MI	J H Campbell	3	1980	871
MI	James De Young	5	1969	29
MI	Monroe	1	1971	817
MI	Monroe	2	1973	823
MI	Monroe	3	1973	823
MI	Monroe	4	1974	817
MI	Presque Isle	2	1962	38
MI	Presque Isle	3	1964	54
MI	Presque Isle	4	1966	58
MI	Presque Isle	5	1974	90
MI	Presque Isle	6	1975	90
MI	Presque Isle	7	1978	90
MI	Presque Isle	8	1978	90
MI	Presque Isle	9	1979	90
MI	St. Clair	7	1969	545
MI	Trenton Channel	9A	1968	536
MN	Allen S King	1	1968	598
MN	Clay Boswell	3	1973	365
MN	Clay Boswell	4	1980	558
MN	Hoot Lake	3	1964	75
MN	Northeast Station	NEPP	1971	32
MN	Riverside (1927)	8	1964	239
MN	Sherburne County	1	1976	660
MN	Sherburne County	2	1977	660
MN	Silver Lake	4	1969	54
MO	Asbury	1	1970	232
MO	Blue Valley	3	1965	58

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
MO	Columbia	7	1965	74
MO	Iatan	1	1980	726
MO	James River	4	1964	60
MO	James River	5	1970	105
MO	Labadie	1	1970	574
MO	Labadie	2	1971	574
MO	Labadie	3	1972	621
MO	Labadie	4	1973	621
MO	Lake Road	6	1970	90
MO	Montrose	3	1964	188
MO	New Madrid	1	1972	600
MO	New Madrid	2	1977	600
MO	Rush Island	1	1976	621
MO	Rush Island	2	1977	621
MO	Sibley	2	1962	50
MO	Sibley	3	1969	419
MO	Sikeston	1	1981	261
MO	Sioux	1	1967	550
MO	Sioux	2	1968	550
MO	Southwest	1	1976	194
MO	Thomas Hill	MB1	1966	180
MO	Thomas Hill	MB2	1969	285
MS	Daniel Electric Generating Plant	1	1977	500
MS	Daniel Electric Generating Plant	2	1981	500
MS	R D Morrow	1	1978	200
MS	R D Morrow	2	1978	200
MS	Watson Electric Generating Plant	4	1968	250
MS	Watson Electric Generating Plant	5	1973	500
MT	Colstrip	1	1975	358
MT	Colstrip	2	1976	358
MT	J E Corette	2	1968	191
NC	Asheville	1	1964	207

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
NC	Asheville	2	1971	207
NC	Belews Creek	1	1974	1080
NC	Belews Creek	2	1975	1080
NC	Cliffside	5	1972	571
NC	L V Sutton	3	1972	447
NC	Lee	3	1962	252
NC	Marshall	1	1965	350
NC	Marshall	2	1966	350
NC	Marshall	3	1969	648
NC	Marshall	4	1970	648
NC	Roxboro	1	1966	411
NC	Roxboro	2	1968	657
NC	Roxboro	3A	1973	745
NC	Roxboro	3B	1973	745
NC	Roxboro	4A	1980	745
NC	Roxboro	4B	1980	745
ND	Coal Creek	1	1979	506
ND	Coal Creek	2	1981	506
ND	Leland Olds	1	1966	216
ND	Leland Olds	2	1975	440
ND	Milton R Young	B1	1970	257
ND	Milton R Young	B2	1977	477
ND	R M Heskett	B2	1963	75
ND	Stanton	1	1967	172
NE	Gerald Gentleman Station	1	1979	681
NE	Gerald Gentleman Station	2	1982	681
NE	Lon D Wright Power Plant	8	1976	92
NE	Nebraska City	1	1979	616
NE	North Omaha	4	1963	136
NE	North Omaha	5	1968	218
NE	Sheldon	1	1968	109
NH	Merrimack	2	1968	346

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
NJ	B L England	1	1962	136
NJ	B L England	2	1964	163
NJ	Hudson	2	1968	660
NM	Four Corners	1	1963	190
NM	Four Corners	2	1963	190
NM	Four Corners	3	1964	253
NM	Four Corners	4	1969	818
NM	Four Corners	5	1970	818
NM	San Juan	1	1976	361
NM	San Juan	2	1973	350
NM	San Juan	3	1979	534
NM	San Juan	4	1982	534
NV	Mohave	1	1971	818
NV	Mohave	2	1971	818
NV	North Valmy	1	1981	254
NV	Reid Gardner	1	1965	114
NV	Reid Gardner	2	1968	114
NV	Reid Gardner	3	1976	114
NY	Dynegy Danskammer	4	1967	239
NY	Lovett	4	1966	180
NY	Lovett	5	1969	201
NY	S A Carlson	12	1963	58
OH	Avon Lake Power Plant	12	1970	680
OH	Bay Shore	3	1963	141
OH	Bay Shore	4	1968	218
OH	Cardinal	1	1967	615
OH	Cardinal	2	1967	615
OH	Cardinal	3	1977	650
OH	Conesville	3	1962	162
OH	Conesville	4	1973	842
OH	Conesville	5	1976	444
OH	Conesville	6	1978	444

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
OH	Eastlake	5	1972	680
OH	Gen J M Gavin	1	1974	1300
OH	Gen J M Gavin	2	1975	1300
OH	Hamilton	9	1974	51
OH	J M Stuart	1	1971	610
OH	J M Stuart	2	1970	610
OH	J M Stuart	3	1972	610
OH	J M Stuart	4	1974	610
OH	Killen Station	2	1982	666
OH	Lake Shore	18	1962	256
OH	Miami Fort	7	1975	557
OH	Miami Fort	8	1978	558
OH	Muskingum River	5	1968	615
OH	W H Sammis	4	1962	185
OH	W H Sammis	5	1967	318
OH	W H Sammis	6	1969	623
OH	W H Sammis	7	1971	623
OH	Walter C Beckjord	5	1962	245
OH	Walter C Beckjord	6	1969	461
OK	Muskogee	4	1977	572
OK	Muskogee	5	1978	572
OK	Northeastern	3313	1979	473
OK	Northeastern	3314	1980	473
OK	Sooner	1	1979	569
OK	Sooner	2	1980	569
OR	Boardman	1SG	1980	561
PA	Bruce Mansfield	1	1976	914
PA	Bruce Mansfield	2	1977	914
PA	Bruce Mansfield	3	1980	914
PA	Brunner Island	2	1965	405
PA	Brunner Island	3	1969	790
PA	Cheswick	1	1970	565

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
PA	Conemaugh	1	1970	936
PA	Conemaugh	2	1971	936
PA	Hatfields Ferry	1	1969	576
PA	Hatfields Ferry	2	1970	576
PA	Hatfields Ferry	3	1971	576
PA	Homer City	1	1969	660
PA	Homer City	2	1969	660
PA	Homer City	3	1977	692
PA	Keystone	1	1967	936
PA	Keystone	2	1968	936
PA	Mitchell	33	1963	299
PA	Montour	1	1972	823
PA	Montour	2	1973	819
PA	New Castle	5	1964	136
PA	Portland	2	1962	255
SC	Canadys Steam	CAN1	1962	136
SC	Canadys Steam	CAN2	1964	136
SC	Canadys Steam	CAN3	1967	218
SC	Dolphus M Grainger	1	1966	82
SC	Dolphus M Grainger	2	1966	82
SC	Jefferies	3	1970	173
SC	Jefferies	4	1970	173
SC	Wateree	WAT1	1970	386
SC	Wateree	WAT2	1971	386
SC	Williams	WIL1	1973	633
SC	Winyah	1	1975	315
SC	Winyah	2	1977	315
SD	Big Stone	1	1975	456
TN	Bull Run	1	1967	950
TN	Cumberland	1	1973	1300
TN	Cumberland	2	1973	1300
TX	Big Brown	1	1971	593

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
TX	Big Brown	2	1972	593
TX	Coleto Creek	1	1980	600
TX	Harrington Station	061B	1976	360
TX	Harrington Station	062B	1978	360
TX	J T Deely	1	1977	446
TX	J T Deely	2	1978	446
TX	Martin Lake	1	1977	793
TX	Martin Lake	2	1978	793
TX	Monticello	1	1974	593
TX	Monticello	2	1975	593
TX	Monticello	3	1978	793
TX	Sam Seymour	1	1979	615
TX	Sam Seymour	2	1980	615
TX	Sandow	4	1981	591
TX	W A Parish	WAP5	1977	734
TX	W A Parish	WAP6	1978	734
TX	Welsh	1	1977	558
TX	Welsh	2	1980	558
TX	Welsh	3	1982	558
UT	Hunter (Emery)	1	1978	446
UT	Hunter (Emery)	2	1980	446
UT	Huntington	1	1977	446
UT	Huntington	2	1974	446
VA	Chesapeake	4	1962	239
VA	Chesterfield	5	1964	359
VA	Chesterfield	6	1969	694
VA	Possum Point Power Station	4	1962	239
WA	Centralia	BW21	1972	730
WA	Centralia	BW22	1973	730
WI	Columbia	1	1975	512
WI	Columbia	2	1978	512
WI	Edgewater (4050)	4	1969	351

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
WI	Edgewater (4050)	5	1985	380
WI	Genoa	1	1969	346
WI	J P Madgett	B1	1979	387
WI	Manitowoc	7	1962	79
WI	Nelson Dewey	2	1962	114
WI	Pleasant Prairie	1	1980	617
WI	Pleasant Prairie	2	1985	617
WI	Pulliam	8	1964	136
WI	South Oak Creek	7	1965	318
WI	South Oak Creek	8	1967	324
WI	Valley (Wepco)	1	1968	136
WI	Valley (Wepco)	2	1968	136
WI	Valley (Wepco)	3	1969	136
WI	Valley (Wepco)	4	1969	136
WI	Weston	3	1981	350
WV	Fort Martin	1	1967	576
WV	Fort Martin	2	1968	576
WV	Harrison	1	1972	684
WV	Harrison	2	1973	684
WV	Harrison	3	1974	684
WV	John E Amos	1	1971	816
WV	John E Amos	2	1972	816
WV	John E Amos	3	1973	1300
WV	Mitchell	1	1971	816
WV	Mitchell	2	1971	816
WV	Mount Storm Power Station	1	1965	570
WV	Mount Storm Power Station	2	1966	570
WV	Mount Storm Power Station	3	1973	522
WV	Mountaineer (1301)	1	1980	1300
WV	Pleasants	1	1979	684
WV	Pleasants	2	1980	684
WY	Dave Johnston	BW43	1964	230

(continued)

Table B-2. Units that were Presumed to be BART-Eligible for Purposes of Modeling Emissions (continued)

State	FACILITY_NAME	UNITID	Online Year	Nameplate Capacity[a]
WY	Dave Johnston	BW44	1972	360
WY	Jim Bridger	BW71	1974	561
WY	Jim Bridger	BW72	1975	561
WY	Jim Bridger	BW73	1976	561
WY	Jim Bridger	BW74	1979	561
WY	Laramie River	1	1980	570
WY	Laramie River	2	1981	570
WY	Laramie River	3	1982	570
WY	Naughton	1	1963	163
WY	Naughton	2	1968	218
WY	Naughton	3	1971	326
WY	Wyodak	BW91	1978	362

[a] Nameplate capacity of generator connected to boiler.

B.3 Non-EGU Cost and Economic Impact Sensitivity Analyses

This appendix contains a number of sensitivity analyses for Scenarios 1 through 3 ($1,000/ton, $4,000/ton, and $10,000/ton) applied to the non-EGU source categories. These sensitivity analyses are the following:

- total capital costs of controlling both SO_2 and NO_x in 2015 for each illustrative scenario—calculated at a 7 percent discount rate (see Table B-3)
- total capital costs of controlling both SO_2 and NO_x in 2015—calculated at a 3 percent discount rate (see Table B-4)
- total capital costs of controlling both SO_2 and NO_x in 2015 for Scenario 2—calculated at a 10 percent discount rate (see Table B-5)
- total annualized costs of controlling both SO_2 and NO_x in 2015 for Scenario 2—calculated at a 10 percent discount rate (see Table B-6)
- total annualized and capital costs of controlling both SO_2 and NO_x for Scenario 2 in 2015 for a 25 percent increase in labor rates—calculated at a 7 percent discount rate (see Table B-7)
- total annualized and capital costs of controlling both SO_2 and NO_x for Scenario 2 in 2015 for a 25 percent decrease in labor rates—calculated at a 7 percent discount rate (see Table B-8)
- total annualized and capital costs of controlling both SO_2 and NO_x for Scenario 2 in 2015 for a 25 percent increase in energy prices—calculated at a 7 percent discount rate (see Table B-9)
- total annualized and capital costs of controlling both SO_2 and NO_x for Scenario 2 in 2015 for a 25 percent decrease in energy prices—calculated at a 7 percent discount rate (see Table B-10)

Table B-3. Total Capital Costs of Controlling Both SO_2 and NO_x for the Non-EGU BART Source Categories in 2015—7 Percent Discount Rate (million 1999$)

	Scenarios		
BART Source Category	**Scenario 1 $1,000/ton**	**Scenario 2 $4,000/ton**	**Scenario 3 $10,000/ton**
Industrial boilers	$422.3	$4,132.2	$6,324.9
Petroleum refineries	22.6	1,220.9	2,968.6
Kraft pulp mills	70.7	1,131.6	2,168.2
Portland cement plants	18.4	817.6	2,092.7
Hydrofluoric, sulfuric, and nitric acid plants	34.6	42.1	42.1
Chemical process plants	58.4	392.4	503.8
Iron and steel mills	2.6	162.9	227.6
Coke oven batteries	0.0	81.0	191.3
Sulfur recovery plants	0.3	1.0	1.0
Primary aluminum ore reduction plants	14.6	62.0	62.4
Lime kilns	9.9	16.6	140.1
Glass fiber processing plants	1.2	11.8	20.1
Municipal incinerators	0.0	4.6	4.6
Coal cleaning plants	0.0	4.0	4.0
Carbon black plants	0.02	0.9	0.9
Phosphate rock processing plants	0.0	0.7	1.5
Secondary metal production facilities	0.1	0.3	0.4
Total	$655.7	$8,082.7	$14,754.1

Table B-4. Total Capital Costs of Controlling Both SO_2 and NO_x for the Non-EGU BART Source Categories in 2015—3 Percent Discount Rate (million 1999$)

	Scenarios		
BART Source Category	Scenario 1 $1,000/ton	Scenario 2 $4,000/ton	Scenario 3 $10,000/ton
Industrial boilers	$1,101.3	$3,547.2	$4,549.1
Petroleum refineries	164.6	1,632.2	2,999.0
Kraft pulp mills	378.4	880.9	1,299.9
Portland cement plants	69.5	1,268.6	1,844.5
Hydrofluoric, sulfuric, and nitric acid plants	27.5	33.3	33.3
Chemical process plants	158.9	317.0	530.8
Iron and steel mills	2.2	173.7	240.7
Coke oven batteries	0.0	63.9	148.0
Sulfur recovery plants	0.2	0.8	0.8
Primary aluminum ore reduction plants	47.6	47.6	47.6
Lime kilns	12.6	106.9	106.9
Glass fiber processing plants	1.9	10.1	17.0
Municipal incinerators	0.0	3.2	3.2
Coal cleaning plants	0.0	3.3	3.3
Carbon black plants	0.02	0.7	0.7
Phosphate rock processing plants	0.0	1.1	1.1
Secondary metal production facilities	0.1	0.3	0.3
Total	$1,881.70	$8,090.92	$12,726.09

Table B-5. Total Capital Costs of Controlling Both SO_2 and NO_x for Scenario 2 ($4,000 per ton) Applied to the Non-EGU BART Source Categories in 2015 (million 1999$)—10 Percent Discount Rate

BART Source Category	Scenario 2 ($4,000 per ton)
Industrial boilers	$3,054.1
Petroleum refineries	862.6
Kraft pulp mills	788.4
Portland cement plants	154.1
Hydrofluoric, sulfuric, and nitric acid plants	49.3
Chemical process plants	398.7
Iron and steel mills	117.0
Coke oven batteries	95.2
Sulfur recovery plants	1.5
Primary aluminum ore reduction plants	22.4
Lime kilns	19.8
Glass fiber processing plants	13.1
Municipal incinerators	5.7
Coal cleaning plants	4.6
Carbon black plants	0.9
Phosphate rock processing plants	0.8
Secondary metal production facilities	0.3
Total	$5,588.6

Table B-6. Total Annualized Costs of Controlling Both SO_2 and NO_x for the Scenario 2 Applied to the Non-EGU BART Source Categories in 2015—10 Percent Discount Rate (million 1999$)

BART Source Category	Scenario 2 ($4,000 per ton)
Industrial boilers	$460.6
Petroleum refineries	137.0
Kraft pulp mills	116.7
Portland cement plants	36.0
Hydrofluoric, sulfuric, and nitric acid plants	25.3
Chemical process plants	72.7
Iron and steel mills	18.1
Coke oven batteries	22.4
Sulfur recovery plants	11.9
Primary aluminum ore reduction plants	3.1
Lime kilns	5.8
Glass fiber processing plants	5.8
Municipal incinerators	1.3
Coal cleaning plants	1.1
Carbon black plants	0.2
Phosphate rock processing plants	0.1
Secondary metal production facilities	0.05
Total	$928.29

Table B-7. Total Annualized and Capital Costs of Controlling Both SO_2 and NO_x for Scenario 2— Applied to the BART Non-EGU Source Categories in 2015—7 Percent Discount Rate—25 Percent Labor Rate Increase (million 1999$)

BART Source Category	Annualized Costs	Capital Costs
Industrial boilers	$521.7	$4,074.1
Petroleum refineries	180.8	1,221.0
Kraft pulp mills	119.1	1,012.2
Portland cement plants	175.6	817.6
Hydrofluoric, sulfuric, and nitric acid plants	23.4	42.1
Chemical process plants	71.5	392.4
Iron and steel mills	23.5	162.9
Coke oven batteries	18.6	80.0
Sulfur recovery plants	12.2	1.0
Primary aluminum ore reduction plants	7.8	62.0
Lime kilns	5.1	16.6
Glass fiber processing plants	5.3	11.8
Municipal incinerators	1.1	4.6
Coal cleaning plants	1.0	4.0
Carbon black plants	0.2	0.9
Phosphate rock processing plants	0.1	0.7
Secondary metal production facilities	0.04	0.3
Total	$1,167.13	$7,906.20

Table B-8. Total Annualized and Capital Costs of Controlling Both SO_2 and NO_x for Scenario 2 Applied to the Non-EGU BART Source Categories in 2015—7 Percent Discount Rate—25 Percent Labor Rate Decrease (million 1999$)

BART Source Category	Annualized Costs	Capital Costs
Industrial boilers	$525.5	$4,128.5
Petroleum refineries	179.5	1,221.0
Kraft pulp mills	118.9	1,012.2
Portland cement plants	173.9	817.6
Hydrofluoric, sulfuric, and nitric acid plants	23.3	42.1
Chemical process plants	70.1	392.4
Iron and steel mills	23.5	162.9
Coke oven batteries	18.7	81.0
Sulfur recovery plants	12.1	1.0
Primary aluminum ore reduction plants	7.8	62.0
Lime kilns	5.0	16.6
Glass fiber processing plants	5.3	11.8
Municipal incinerators	1.1	4.6
Coal cleaning plants	1.0	4.0
Carbon black plants	0.2	0.9
Phosphate rock processing plants	0.1	0.7
Secondary metal production facilities	0.04	0.3
Total	$1,165.83	$7,960.59

Table B-9. Total Annualized and Capital Costs of Controlling Both SO_2 and NO_x for Scenario 2— Applied to the BART Non-EGU Source Categories in 2015—7 Percent Discount Rate—25 Percent Energy Price Increase (million 1999$)

BART Source Category	Annualized Costs	Capital Costs
Industrial boilers	$522.2	$4,074.2
Petroleum refineries	180.7	1,220.0
Kraft pulp mills	118.2	1,012.2
Portland cement plants	179.3	817.6
Hydrofluoric, sulfuric, and nitric acid plants	24.2	42.1
Chemical process plants	70.8	392.4
Iron and steel mills	23.5	162.9
Coke oven batteries	18.7	81.1
Sulfur recovery plants	12.1	1.0
Primary aluminum ore reduction plants	7.8	62.0
Lime kilns	5.0	16.6
Glass fiber processing plants	5.3	11.8
Municipal incinerators	1.1	4.6
Coal cleaning plants	1.0	4.0
Carbon black plants	0.2	0.9
Phosphate rock processing plants	0.1	0.7
Secondary metal production facilities	0.04	0.3
Total	$1,171.27	$7,906.20

Table B-10. Total Annualized and Capital Costs of Controlling Both SO_2 and NO_x for Scenario 2 Applied to the BART Non-EGU Source Categories in 2015—7 Percent Discount Rate—25 Percent Energy Price Increase (million 1999$)

BART Source Category	Annualized Costs	Capital Costs
Industrial boilers	$25.0	$4,128.5
Petroleum refineries	179.7	1,221.0
Kraft pulp mills	118.8	1,012.2
Portland cement plants	170.2	817.6
Hydrofluoric, sulfuric, and nitric acid plants	22.6	42.1
Chemical process plants	70.7	392.4
Iron and steel mills	23.4	162.9
Coke oven batteries	18.6	81.1
Sulfur recovery plants	12.1	1.0
Primary aluminum ore reduction plants	7.8	62.0
Lime kilns	5.0	16.6
Glass fiber processing plants	5.3	11.8
Municipal incinerators	1.1	4.6
Coal cleaning plants	1.0	4.0
Carbon black plants	0.2	0.9
Phosphate rock processing plants	0.1	0.7
Secondary metal production facilities	0.04	0.3
Total	$1,161.68	$7,960.59

APPENDIX C

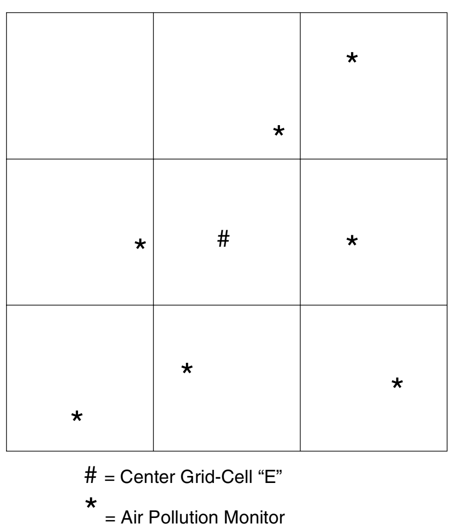
ADDITIONAL TECHNICAL INFORMATION SUPPORTING THE BENEFITS ANALYSIS

This appendix provides additional technical details about several important elements of the benefits analysis, including the spatial interpolation method and health effect pooling methods. Additional details on benefits methods can be found in the BenMAP User's Manual, available in the docket and online at http://www.epa.gov/ttn/ecas/benmodels.html.

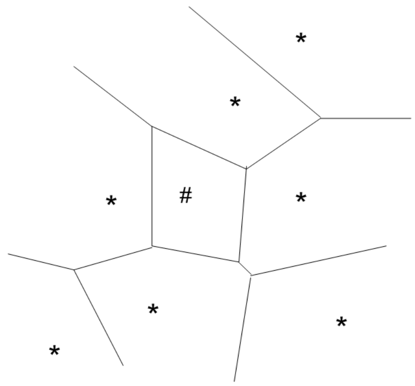
C.1 Voronoi Neighbor Averaging

In calculating the base year concentrations of PM species and ozone at model grid cells prior to scaling with model outputs, we used a spatial interpolation method known as Voronoi Neighbor Averaging (VNA).

The first step in VNA is to identify the set of neighboring monitors for each of the grid cells in the continental United States. The figure below presents nine grid cells and seven monitors, with the focus on identifying the set of neighboring monitors for grid cell E.



In particular, BenMAP identifies the nearest monitors, or “neighbors,” by drawing a polygon, or Voronoi cell, around the center of each grid cell. The polygons have the special property that the boundaries are the same distance from the two closest points.

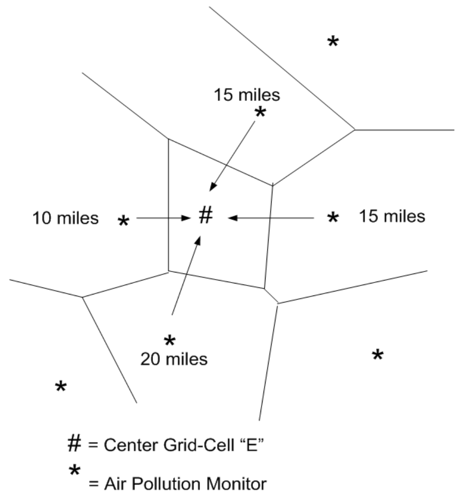


We then chose those monitors that share a boundary with the center of grid cell E. These are the nearest neighbors, and we used these monitors to estimate the air pollution level for this grid cell.

To estimate the air pollution level in each grid cell, BenMAP calculates the air pollution metrics for each of the neighboring monitors and then calculates an inverse-distance weighted average of the metrics. The further the monitor is from the grid cell center, the smaller the weight.

The weight for the monitor 20 kilometers from the center of grid cell E is calculated as follows:

$$d_{i,1} = \frac{\frac{1}{20}}{\left(\frac{1}{20} + \frac{1}{16} + \frac{1}{14}\right)} = 0.27 \ .$$



The weights for the other monitors would be calculated in a similar fashion.

C.2 The Random/Fixed Effect Pooling Procedure

Often more than one study has estimated a C-R function for a given pollutant-health endpoint combination. Each study provides an estimate of the pollutant coefficient, β, in the C-R function, along with a measure of the uncertainty of the estimate. Because uncertainty decreases as sample size increases, combining data sets is expected to yield more reliable estimates of β and therefore more reliable estimates of the incidence change predicted using β. Combining data from several comparable studies to analyze them together is often referred to as meta-analysis.

For a number of reasons, including data confidentiality, it is often impractical or impossible to combine the original data sets. Combining the *results* of studies to produce better estimates of β provides a second-best but still valuable way to synthesize information (DerSimonian and Laird, 1986). This is referred to as pooling. Pooling βs requires that all of the studies contributing estimates of β use the same functional form for the C-R function. That is, the βs must be measuring the same thing.

It is also possible to pool the study-specific estimates of incidence change derived from the C-R functions, instead of pooling the underlying βs themselves. For a variety of reasons, this is often possible when it is not feasible to pool the underlying βs. For example, if one study is log-linear and another is linear, we could not pool the βs because they are not different estimates of a coefficient in the same C-R function but are instead estimates of coefficients in different C-R functions. We can, however, calculate the incidence change predicted by each C-R function (for a given change in pollutant concentration and, for the log-linear function, a given baseline incidence rate) and pool these incidence changes. BenMAP allows the pooling of incidence changes predicted by several studies for the same pollutant-health endpoint group combination. It also allows the pooling of the corresponding study-specific estimates of monetary benefits.

As with estimates based on only a single study, BenMAP allows you to characterize the uncertainty surrounding pooled estimates of incidence change and/or monetary benefit. To do this, BenMAP pools the study-specific distributions of incidence changes (or monetary benefit) to derive a pooled distribution. This pooled distribution incorporates information from all the studies used in the pooling procedure.

C.2.1 Weights Used for Pooling

The relative contribution of any one study in the pooling process depends on the weight assigned to that study. A key component of the pooling process, then, is the determination of the weight given to each study. Various methods can be used to assign weights to studies. Below we discuss the possible weighting schemes that are available in BenMAP.

Subjective (User-specified) Weights

BenMAP allows the user the option of specifying the weights to be used. Suppose, for example, the user wants to simply average all study-specific results. He would then assign a weight of 1/N to each of the N study-specific distributions that are to be pooled. Note that subjective weights are limited to two decimal places and are normalized if they do not sum to one.

Automatically Generated Weights

A simple average has the advantage of simplicity but the disadvantage of not taking into account the uncertainty of each of the estimates. Estimates with great uncertainty surrounding them are given the same weight as estimates with very little uncertainty. A common method for weighting estimates involves using their variances. Variance takes into account both the consistency of data and the sample size used to obtain the estimate, two key factors that influence the reliability of results. BenMAP has two methods of automatically generating pooling weights using the variances of the input distributions—fixed effects pooling and random/fixed effects pooling.

The discussion of these two weighting schemes is first presented in terms of pooling the pollutant coefficients (the βs), because that most closely matches the discussion of the method for pooling study results as it was originally presented by DerSimonian and Laird (1986). We then give an overview of the analogous weighting process used within BenMAP to generate weights for incidence changes rather than βs.

C.3 Fixed Effects Weights

The fixed effects model assumes that there is a single true C-R relationship and therefore a single true value for the parameter β that applies everywhere. Differences among βs reported by different studies are therefore simply the result of sampling error. That is, each reported β is an estimate of the *same underlying parameter.* The certainty of an estimate is reflected in its variance (the larger the variance, the less certain the estimate). Fixed effects pooling therefore weights each estimate under consideration in proportion to the *inverse* of its variance.

Suppose there are n studies, with the i^{th} study providing an estimate β_i with variance v_i (I = 1, ..., n). Let

$$S = \Sigma \frac{1}{v_i} ,$$

denote the sum of the inverse variances. Then the weight, w_i, given to the ith estimate, β_i, is

$$w_i = \frac{1/v_i}{S} .$$

This means that estimates with small variances (i.e., estimates with relatively little uncertainty surrounding them) receive large weights and those with large variances receive small weights.

The estimate produced by pooling based on a fixed effects model, then, is just a weighted average of the estimates from the studies being considered, with the weights as defined above. That is,

$$\beta_{fe} = \Sigma\, w_i * \beta_i \, .$$

The variance associated with this pooled estimate is the inverse of the sum of the inverse variances:

$$v_{fe} = \frac{1}{\Sigma\ 1/v_i} \, .$$

Table C-1 shows the relevant calculations for this pooling for three sample studies.

Table C-1. Example of Fixed Effects Model Calculations

Study	β_i	v_i	$1/v_i$	w_i	$w_i*\beta_i$
1	0.75	0.1225	8.16	0.016	0.012
2	1.25	0.0025	400	0.787	0.984
3	1.00	0.0100	100	0.197	0.197
Sum			Σ = 508.16	Σ = 1.000	Σ = 1.193

The sum of weighted contributions in the last column is the pooled estimate of β based on the fixed effects model. This estimate (1.193) is considerably closer to the estimate from study 2 (1.25) than is the estimate (1.0) that simply averages the study estimates. This reflects the fact that the estimate from study 2 has a much smaller variance than the estimates from the other two studies and is therefore more heavily weighted in the pooling.

The variance of the pooled estimate, v_{fe}, is the inverse of the sum of the variances, or 0.00197. (The sums of the β_i and v_i are not shown, because they are of no importance. The sum of the $1/v_i$ is S, used to calculate the weights. The sum of the weights, w_i, i=1, ..., n, is 1.0, as expected).

C.4 Random/Fixed Effects Weights

An alternative to the fixed effects model is the random effects model, which allows the possibility that the estimates β_i from the different studies may in fact be estimates of *different* parameters, rather than just different estimates of a single underlying parameter. In studies of the effects of PM_{10} on mortality, for example, if the composition of PM_{10} varies among study locations the underlying relationship between mortality and PM_{10} may be different from one study location to another. For example, fine particles make up a greater fraction of PM_{10} in Philadelphia than in El Paso. If fine particles are disproportionately responsible for mortality relative to coarse particles, then one would expect the true value of β in Philadelphia to be greater than the true value of β in El Paso. This would violate the assumption of the fixed effects model.

The following procedure can test whether it is appropriate to base the pooling on the random effects model (vs. the fixed effects model). A test statistic, Q_w, the weighted sum of squared differences of the separate study estimates from the pooled estimate based on the fixed effects model, is calculated as

$$Q_w = \Sigma_i \frac{1}{v_i} (\beta_{fe} - \beta_i)^2.$$

Under the null hypothesis that there is a single underlying parameter, β, of which all the β_is are estimates, Q_w has a chi-squared distribution with n–1 degrees of freedom. (Recall that n is the number of studies in the meta-analysis.) If Q_w is greater than the critical value corresponding to the desired confidence level, the null hypothesis is rejected. That is, in this case the evidence does not support the fixed effects model, and the random effects model is assumed, allowing the possibility that each study is estimating a different β. (BenMAP uses a 5 percent one-tailed test.)

The weights used in a pooling based on the random effects model must take into account not only the within-study variances (used in a meta-analysis based on the fixed effects model) but the between-study variances as well. These weights are calculated as follows:

Using Q_w, the between-study variance, η^2, is

$$\eta^2 = \frac{Q_w - (n-1)}{\Sigma 1/v_i - \dfrac{\Sigma 1/v_i^2}{\Sigma 1/v_i}} \quad .$$

It can be shown that the denominator is always positive. Therefore, if the numerator is negative (i.e., if $Q_w < n-1$), then η^2 is a negative number, and it is not possible to calculate a random effects estimate. In this case, however, the small value of Q_w would presumably have led to accepting the null hypothesis described above, and the meta-analysis would be based on the fixed effects model. The remaining discussion therefore assumes that η^2 is positive.

Given a value for η^2, the random effects estimate is calculated in almost the same way as the fixed effects estimate. However, the weights now incorporate both the within-study variance (v_i) and the between-study variance (η^2). Whereas the weights implied by the fixed effects model used only v_i, the within-study variance, the weights implied by the random effects model use $v_i + \eta^2$.

Let $v_i^* = v_i + \eta^2$. Then

$$S^* = \Sigma \frac{1}{v_i^*} \ ,$$

and

$$w_i^* = \frac{1/v_i^*}{S^*} \quad .$$

The estimate produced by pooling based on the random effects model, then, is just a weighted average of the estimates from the studies being considered, with the weights as defined above. That is,

$$\beta_{rand} = \Sigma\ w_i^* \ * \ \beta_i \ .$$

The variance associated with this random effects pooled estimate is, as it was for the fixed effects pooled estimate, the inverse of the sum of the inverse variances:

$$v_{rand} = \frac{1}{\Sigma\ 1/v_i^*} \ .$$

The weighting scheme used in a pooling based on the random effects model is basically the same as that used if a fixed effects model is assumed, but the variances used in the calculations are different. This is because a fixed effects model assumes that the variability among the estimates from different studies is due only to sampling error (i.e., each study is thought of as representing just another sample from the same underlying population), while the random effects model assumes that there is not only sampling error associated with each study, but that there is also *between-study* variability—each study is estimating a different underlying β. Therefore, the sum of the within-study variance and the between-study variance yields an overall variance estimate.

C.5 Fixed Effects and Random/Fixed Effects Weighting to Pool Incidence Change Distributions and Dollar Benefit Distributions

Weights can be derived for pooling incidence changes predicted by different studies, using either the fixed effects or the fixed/random effects model, in a way that is analogous to the derivation of weights for pooling the βs in the C-R functions. As described above, BenMAP generates a Latin hypercube representation of the distribution of incidence change corresponding to each C-R function selected. The means of those study-specific Latin hypercube distributions of incidence change are used in exactly the same way as the reported βs are used to calculate fixed effects and random effects weights described above. The variances of incidence change are used in the same way as the variances of the βs. The formulas above for calculating fixed effects weights, for testing the fixed effects hypothesis, and for calculating random effects weights can all be used by substituting the mean incidence change for the ith C-R function for β_i and the variance of incidence change for the ith C-R function for v_i.[1]

Similarly, weights can be derived for dollar benefit distributions. As described above, BenMAP generates a Latin hypercube representation of the distribution of dollar benefits. The means of those Latin hypercube distributions are used in exactly the same way as the reported βs are used to calculate the fixed effects and random effects weights described above. The variances of dollar benefits are used in the same way as the variances of the βs. The formulas above for calculating fixed effects weights, for testing the fixed effects hypothesis, and for calculating random effects weights can all be used by substituting the mean dollar benefit change for the ith valuation for β_i and the variance of dollar benefits for the ith valuation for v_i.

BenMAP always derives fixed effects and random/fixed effects weights using nationally aggregated results, and uses those weights for pooling at each grid cell (or county, etc., if the user chooses to aggregate results prior to pooling). This is done because BenMAP does not include any regionally based uncertainty—that is, all uncertainty is at the national level in BenMAP, and all regional differences (e.g., population) are treated as certain.

C.6 Reference

DerSimonian, R. and N. Laird 1986. "Meta-analysis in Clinical Trials." *Controlled Clinical Trials* 7(3):177-188.

[1] There may be a problem with transferring the fixed effects hypothesis test to "incidence change space." The test statistic to test the fixed effects model is a chi-squared random variable. In the original paper on this pooling method, DerSimonian and Laird (1986) were discussing the pooling of estimates of parameters, which are generally normally distributed. The incidence changes predicted from a C-R function will not be normally distributed if the C-R function is not a linear function of the pollutant coefficient, which, in most cases it is not. (Most C-R functions are log-linear.) In that case, the test statistic may not be chi-square distributed. However, most log-linear C-R functions are *nearly* linear because their coefficients are very small. In that case the test statistic is likely to be *nearly* chi-square distributed.

APPENDIX D

VISIBILITY BENEFITS METHODOLOGY

Visibility degradation estimates used in this analysis are generated by the CMAQ model. To conduct the visibility benefits analysis, however, we need visibility data at the county level. To convert CMAQ visibility data from the square grid to the county level, we use the following rule: if a county center falls within a given CMAQ grid cell, we assign that CMAQ grid cell's visibility values to that county. Because the modeled air quality-related changes in visibility are directly used in the benefits analysis, the methodology for predicting visibility changes is not discussed here. The visibility estimation procedure is described in detail in EPA (2000), and is based on the methods in Sisler (1996).

Economic benefits may result from two broad categories of visibility changes: (1) changes in "residential" visibility—i.e., the visibility in and around the locations where people live; and (2) changes in "recreational" visibility at Class I areas—i.e., visibility at Class I national parks and wilderness areas.[1] In this analysis, only those recreational benefits in Class I areas that have been directly studied (in California, the Southeast, and the Southwest) are included in the primary presentation of benefits; residential benefits and recreational benefits in all U.S. Class I areas are presented as alternative calculations of visibility benefits.

Within the category of recreational visibility, further distinctions have been made. There is evidence (Chestnut and Rowe, 1990) that an individual's WTP for improvements in visibility at a Class I area is influenced by whether it is in the region in which the individual lives, or whether it is somewhere else. In general people appear to be willing to pay more for visibility improvements at parks and wilderness areas that are "in-region" than at those that

[1] Hereafter referred to as Class I areas, which are defined as areas of the country such as national parks, national wilderness areas, and national monuments that have been set aside under Section 162(a) of the Clean Air Act to receive the most stringent degree of air quality protection. Class I federal lands fall under the jurisdiction of three federal agencies, the National Park Service, the Fish and Wildlife Service, and the Forest Service.

are "out-of-region." This is plausible, because people are more likely to visit, be familiar with, and care about parks and wilderness areas in their own part of the country.

To value estimated visibility changes, we are using an approach consistent with economic theory. Below we discuss an application of the Constant Elasticity of Substitution (CES) utility function approach[2] to value both residential visibility improvements and visibility improvements at Class I areas in the United States. This approach is based on the preference calibration method developed by Smith, Van Houtven, and Pattanayak (1999). The presentation of this methodology is organized as follows. The basic utility model is presented in Section D.1. In Section D.2 we discuss the measurement of visibility, and the mapping from environmental "bads" to environmental "goods." In Sections D.3 and D.4 we summarize the information that is available to estimate the parameters of the model corresponding to visibility at in-region and out-of-region Class I areas, and visibility in residential areas, respectively, and we describe the methods used to estimate these parameters. Section D.5 synthesizes the results.

D.1 Basic Utility Model

We begin with a CES utility function in which a household derives utility from

(1) "all consumption goods," X,

(2) visibility in the residential area in which the household is located ("residential visibility"),[3]

(3) visibility at Class I areas in the same region as the household ("in-region recreational visibility"), and

(4) visibility at Class I areas outside the household's region ("out-of-region recreational visibility").

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[2] The constant elasticity of substitution utility function has been chosen for use in this analysis because of its flexibility when illustrating the degree of substitutability present in various economic relationships (in this case, the trade-off between income and improvements in visibility).

[3] We remind the reader that, although residential and recreational visibility benefits estimation is discussed simultaneously in this section, benefits are calculated and presented separately for each visibility category.

There are a total of six regions being considered, so there are five regions for which any household is out of region. The utility function of a household in the n^{th} residential area and the i^{th} region of the country is:

$$U_{ni} = (X^{\rho} + \theta Z_n^{\rho} + \sum_{k=1}^{N_i} \gamma_{ik} Q_{ik}^{\rho} + \sum_{j \neq i} \sum_{k=1}^{N_j} \delta_{jk} Q_{jk}^{\rho})^{1/\rho} \quad ,$$
$$\theta > 0, \gamma_{ik} > 0, \forall\, i,k,\ \delta_{jk} > 0, \forall\, j,k,\ \ \rho \leq 1.$$

where

Z_n = the level of visibility in the nth residential area;

Q_{ik} = the level of visibility at the k^{th} in-region park (i.e., the kth park in the ith region);

Q_{jk} = the level of visibility at the k^{th} park in the j^{th} region (for which the household is out of region), $j \neq i$;

N_i = the number of Class I areas in the i^{th} region;

N_j = the number of Class I areas in the j^{th} region (for which the household is out of region), $j \neq i$; and

θ, the γ's and δ's are parameters of the utility function corresponding to the visibility levels at residential areas and at in-region and out-of-region Class I areas, respectively. In particular, the γ_{ik}'s are the parameters corresponding to visibility at in-region Class I areas; the δ_1's are the parameters corresponding to visibility at Class I areas in region 1 (California), if $i \neq 1$; the δ_2's are the parameters corresponding to visibility at Class I areas in region 2 (Colorado Plateau), if $i \neq 2$, and so forth. Because the model assumes that the relationship between residential visibility and utility is the same everywhere, there is only one θ. The parameter ρ in this CES utility function is an important determinant of the slope of the marginal WTP curve associated with any of the environmental quality variables. When $\rho=1$, the marginal WTP curve is horizontal. When $\rho<1$, it is downward sloping.

The household's budget constraint is:

$$m - p \cdot X \leq 0 \ ,$$

where m is income, and p is the price of X. Without loss of generality, set p = 1. The only choice variable is X. The household maximizes its utility by choosing X=m. The indirect utility function for a household in the n[th] residential area and the ith region is therefore

$$V_{ni}(m, Z_n, Q; \theta, \gamma, \delta, \rho) = (m^\rho + \theta Z_n^\rho + \sum_{k=1}^{N_i} \gamma_{ik} Q_{ik}^\rho + \sum_{j \neq i} \sum_{k=1}^{N_j} \delta_{jk} Q_{jk}^\rho)^{1/\rho} \quad ,$$

where Q denotes the vector of vectors, Q_1, Q_2, Q_3, Q_4, Q_5, and Q_6, and the unsubscripted γ and δ denote vectors as well.

Given estimates of ρ, θ, the γ's and the δ's, the household's utility function and the corresponding WTP functions are fully specified. The household's WTP for any set of changes in the levels of visibility at in-region Class I areas, out-of-region Class I areas, and the household's residential area can be shown to be:

$$WTP_{ni}(\Delta Z, \Delta Q) = m - [\, m^\rho + \theta(Z_{0n}^\rho - Z_{1n}^\rho) + \sum_{k=1}^{N_i} \gamma_{ik}(Q_{0ik}^\rho - Q_{1ik}^\rho) + \sum_{j \neq i} \sum_{k=1}^{N_j} \delta_{jk}(Q_{0jk}^\rho - Q_{1jk}^\rho)\,]^{1/\rho} \quad .$$

The household's WTP for a single visibility improvement will depend on its order in the series of visibility improvements the household is valuing. If it is the first visibility improvement to be valued, the household's WTP for it follows directly from the previous equation. For example, the household's WTP for an improvement in visibility at the first in-region park, from $Q_{i1} = Q_{0i1}$ to $Q_{i1} = Q_{1i1}$, is

$$WTP(\Delta Q_{i1}) = m - [m^\rho + \gamma_{i1}(Q_{0i1}^\rho - Q_{1i1}^\rho)]^{1/\rho} \quad ,$$

if this is the first (or only) visibility change the household values.

D.2 Measure of Visibility: Environmental "Goods" Versus "Bads"

In the above model, Q and Z are environmental "goods." As the level of visibility increases, utility increases. The utility function and the corresponding WTP function both have reasonable properties. The first derivative of the indirect utility function with respect to Q (or Z) is positive; the second derivative is negative. WTP for a change from Q_0 to a higher (improved) level of visibility, Q_1, is therefore a concave function of Q_1, with decreasing marginal WTP.

The measure of visibility that is currently preferred by air quality scientists is the deciview, which increases as visibility *decreases*. Deciview, in effect, is a measure of the *lack* of visibility. As deciviews increase, visibility, and therefore utility, decreases. The deciview, then, is a measure of an environmental "bad." There are many examples of environmental "bads"—all types of pollution are environmental "bads." Utility decreases, for example, as the concentration of particulate matter in the atmosphere increases.

One way to value decreases in environmental bads is to consider the "goods" with which they are associated, and to incorporate those goods into the utility function. In particular, if B denotes an environmental "bad," such that:

$$\frac{\partial V}{\partial B} < 0 \ ,$$

and the environmental "good," Q, is a function of B,

$$Q = F(B) \ ,$$

then the environmental "bad" can be related to utility via the corresponding environmental "good":[4]

$$V = V(m, Q) = V(m, F(B)) \ .$$

The relationship between Q and B, F(B), is an empirical relationship that must be estimated.

There is a potential problem with this approach, however. If the function relating B and Q is not the same everywhere (i.e., if for a given value of B, the value of Q depends on other factors as well), then there can be more than one value of the environmental good corresponding to any given value of the environmental bad, and it is not clear which value to use. This has been identified as a problem with translating deciviews (an environmental "bad") into visual range (an environmental "good"). It has been noted that, for a given deciview value, there can be many different visual ranges, depending on the other factors that affect visual range—such as light angle and altitude. We note here, however, that this

[4] There may be more than one "good" related to a given environmental "bad." To simplify the discussion, however, we assume only a single "good."

problem is not unique to visibility, but is a general problem when trying to translate environmental "bads" into "goods."[5]

In order to translate deciviews (a "bad") into visual range (a "good"), we use a relationship derived by Pitchford and Malm (1994) in which

$$DV = 10 * \ln\left(\frac{391}{VR}\right),$$

where DV denotes deciview and VR denotes visual range (in kilometers). Solving for VR as a function of DV yields

$$VR = 391 * e^{-0.1DV}.$$

This conversion is based on specific assumptions characterizing the "average" conditions of those factors, such as light angle, that affect visual range. To the extent that specific locations depart from the average conditions, the relationship will be an imperfect approximation.[6]

D.3 Estimating the Parameters for Visibility at Class I Areas: the γ's and δ's

As noted in Section 2, if we consider a particular visibility change as the first or the only visibility change valued by the household, the household's WTP for that change in visibility can be calculated, given income (m), the "shape" parameter, ρ, and the corresponding recreational visibility parameter. For example, a Southeast household's WTP for a change in visibility at in-region parks (collectively) from $Q_1 = Q_{01}$ to $Q_1 = Q_{11}$ is:

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[5] Another example of an environmental "bad" is particulate matter air pollution (PM). The relationship between survival probability (Q) and the ambient PM level is generally taken to be of the form

$$Q = 1 - \alpha e^{\beta PM}.$$

where α denotes the mortality rate (or level) when there is no ambient PM (i.e., when PM=0). However, α is implicitly a function of all the factors other than PM that affect mortality. As these factors change (e.g., from one location to another), α will change (just as visual range changes as light angle changes). It is therefore possible to have many values of Q corresponding to a given value of PM, as the values of α vary.

[6] Ideally, we would want the location-, time-, and meteorological condition-specific relationships between deciviews and visual range, which could be applied as appropriate. This is probably not feasible, however.

$$WTP(DQ_1) = m - [m^r + g_1(Q_{01}^r - Q_{11}^r)]^{1/r}$$

if this is the first (or only) visibility change the household values.

Alternatively, if we have estimates of m as well as WTP_1^{in} and WTP_1^{out} of in-region and out-of-region households, respectively, for a given change in visibility from Q_{01} to Q_{11} in Southeast parks, we can solve for γ_1 and δ_1 as a function of our estimates of m, WTP_1^{in} and WTP_1^{out}, for any given value of ρ. Generalizing, we can derive the values of γ and δ for the j^{th} region as follows:

$$\gamma_j = \frac{(m - WTP_j^{in})^\rho - m^\rho}{(Q_{0j}^\rho - Q_{1j}^\rho)}$$

and

$$\delta_j = \frac{(m - WTP_j^{out})^\rho - m^\rho}{(Q_{0j}^\rho - Q_{1j}^\rho)} \quad .$$

Chestnut and Rowe (1990) and Chestnut (1997) estimated WTP (per household) for specific visibility changes at national parks in three regions of the United States—both for households that are in-region (in the same region as the park) and for households that are out-of-region. The Chestnut and Rowe study asked study subjects what they would be willing to pay for each of three visibility improvements in the national parks in a given region. Study subjects were shown a map of the region, with dots indicating the locations of the parks in question. The WTP questions referred to the three visibility improvements in all the parks collectively; the survey did not ask subjects' WTP for these improvements in specific parks individually. Responses were categorized according to whether the respondents lived in the same region as the parks in question ("in-region" respondents) or in a different region ("out-of-region" respondents). The areas for which in-region and out-of-region WTP estimates are available from Chestnut and Rowe (1990), and the sources of benefits transfer-based estimates that we employ in the absence of estimates, are summarized in Table D-1. In all cases, WTP refers to WTP per household.

Table D-1. Available Information on WTP for Visibility Improvements in National Parks

Region of Park	Region of Household: In Region[a]	Region of Household: Out of Region[b]
1. California	WTP estimate from study	WTP estimate from study
2. Colorado Plateau	WTP estimate from study	WTP estimate from study
3. Southeast United States	WTP estimate from study	WTP estimate from study
4. Northwest United States	(based on benefits transfer from California)	
5. Northern Rockies	(based on benefits transfer from Colorado Plateau)	
6. Rest of United States	(based on benefits transfer from Southeast U.S.)	

[a] In-region" WTP is WTP for a visibility improvement in a park in the same region as that in which the household is located. For example, in-region WTP in the "Southeast" row is the estimate of the average Southeast household's WTP for a visibility improvement in a Southeast park.

[b] Out-of-region" WTP is WTP for a visibility improvement in a park that is not in the same region in which the household is located. For example, out-of-region WTP in the "Southeast" row is the estimate of WTP for a visibility improvement in a park in the Southeast by a household outside of the Southeast.

In the primary calculation of visibility benefits for this analysis, only visibility changes at parks within visibility regions for which a WTP estimate was available from Chestnut and Rowe (1990) are considered (for both in- and out-of-region benefits). Primary estimates will not include visibility benefits calculated by transferring WTP values to visibility changes at parks not included in the Chestnut and Rowe study. Transferred benefits at parks located outside of the Chestnut and Rowe visibility regions will, however, be included as an alternative calculation.

The values of the parameters in a household's utility function will depend on where the household is located. The region-specific parameters associated with visibility at Class I areas (that is, all parameters except the residential visibility parameter) are arrayed in Table D-2. The parameters in columns 1 through 3 can be directly estimated using WTP estimates from Chestnut and Rowe (1990) (the columns labeled "Region 1," "Region 2," and "Region 3").

Table D-2. Summary of Region-Specific Recreational Visibility Parameters to be Estimated in Household Utility Functions

Region of Household	Region of Park					
	Region 1	Region 2	Region 3	Region 4	Region 5	Region 6
Region 1	γ_1[a]	δ_2	δ_3	δ_4	δ_5	δ_6
Region 2	δ_1	γ_2	δ_3	δ_4	δ_5	δ_6
Region 3	δ_1	δ_2	γ_3	δ_4	δ_5	δ_6
Region 4	δ_1	δ_2	δ_3	γ_4	δ_5	δ_6
Region 5	δ_1	δ_2	δ_3	δ_4	γ_5	δ_6
Region 6	δ_1	δ_2	δ_3	δ_4	δ_5	γ_6

[a] The parameters arrayed in this table are region specific rather than park specific or wilderness area specific. For example, δ_1 is the parameter associated with visibility at " Class I areas in region 1" for a household in any region other than region 1. The benefits analysis must derive Class I area-specific parameters (e.g., δ_{1k}, for the kth Class I area in the first region).

For the three regions covered in Chestnut and Rowe (1990) (California, the Colorado Plateau, and the Southeast United States), we can directly use the in-region WTP estimates from the study to estimate the parameters in the utility functions corresponding to visibility at in-region parks (γ_1); similarly, we can directly use the out-of-region WTP estimates from the study to estimate the parameters for out-of-region parks (δ_1). For the other three regions not covered in the study, however, we must rely on benefits transfer to estimate the necessary parameters.

While Chestnut and Rowe (1990) provide useful information on households' WTP for visibility improvements in national parks, there are several significant gaps remaining between the information provided in that study and the information necessary for the benefits analysis. First, as noted above, the WTP responses were not park specific, but only region specific. Because visibility improvements vary from one park in a region to another, the benefits analysis must value park-specific visibility changes. Second, not all Class I areas in each of the three regions considered in the study were included on the maps shown to study subjects. Because the focus of the study was primarily national parks, most Class I wilderness areas were not included. Third, only three regions of the United States were included, leaving the three remaining regions without direct WTP estimates.

In addition, Chestnut and Rowe (1990) elicited WTP responses for *three different* visibility changes, rather than a single change. In theory, if the CES utility function accurately describes household preferences, and if all households in a region have the same preference structure, then households' three WTP responses corresponding to the three different visibility changes should all produce the same value of the associated recreational visibility parameter, given a value of ρ and an income, m. In practice, of course, this is not the case.

In addressing these issues, we take a three-phase approach:

(1) We estimate region-specific parameters for the region in the modeled domain covered by Chestnut and Rowe (1990) (California, the Colorado Plateau, and the Southeast)—γ_1, γ_2, and γ_3 and δ_1, δ_2, and δ_3.

(2) We infer region-specific parameters for those regions not covered by the Chestnut and Rowe study (the Northwest United States, the Northern Rockies, and the rest of the United States)— γ_4, γ_5, and γ_6 and δ_4, δ_5, and δ_6.

(3) We derive park- and wilderness area-specific parameters within each region (γ_{1k} and δ_{1k}, for k=1, ..., N_1; γ_{2k} and δ_{2k}, for k=1, ..., N_2; and so forth).

The question that must be addressed in the first phase is how to estimate a single region-specific in-region parameter and a single region-specific out-of-region parameter for each of the three regions covered in Chestnut and Rowe (1990) from study respondents' WTPs for *three different* visibility changes in each region. All parks in a region are treated collectively as if they were a single "regional park" in this first phase. In the second phase, we infer region-specific recreational visibility parameters for regions not covered in the Chestnut and Rowe study (the Northwest United States, the Northern Rockies, and the rest of the United States). As in the first phase, we ignore the necessity to derive park-specific parameters at this phase. Finally, in the third phase, we derive park- and wilderness area-specific parameters for each region.

D.3.1 Estimating Region-Specific Recreational Visibility Parameters for the Region Covered in the Chestnut and Rowe Study (Regions 1, 2, and 3)

Given a value of ρ and estimates of m and in-region and out-of-region WTPs for a change from Q_0 to Q_1 in a given region, the in-region parameter, γ, and the out-of-region parameter, δ, for that region can be solved for. Chestnut and Rowe (1990), however, considered not just one, but three visibility changes in each region, each of which results in a different calibrated γ and a different calibrated δ, even though in theory all the γ's should be the same and similarly, all the δ's should be the same. For each region, however, we must have only a single γ and a single δ.

Denoting $\hat{\gamma}_j$ as our estimate of γ for the j[th] region, based on all three visibility changes, we chose $\hat{\gamma}_j$ to best predict the three WTPs observed in the study for the three visibility improvements in the j[th] region. First, we calculated $\hat{\gamma}_{ji}$, i=1, 2, 3, corresponding to each of the three visibility improvements considered in the study. Then, using a grid search method beginning at the average of the three $\hat{\gamma}_{ji}$'s, we chose $\hat{\gamma}_j$ to minimize the sum of the squared differences between the WTPs we predict using $\hat{\gamma}_j$ and the three region-specific WTPs observed in the study. That is, we selected $\hat{\gamma}_j$ to minimize:

$$\sum_{i=1}^{3} (WTP_{ij}(\hat{\gamma}_j) - WTP_{ij})^2$$

where WTP_{ij} and $WTP_{ij}(\hat{\gamma}_j)$ are the observed and the predicted WTPs for a change in visibility in the j[th] region from $Q_0 = Q_{0i}$ to $Q_1 = Q_{1i}$, i=1, ..., 3. An analogous procedure was used to select an optimal δ, for each of the three regions in the Chestnut and Rowe study.

D.3.2 Inferring Region-Specific Recreational Visibility Parameters for Regions Not Covered in the Chestnut and Rowe Study (Regions 4, 5, and 6)

One possible approach to estimating region-specific parameters for regions not covered by Chestnut and Rowe (1990) (γ_4, γ_5, and γ_6 and δ_4, δ_5, and δ_6) is to simply assume that households' utility functions are the same everywhere, and that the environmental goods being valued are the same—e.g., that a change in visibility at national parks in California is the same environmental good to a Californian as a change in visibility at national parks in Minnesota is to a Minnesotan.

For example, to estimate δ_4 in the utility function of a California household, corresponding to visibility at national parks in the Northwest United States, we might assume that out-of-region WTP for a given visibility change at national parks in the Northwest United States is the same as out-of-region WTP for the same visibility change at national parks in California (income held constant). Suppose, for example, that we have an estimated mean WTP of out-of-region households for a visibility change from Q_{01} to Q_{11} at national parks in California (region 1), denoted WTP_1^{out}. Suppose the mean income of the out-of-region subjects in the study was m. We might assume that, for the same change in visibility at national parks in the Northwest United States, $WTP_4^{out} = WTP_1^{out}$ among out-of-region individuals with income m.

We could then derive the value of δ_4, given a value of ρ as follows:

$$\delta_4 = \frac{(m - WTP_4^{out})^\rho - m^\rho}{Q_{04}^\rho - Q_{14}^\rho}$$

where $Q_{04} = Q_{01}$ and $Q_{14} = Q_{11}$, (i.e., where it is *the same* visibility change in parks in region 4 that was valued at parks in the region 1).

This benefits transfer method assumes that (1) all households have the same preference structures and (2) what is being valued in the Northwest United States (by a California household) is the same as what is being valued in the California (by all out-of-region households). While we cannot know the extent to which the first assumption approximates reality, the second assumption is clearly problematic. National parks in one region are likely to differ from national parks in another region in both quality and quantity (i.e., number of parks).

One statistic that is likely to reflect both the quality and quantity of national parks in a region is the average annual visitation rate to the parks in that region. A reasonable way to gauge the extent to which out-of-region people would be willing to pay for visibility changes in parks in the Northwest United States versus in California might be to compare visitation rates in the two regions.[7] Suppose, for example, that twice as many visitor-days are spent in California parks per year as in parks in the Northwest United States per year. This could be an indication that the parks in California are in some way more desirable than those in the Northwest United States and/or that there are more of them—i.e., that the environmental goods being valued in the two regions ("visibility at national parks") are not the same.

A preferable way to estimate δ_4, then, might be to assume the following relationship:

[7] We acknowledge that reliance on visitation rates does not get at nonuse value.

$$\frac{WTP_4^{out}}{WTP_1^{out}} = \frac{n_4}{n_1}$$

(income held constant), where n_1 = the average annual number of visitor-days to California parks and n_4 = the average annual number of visitor-days to parks in the Northwest United States. This implies that

$$WTP_4^{out} = \frac{n_4}{n_1} * WTP_1^{out}$$

for the same change in visibility in region 4 parks among out-of-region individuals with income m. If, for example, $n_1 = 2n_4$, WTP_4^{out} would be half of WTP_1^{out}. The interpretation would be the following: California national parks have twice as many visitor-days per year as national parks in the Northwest United States; therefore they must be twice as desirable/plentiful; therefore, out-of-region people would be willing to pay twice as much for visibility changes in California parks as in parks in the Northwest United States; therefore a Californian would be willing to pay only half as much for a visibility change in national parks in the Northwest United States as an out-of-region individual would be willing to pay for the same visibility change in national parks in California. This adjustment, then, is based on the premise that the environmental goods being valued (by people out of region) are not the same in all regions.

The parameter δ_4 is estimated as shown above, using this adjusted WTP_4^{out}. The same procedure is used to estimate δ_5 and δ_6. We estimate γ_4, γ_5, and γ_6 in an analogous way, using the in-region WTP estimates from the transfer regions, e.g.,

$$WTP_4^{in} = \frac{n_4}{n_1} * WTP_1^{in} \quad .$$

D.3.3 Estimating Park- and Wilderness Area-Specific Parameters

As noted above, Chestnut and Rowe (1990) estimated WTP for a region's national parks collectively, rather than providing park-specific WTP estimates. The γ's and δ's are therefore the parameters that would be in household utility functions if there were only a single park in each region, or if the many parks in a region were effectively indistinguishable from one another. Also noted above is the fact that the Chestnut and Rowe study did not include all Class I areas in the regions it covered, focusing primarily on national parks rather than wilderness areas. Most Class I wilderness areas were not represented on the maps shown to study subjects. In California, for example, there are 31 Class I areas, including 6 national parks and 25 wilderness areas. The Chestnut and Rowe study map of California included only 10 of these Class I areas, including all 6 of the national parks. It is unclear whether subjects had in mind "all parks and wilderness areas" when they offered their WTPs for visibility improvements, or whether they had in mind the specific number of (mostly) parks that were shown on the maps. The derivation of park- and wilderness area-specific parameters depends on this.

D.3.4 Derivation of Region-Specific WTP for National Parks and Wilderness Areas

If study subjects were lumping all Class I areas together in their minds when giving their WTP responses, then it would be reasonable to allocate that WTP among the specific parks and wilderness areas in the region to derive park- and wilderness area-specific γ's and δ's for the region. If, on the other hand, study subjects were thinking only of the (mostly) parks shown on the map when they gave their WTP response, then there are two possible approaches that could be taken. One approach assumes that households would be willing to pay some additional amount for the same visibility improvement in additional Class I areas that were not shown, and that this additional amount can be estimated using the same benefits transfer approach used to estimate region-specific WTPs in regions not covered by Chestnut and Rowe (1990).

However, even if we believe that households would be willing to pay some additional amount for the same visibility improvement in additional Class I areas that were not shown, it is open to question whether this additional amount can be estimated using benefits transfer methods. A third possibility, then, is to simply omit wilderness areas from the benefits analysis. For this analysis we calculate visibility benefits assuming that study subjects lumped all Class I areas together when stating their WTP, even if these Class I areas were not present on the map.

D.3.5 Derivation of Park- and Wilderness Area-Specific WTPs, Given Region-Specific WTPs for National Parks and Wilderness Areas

The first step in deriving park- and wilderness area-specific parameters is the estimation of park- and wilderness area-specific WTPs. To derive park and wilderness area-specific WTPs, we apportion the region-specific WTP to the specific Class I areas in the region according to each area's share of the region's visitor-days. For example, if WTP_1^{in} and WTP_1^{out} denote the mean household WTPs in the Chestnut and Rowe (1990) study among respondents who were in-region-1 and out-of-region-1, respectively, n_{1k} denotes the annual average number of visitor-days to the kth Class I area in California, and n_1 denotes the annual average number of visitor-days to all Class I areas in California (that are included in the benefits analysis), then we assume that

$$WTP_{1k}^{in} = \frac{n_{1k}}{n_1} * WTP_1^{in} \ ,$$

and

$$WTP_{1k}^{out} = \frac{n_{1k}}{n_1} * WTP_1^{out} \ .$$

Using WTP_j^{in} and WTP_j^{out}, either from the Chestnut and Rowe study (for j = 1, 2, and 3) or derived by the benefits transfer method (for j = 4, 5, and 6), the same method is used to derive Class I area-specific WTPs in each of the six regions.

While this is not a perfect allocation scheme, it is a reasonable scheme, given the limitations of data. Visitors to national parks in the United States are not all from the United States, and certainly not all from the region in which the park is located. A very large proportion of the visitors to Yosemite National Park in California, for example, may come from outside the United States. The above allocation scheme implicitly assumes that the relative frequencies of visits to the parks in a region *from everyone in the world* is a reasonable index of the relative WTP of an average household in that region (WTP_j^{in}) or out of that region (but in the United States) (WTP_j^{out}) for visibility improvements at these parks.[8]

[8] This might be thought of as two assumptions: (1) that the relative frequencies of visits to the parks in a region *from everyone in the world* is a reasonable representation of the relative frequency of visits *from people in the United States*—i.e., that the parks that are most popular (receive the most visitors per year) in general are also the most popular among Americans; and (2) that the relative frequency with which Americans visit each

A possible problem with this allocation scheme is that the relative frequency of visits is an indicator of use value but not necessarily of nonuse value, which may be a substantial component of the household's total WTP for a visibility improvement at Class I areas. If park A is twice as popular (i.e., has twice as many visitors per year) as park B, this does not necessarily imply that a household's WTP for an improvement in visibility at park A is twice its WTP for the same improvement at park B. Although an allocation scheme based on relative visitation frequencies has some obvious problems, however, it is still probably the best way to allocate a collective WTP.

D.3.6 Derivation of Park- and Wilderness Area-Specific Parameters, Given Park- and Wilderness Area-Specific WTPs

Once the Class I area-specific WTPs have been estimated, we could derive the park- and wilderness area-specific γ's and δ's using the method used to derive region-specific γ's and δ's. Recall that method involved (1) calibrating γ and δ to each of the three visibility improvements in the Chestnut and Rowe study (producing three γ's and three δ's), (2) averaging the three γ's and averaging the three δ's, and finally, (3) using these average γ and δ as starting points for a grid search to find the optimal γ and the optimal δ—i.e., the γ and δ that would allow us to reproduce, as closely as possible, the three in-region and three out-of-region WTPs in the study for the three visibility changes being valued.

Going through this procedure for each national park and each wilderness area separately would be very time consuming, however. We therefore used a simpler approach, which produces very close approximations to the γ's and δ's produced using the above approach. If:

WTP_j^{in} = the in-region WTP for the change in visibility from Q_0 to Q_1 in the j^{th} region;

WTP_{jk}^{in}= the in-region WTP for the same visibility change (from Q_0 to Q_1) in the k^{th} Class I area in the jth region (= s_{jk}*WTP_j^{in}, where s_{jk} is the k^{th} area's share of visitor-days in the j^{th} region);

m = income;

γ_j* = the optimal value of γ for the jth region; and

of their parks is a good index of their relative WTPs for visibility improvements at these parks.

γ_{jk} = the value of γ_{jk} calibrated to WTP_{jk}^{in} and the change from Q_0 to Q_1;

then[9]:

$$\gamma_j^* \approx \frac{(m - WTP_j^{in})^\rho - m^\rho}{(Q_0^\rho - Q_1^\rho)}$$

and

$$\gamma_{jk} = \frac{(m - WTP_{jk}^{in})^\rho - m^\rho}{(Q_0^\rho - Q_1^\rho)}$$

which implies that:

$$\gamma_{jk} \approx a_{jk} * \gamma_j^*,$$

where:

$$a_{jk} = \frac{(m - WTP_{jk}^{in})^\rho - m^\rho}{(m - WTP_j^{in})^\rho - m^\rho}.$$

We use the adjustment factor, a_{jk}, to derive γ_{jk} from γ_j^*, for the k^{th} Class I area in the j^{th} region. We use an analogous procedure to derive δ_{jk} from δ_j^* for the k^{th} Class I area in the j^{th} region (where, in this case, we use WTP_j^{out} and WTP_{jk}^{out} instead of WTP_j^{in} and WTP_{jk}^{in}).[10]

[9] γ_j^* is only approximately equal to the right-hand side because, although it is the optimal value designed to reproduce as closely as possible all three of the WTPs corresponding to the three visibility changes in the Chestnut and Rowe study, γ_j^* will not exactly reproduce any of these WTPs.

[10] This method uses a single in-region WTP and a single out-of-region WTP per region. Although the choice of WTP will affect the resulting adjustment factors (the a_{jk}'s) and therefore the resulting γ_{jk}'s and δ_{jk}'s, the effect is negligible. We confirmed this by using each of the three in-region WTPs in California and comparing the resulting three sets of γ_{jk}'s and δ_{jk}'s, which were different from each other by about one one-hundredth of a percent.

D.4 Estimating the Parameter for Visibility in Residential Areas: θ

The estimate of θ is based on McClelland et al. (1991), in which household WTP for improvements in residential visibility was elicited from respondents in Chicago and Atlanta. A notable difference between the Chestnut and Rowe study and the McClelland study is that, while the former elicited WTP responses for three different visibility changes, the latter considered only one visibility change. The estimation of θ was therefore a much simpler procedure, involving a straightforward calibration to the single income and WTP in the study:

$$\theta = \frac{(m - WTP)^{\rho} - m^{\rho}}{(Z_0^{\rho} - Z_1^{\rho})} .$$

D.5 Putting it All Together: The Household Utility and WTP Functions

Given an estimate of θ, derived as shown in Section D.4, and estimates of the γ's and δ's, derived as shown in Section D.3, based on an assumed or estimated value of ρ, the utility and WTP functions for a household in any region are fully specified. We can therefore estimate the value to that household of visibility changes from any baseline level to any alternative level in the household's residential area and/or at any or all of the Class I areas in the United States, in a way that is consistent with economic theory. In particular, the WTP of a household in the ith region and the nth residential area for any set of changes in the levels of visibility at in-region Class I areas, out-of-region Class I areas, and the household's residential area (given by equation (24)) is:

$$WTP_{ni}(\Delta Z, \Delta Q) = m - [\, m^{\rho} + \theta(Z_{0n}^{\rho} - Z_{1n}^{\rho}) + \sum_{k=1}^{N_i} \gamma_{ik}(Q_{0ik}^{\rho} - Q_{1ik}^{\rho}) + \sum_{j \neq i} \sum_{k=1}^{N_j} \delta_{jk}(Q_{0jk}^{\rho} - Q_{1jk}^{\rho})\,]^{1/\rho} .$$

The national benefits associated with any suite of visibility changes is properly calculated as the sum of these household WTPs for those changes. The benefit of any subset of visibility changes (e.g., changes in visibility only at Class I areas in California) can be calculated by setting all the other components of the WTP function to zero (that is, by assuming that all other visibility changes that are not of interest are zero). This is effectively the same as assuming that the subset of visibility changes of interest is the first or the only set of changes being valued by households. Estimating benefit components in this way will yield slightly upward biased estimates of benefits, because disposable income, m, is not being reduced by the WTPs for any prior visibility improvements. That is, each visibility improvement (e.g., visibility at Class I areas in the California) is assumed to be the first, and they cannot all be the first. The upward bias should be extremely small, however, because all of the WTPs for visibility changes are likely to be very small relative to income.

D.6 References

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APPENDIX E

BENEFITS AND COSTS OF THE CLEAN AIR INTERSTATE RULE, THE CLEAN AIR VISIBILITY RULE, AND THE CLEAN AIR INTERSTATE RULE PLUS THE CLEAN AIR VISIBILITY RULE

This appendix presents the benefits and costs for the CAIR program (CAIR final rule plus the New Jersey and Delaware proposal),[1] the EGU requirements for Best Available Retrofit Technology (BART) Guidelines for the Regional Haze Rule, and the CAIR program in the CAIR region plus BART control for EGUs elsewhere in the country (CAIR Plus BART in the Non-CAIR Region). It is important to note that the CAIR, CAIR Plus BART in the Non-CAIR Region, and BART Nationwide benefit and costs estimates reflect controls for the EGU source category only, while the BART regulation will potentially affect 26 source categories. The analysis presented in this appendix was conducted to show the benefits and costs of the alternative programs addressing the EGU sector.[2] A comparison of the BART nationwide scenario with the CAIR plus BART in the Non-CAIR Region scenario provides some information on the possible benefits and costs for BART for EGU sources in the Non-CAIR Region.

The control strategy assumptions for the BART nationwide and BART portion of the CAIR Plus BART in the Non-CAIR Region scenarios differ from the BART scenarios (Scenario 1, Scenario 2, and Scenario 3) analyzed in this RIA. Because of the differing control strategy modeling for the EGU source category, the benefits and costs reported in this appendix for EGU sources will differ from these scenarios. The analysis conducted for this appendix assumes that all units greater than 100 MW that do not currently have scrubbers are required to reduce emissions from uncontrolled levels by 90 percent or meet a 0.1 lb/mmbtu SO_2 emission rate limit. It also assumes that all BART units greater than 25 MW are

[1]The modeling for the rule includes annual SO_2 and NO_x controls for Arkansas and results in a minimal overstatement of the benefits and costs of the CAIR program (CAIR final plus the New Jersey and Delaware proposal).

[2]Note that the net benefits reported in this appendix are estimated using the private costs of the respective rules rather than social costs. Thus, the net benefits shown for the CAIR program in this appendix differ somewhat from the estimates presented in the body of this report.

required to meet an emission rate limit of 0.2 lbs/mmbtu. This analysis was conducted to support the "Better than BART" analysis conducted for the CAIR final rule and was a conservative (i.e., control on most units) look at controls that states might choose to require on sources not subject to presumptive BART.

As Table E-1 shows, annual net benefits for the CAIR program are $97.4 billion in 2015. This estimate compares to annual net benefits of $44.3 billion for BART nationwide program and $100 billion for CAIR Plus BART in the Non-CAIR Region (assuming a 3 percent discount rate). These estimates become $82.7 billion for CAIR, $84.9 billion for CAIR Plus BART in the Non-CAIR Region, and $37.0 billion for the BART nationwide program assuming a 7 percent discount rate. The analysis shows that if one assumes the CAIR program exists, the incremental benefits of requiring BART controls for the EGU source category only in areas outside the CAIR region are approximately $3.2 to $4 billion (7 percent and 3 percent discount rate, respectively). Related incremental costs are approximately $1 billion. All estimates are shown in 1999 dollars. Table E-2 lists the reduction in health incidence resulting from the CAIR program, CAIR Plus BART in the Non-CAIR Region, and BART nationwide. Table E-3 depicts the monetary value of the benefit categories listed on Table E-2. We were unable to estimate all of the benefits and disbenefits associated with these rulemakings as summarized in Table 1-4. These unquantified effects are represented by the letter B.

Table E-1. Summary of Annual Benefits, Costs, and Net Benefits of the Clean Air Interstate Rule, 2015 (billions of 1999 dollars)[a]

Description	CAIR Program[g]	CAIR Plus BART in the Non-CAIR Region[g]	BART Nationwide
Private costs[b]	$3.57	$4.55	$5.19
Social benefits[c,d,e]			
3 percent discount rate	$101 + B	$105 + B	$49.5+ B
7 percent discount rate	$86.3 + B	$89.5 + B	$42.2 + B
Health-related benefits:			
3 percent discount rate	99.3	103	48.8
7 percent discount rate	84.5	87.6	41.5
Visibility benefits	1.78	1.89	0.699
Net benefits (benefits-costs)[e,f]			
3 percent discount rate	$97.4 + B	$100 + B	$44.3 + B
7 percent discount rate	$82.7 + B	$84.9+ B	$37.0 + B

[a] All estimates are rounded to three significant digits for ease of presentation and computation. These annual estimates represent the benefits and costs of these regulatory programs expected to occur in 2015. BART estimates reflect benefits and costs for controls for the EGU source category only and a conservative (i.e., controls on most units) look at controls that states might choose to require on sources not subject to presumptive BART. For these reasons, the benefits and costs of BART in this appendix differ from Scenarios 1, 2, and 3 in this RIA.

[b] Note that costs presented are the annual total private costs to the power sector of reducing pollutants including NO_x and SO_2. The costs are estimated using the IPM and assume affected firms face cost of capital ranging from 5.34 to 6.74 percent. CAIR costs reflect costs for the CAIR region. Costs for CAIR Plus BART in the Non-CAIR Region and BART nationwide are national cost estimates.

[c] Total benefits are driven primarily by PM-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits in 2015. Benefits in this table are nationwide (with the exception of ozone and visibility) and are associated with NO_x and SO_2 reductions. Ozone benefits relate to the eastern United States. Visibility benefits relate to Class I areas in the southeastern United States. While ozone benefits are expected for each of these programs, ozone benefits are included in the CAIR program benefits estimates only. The benefit estimates for CAIR Plus in the Non-CAIR Region BART and BART nationwide do not include ozone benefits. Inclusion of ozone benefits would not likely alter the conclusions reached on the magnitude of the difference between the scenarios.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential effects categories that have not been quantified and monetized are listed in Table 1-4 and Table 1-5.

[e] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 4. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

[f] Net benefits are rounded to the nearest $100 million. Columnar totals may not sum due to rounding.

[g] CAIR costs and benefits are the estimates for the CAIR program that includes the promulgated CAIR and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware. Modeling for CAIR assumes annual SO_2 and NO_x controls for Arkansas that is not a part of the CAIR program. Thus, the benefits and costs reported are slightly overstated.

Table E-2. Clean Air Interstate Rule: Estimated Reduction in Health Effects (Incidence)—2015

Health Effect	CAIR Program[f]	CAIR Plus BART in the Non-CAIR Region[f]	BART Nation-wide
PM-Related Endpoints:			
Premature mortality[b]			
Adult, age 30 and over	17,000	17,000	8,200
Infant, age <1 year	36	38	19
Chronic bronchitis (adult, age 26 and over)	8,700	9,100	4,400
Nonfatal myocardial infarction (adults, age 18 and older)	22,000	23,000	11,000
Hospital admissions—respiratory (all ages)[c]	5,500	5,700	2,700
Hospital admissions—cardiovascular (adults, age >18)[d]	5,000	5,200	2,500
Emergency room visits for asthma (age 18 years and younger)	13,000	13,000	6,500
Acute bronchitis (children, aged 8–12)	19,000	20,000	10,000
Lower respiratory symptoms (children, aged 7–14)	230,000	240,000	120,000
Upper respiratory symptoms (asthmatic children, aged 9–18)	180,000	190,000	92,000
Asthma exacerbation (asthmatic children, aged 6–18)	290,000	310,000	150,000
Work loss days (adults, aged 18–65)	1,700,000	1,700,000	830,000
Minor restricted-activity days (adults, aged 18–65)	9,900,000	10,300,000	5,000,000
Ozone-Related Endpoints [e]			
Hospital admissions—respiratory causes (adult, 65 and older)	1,700	NE	NE
Hospital admissions—respiratory causes (children, under 2)	1,100	NE	NE
Emergency room visit for asthma (all ages)	280	NE	NE
Minor restricted-activity days (adults, aged 18–65)	690,000	NE	NE
School absence days	510,000	NE	NE

[a] Incidences are rounded to two significant digits. BART estimates reflect incidences for controls for the EGU source category only and a conservative (i.e, controls on most units) look at controls that states might choose to require on sources not subject to presumptive BART. For these reasons, the benefits and costs of BART in this appendix differ from Scenarios 1, 2, and 3 in this RIA.

[b] Premature mortality benefits associated with ozone are not quantified in the primary analysis. Adult premature mortality estimates are based on studies by Pope et al. (2002). Infant premature mortality estimates are based on studies by Woodruff, Grillo, and Schoendorf (1997).

[c] Respiratory hospital admissions for PM include admissions for COPD, pneumonia, and asthma.

[d] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

[e] Although ozone benefits are expected to occur for CAIR Plus BART in the Non-CAIR Region and BART nationwide, ozone benefits are estimated for the CAIR program only.

[f] These health effects incidences reflect estimates for the CAIR program (the promulgated CAIR and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware in CAIR). Modeling for CAIR assumes annual SO_2 and NO_x controls for Arkansas that is not a part of the CAIR program. Thus, the incidence estimates reported for CAIR are slightly overstated.

NE = Not estimated

Table E-3. Estimated Monetary Value in Reductions in Incidence of Health and Welfare Effects (in millions of 1999$)—2015[a,b,c]

Health Effect	Pollutant	CAIR Program[f]	CAIR Plus BART in the Non-CAIR Region[f]	BART Nationwide
Premature mortality[d]				
Adult >30 years				
3% discount rate	$PM_{2.5}$	$92,800	$96,300	$45,700
7% discount rate		78,100	81,100	38,400
Child <1 year		222	232	116
Chronic bronchitis (adults, 26 and over)	$PM_{2.5}$	3,340	3,510	1,690
Nonfatal acute myocardial infarctions				
3% discount rate	$PM_{2.5}$	1,850	1,920	905
7% discount rate		1,790	1,860	876
Hospital admissions for respiratory causes	$PM_{2.5}$, O_3	78.9	43.6	20.6
Hospital admissions for cardiovascular causes	$PM_{2.5}$	105	82.6	39.3
Emergency room visits for asthma	$PM_{2.5}$, O_3	3.56	3.62	1.79
Acute bronchitis (children, aged 8–12)	$PM_{2.5}$	7.06	7.41	3.68
Lower respiratory symptoms (children, 7–14)	$PM_{2.5}$	3.74	3.87	1.91
Upper respiratory symptoms (asthma, 9–11)	$PM_{2.5}$	4.77	4.69	2.30
Asthma exacerbations	$PM_{2.5}$	12.7	13.4	6.56
Work loss days	$PM_{2.5}$	219	209	101
Minor restricted-activity days (MRADs)	$PM_{2.5}$, O_3	543	528	256
School absence days	O_3	36.4	NE	NE
Worker productivity (outdoor workers, 18–65)	O_3	19.9	NE	NE
Recreational visibility, 81 Class I areas	$PM_{2.5}$	1,780	1,890	699
Monetized Total[e]				
Base estimate:				
3% discount rate		$101+B	$105+B	$49.5+B
7% discount rate		$86.3+B	$89.5+B	$42.2+B

[a] Monetary benefits are rounded to three significant digits for ease of presentation and computation. Benefit estimates relate to emissions reductions for the EGU source category only. Estimates represent nationwide benefits (with the exception of ozone and visibility) and are associated with NO_x and SO_2 reductions. Ozone benefits represent benefits for the eastern United States. Visibility estimates relate to Class I areas in the southeastern United States. BART estimates reflect benefits for controls for the EGU source category only and a conservative (i.e, controls on most units) look at controls that states might choose to require on sources not subject to presumptive BART. For these reasons, the benefits and costs of BART in this appendix differ from Scenarios 1, 2, and 3 in this RIA.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and 2015.

[c] Ozone benefits are estimated for the final CAIR. While ozone benefits are anticipated for CAIR plus BART in the Non-CAIR Region and BART nationwide, these ozone benefits were not estimated.

[d] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described earlier. Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003). Adult premature mortality estimates are based on studies by Pope et al. (2002). Infant premature mortality estimates are based upon studies by Woodruff, Grillo, and Schoendorf (1997).

[e] B represents the monetary value of health and welfare benefits not monetized. A detailed listing of unquantified benefits is provided in Table 1-4. Columnar totals may not add due to rounding.

[f] These benefits reflect estimates for the CAIR program (the promulgated CAIR and the proposal to include annual SO_2 and NO_x controls for New Jersey and Delaware in CAIR). Modeling for CAIR assumes annual SO_2 and NO_x controls for Arkansas that is not a part of the CAIR program. Thus, the benefit estimates reported for CAIR are slightly overstated.

NE = Not estimated

E.1 References

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APPENDIX F

SENSITIVITY ANALYSES OF SOME KEY PARAMETERS IN THE BENEFITS ANALYSIS

The primary analysis of benefits of the Clean Air Visibility Rule (CAVR) presented in Chapter 4 is based on our current interpretation of the scientific and economic literature. That interpretation requires judgments regarding the best available data, models, and modeling methodologies and the assumptions that are most appropriate to adopt in the face of important uncertainties. The majority of the analytical assumptions used to develop the primary estimates of benefits have been reviewed and approved by EPA's SAB. Both EPA and the SAB recognize that data and modeling limitations as well as simplifying assumptions can introduce significant uncertainty into the benefit results and that alternative choices exist for some inputs to the analysis, such as the mortality C-R functions.

This appendix supplements our primary estimates of benefits with a series of sensitivity calculations that use other sources of health effect estimates and valuation data for key benefits categories. These supplemental estimates examine sensitivity to both valuation issues (e.g., the appropriate income elasticity) and for physical effects issues (e.g., possible recovery from chronic illnesses). These supplemental estimates are not meant to be comprehensive. Rather, they reflect some of the key issues identified by EPA or commentors as likely to have a significant impact on total benefits. The individual adjustments in the tables should not simply be added together because (1) there may be overlap among the alternative assumptions and (2) the joint probability among certain sets of alternative assumptions may be low.

F.1 Premature Mortality—Long-Term Exposure

Reduction in the risk of premature mortality is the most important PM-related health outcome in terms of contribution to dollar benefits in the analysis for this rule. There are at least three important analytical assumptions that may significantly impact the estimates of the number and valuation of avoided premature mortalities. These include selection of the C-R function, structure of the lag between reduced exposure and reduced mortality risk, and effect thresholds. Results of this set of sensitivity analyses are presented in Table F-1.

Table F-1. Sensitivity of Benefits of Premature Mortality Reductions to Alternative Assumptions (Relative to Primary Estimate Benefits of the Final CAVR)

Description of Sensitivity Analysis		Avoided Incidences in 2015[a] Scenario 1	Avoided Incidences in 2015[a] Scenario 2	Avoided Incidences in 2015[a] Scenario 3	Value (million 1999$)[b] Scenario 1	Value (million 1999$)[b] Scenario 2	Value (million 1999$)[b] Scenario 3
Alternative Concentration-Response Functions for PM-Related Premature Mortality							
Pope/ACS Study (2002)[c]							
Lung Cancer		310	1,200	1,700	$1,800	$7,000	$9,900
Cardiopulmonary		65	250	360	$370	$1,500	$2,000
Krewski/Harvard Six-Cities Study		930	3,700	5,200	$5,300	$21,000	$30,000
Alternative Lag Structures for PM-Related Premature Mortality							
None	Incidences all occur in the first year	400	1,600	2,300	$2,500	$10,000	$15,000
8-year	Incidences all occur in the 8th year						
	3% discount rate	400	1,600	2,300	$2,100	$8,300	$12,000
	7% discount rate	400	1,600	2,300	$1,600	$6,300	$9,100
15-year	Incidences all occur in the 15th year						
	3% discount rate	400	1,600	2,300	$1,700	$6,700	$9,700
	7% discount rate	400	1,600	2,300	$1,000	$3,900	$5,700
Alternative Segmented	20 percent of incidences occur in 1st year, 50 percent in years 2 to 5, and 30 percent in years 6 to 20						
	3% discount rate	400	1,600	2,300	$2,200	$8,900	$13,000
	7% discount rate	400	1,600	2,300	$1,800	$7,100	$10,000

(continued)

Table F-1. Sensitivity of Benefits of Premature Mortality Reductions to Alternative Assumptions (Relative to Primary Estimate Benefits of the Final CAVR) (continued)

		Avoided Incidences in 2015[a]			Value (million 1999$)[b]		
	Description of Sensitivity Analysis	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 1**	**Scenario 2**	**Scenario 3**
5-Year Distributed	50 percent of incidences occur in years 1 and 2 and 50 percent in years 2 to 5						
	3% discount rate	400	1,600	2,300	$2,400	$9,700	$14,000
	7% discount rate	400	1,600	2,300	$2,300	$9,100	$13,000
Exponential	Incidences occur at an exponentially declining rate following year of change in exposure						
	3% discount rate	400	1,600	2,300	$2,400	$9,700	$14,000
	7% discount rate	400	1,600	2,300	$2,200	$8,900	$13,000
Alternative Thresholds							
	No Threshold (base estimate)	400	1,600	2,300	$2,300	$9,200	$13,000
	5 $\mu g/m^3$	400	1,600	2,200	$2,300	$9,200	$13,000
	10 $\mu g/m^3$	230	1,100	1,500	$1,300	$6,300	$8,600
	15 $\mu g/m^3$	0	130	170	$0	$750	$980
	20 $\mu g/m^3$	0	54	70	$0	$310	$400

[a] Incidences rounded to two significant digits.

[b] Dollar values rounded to two significant digits.

[c] Note that the sum of lung cancer and cardiopulmonary deaths will not be equal to the total all-cause death estimate. Some residual mortality is associated with long-term exposures to $PM_{2.5}$ that is not captured by the cardiopulmonary and lung cancer categories.

F.1.1 Alternative C-R Functions

Following the advice of the most recent EPA SAB-HES, we used the Pope et al. (2002) all-cause mortality model to derive our primary estimate of avoided premature mortality (EPA-SAB-COUNCIL-ADV-04-002, 2004). While the SAB-HES "recommends that the base case rely on the Pope et al. (2002) study and that EPA use total mortality concentration-response functions (C-R), rather than separate cause-specific C-R functions, to calculate total PM mortality cases," (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 2) they also suggested that "the cause-specific estimates can be used to communicate the relative contribution of the main air pollution related causes of death" (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 18). As such, in Table F-1 we provide the estimates of cardiopulmonary and lung cancer deaths based on the Pope et al. (2002) study.

In addition, the SAB-HES noted that the ACS cohort used in Pope et al. (2002) "has some inherent deficiencies, in particular the imprecise exposure data, and the nonrepresentative (albeit very large) population" (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 18). The SAB-HES suggests that while not necessarily a better study, the ACS is a prudent choice for the primary estimate. They go on to note that "the Harvard Six-Cities C-R functions are valid estimates on a more representative, although geographically selected, population, and its updated analysis has not yet been published. The Six-Cities estimates may be used in a sensitivity analysis to demonstrate that, with different but also plausible selection criteria for C-R functions, benefits may be considerably larger than suggested by the ACS study" (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 18). In previous advice, the SAB has noted that "the [Harvard Six-Cities] study had better monitoring with less measurement error than did most other studies" (EPA-SAB-COUNCIL-ADV-99-012, 1999). The demographics of the ACS study population (i.e., largely white and middle to upper middle-class) may also produce a downward bias in the estimated PM mortality coefficient, because a variety of analyses indicate that the effects of PM tend to be significantly greater among groups of lower socioeconomic status (Krewski et al., 2000), although the cause of this difference has not been identified. The Harvard Six-Cities study also covered a broader age category (25 and older compared to 30 and older in the ACS study). We emphasize that, based on our understanding of the relative merits of the two datasets, the Pope et al. (2002) ACS model based on mean $PM_{2.5}$ levels in 63 cities is the most appropriate model for analyzing the premature mortality impacts of CAVR. Thus it is used for our primary estimate of this important health effect.

F.1.2 Alternative Lag Structures

Over the last ten years, there has been a continuing discussion and evolving advice regarding the timing of changes in health effects following changes in ambient air pollution. It has been hypothesized that some reductions in premature mortality from exposure to ambient $PM_{2.5}$ will occur over short periods of time in individuals with compromised health status, but other effects are likely to occur among individuals who, at baseline, have reasonably good health that will deteriorate because of continued exposure. No animal models have yet been developed to quantify these cumulative effects, nor are there epidemiologic studies bearing on this question. The SAB-HES has recognized this lack of direct evidence. However, in early advice, they also note that "although there is substantial evidence that a portion of the mortality effect of PM is manifest within a short period of time, i.e., less than one year, it can be argued that, if no lag assumption is made, the entire mortality excess observed in the cohort studies will be analyzed as immediate effects, and this will result in an overestimate of the health benefits of improved air quality. Thus some time lag is appropriate for distributing the cumulative mortality effect of PM in the population" (EPA-SAB-COUNCIL-ADV-00-001, 1999, p. 9). In recent advice, the SAB-HES suggests that appropriate lag structures may be developed based on the distribution of cause-specific deaths within the overall all-cause estimate (EPA-SAB-COUNCIL-ADV-04-002, 2004). They suggest that diseases with longer progressions should be characterized by longer-term lag structures, while air pollution impacts occurring in populations with existing disease may be characterized by shorter-term lags.

A key question is the distribution of causes of death within the relatively broad categories analyzed in the long-term cohort studies. Although it may be reasonable to assume the cessation lag for lung cancer deaths mirrors the long latency of the disease, it is not at all clear what the appropriate lag structure should be for cardiopulmonary deaths, which include both respiratory and cardiovascular causes. Some respiratory diseases may have a long period of progression, while others, such as pneumonia, have a very short duration. In the case of cardiovascular disease, there is an important question of whether air pollution is causing the disease, which would imply a relatively long cessation lag, or whether air pollution is causing premature death in individuals with preexisting heart disease, which would imply very short cessation lags. The SAB-HES provides several recommendations for future research that could support the development of defensible lag structures, including using disease-specific lag models and constructing a segmented lag distribution to combine differential lags across causes of death (EPA-SAB-COUNCIL-ADV-04-002, 2004). The SAB-HES indicated support for using "a Weibull distribution or a simpler distributional form made up of several segments to cover the response mechanisms outlined above, given our lack of knowledge on the specific form of the distributions" (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 24). However, they noted that "an important question to be resolved is what the relative magnitudes of these segments should be, and how many of the acute effects are assumed to be included in the cohort effect estimate" (EPA-SAB-COUNCIL-ADV-04-002, 2004, p. 24-25). Since the publication of that report in March 2004, EPA has sought additional clarification from this committee. In its followup advice provided in December 2004, this SAB suggested that until additional research has been completed, EPA should assume a segmented lag structure characterized by 30 percent of mortality reductions occurring in the first year, 50 percent occurring evenly over years 2 to 5 after the reduction in $PM_{2.5}$, and 20 percent occurring evenly over the years 6 to 20 after the reduction in $PM_{2.5}$ (EPA-COUNCIL-LTR-05-001, 2004). The distribution of deaths over the latency period is intended to reflect the contribution of short-term exposures in the first year, cardiopulmonary deaths in the 2- to 5-year period, and long-term lung disease and lung cancer in the 6- to 20-year period. Furthermore, in their advisory letter, the SAB-HES recommended that EPA include sensitivity analyses on other possible lag structures. In this appendix, we investigate the sensitivity of premature mortality-reduction related benefits to alternative cessation lag structures, noting that ongoing and future research may result in changes to the lag structure used for the primary analysis.

In previous advice from the SAB-HES, they recommended an analysis of 0-, 8-, and 15-year lags, as well as variations on the proportions of mortality allocated to each segment in the segmented lag structure (EPA-SAB-COUNCIL-ADV-00-001, 1999; EPA-COUNCIL-LTR-05-001, 2004). The 0-year lag is representative of EPA's assumption in previous RIAs. The 8- and 15-year lags are based on the study periods from the Pope et al. (1995) and Dockery et al. (1993) studies, respectively.[1] However, neither the Pope et al. nor Dockery et al. studies assumed any lag structure when estimating the relative risks from PM exposure. In fact, the Pope et al. and Dockery et al. analyses do not supporting or refute the existence of a lag. Therefore, any lag structure applied to the avoided incidences estimated from either of these studies will be an assumed structure. The 8- and 15-year lags implicitly assume that all premature mortalities occur at the end of the study periods (i.e., at 8 and 15 years).

[1]Although these studies were conducted for 8 and 15 years, respectively, the choice of the duration of the study by the authors was not likely due to observations of a lag in effects but is more likely due to the expense of conducting long-term exposure studies or the amount of satisfactory data that could be collected during this time period.

In addition to the simple 8- and 15-year lags, we have added three additional sensitivity analyses examining the impact of assuming different allocations of mortality to the segmented lag of the type suggested by the SAB-HES. The first sensitivity analysis assumes that more of the mortality impact is associated with chronic lung diseases or lung cancer and less with acute cardiopulmonary causes. This illustrative lag structure is characterized by 20 percent of mortality reductions occurring in the first year, 50 percent occurring evenly over years 2 to 5 after the reduction in $PM_{2.5}$, and 30 percent occurring evenly over the years 6 to 20 after the reduction in $PM_{2.5}$. The second sensitivity analysis assumes the 5-year distributed lag structure used in previous analyses, which is equivalent to a three-segment lag structure with 50 percent in the first 2-year segment, 50 percent in the second 3-year segment, and 0 percent in the 6- to 20-year segment. The third sensitivity analysis assumes a negative exponential relationship between reduction in exposure and reduction in mortality risk. This structure is based on an analysis by Röösli et al. (2004), which estimates the percentage of total mortality impact in each period t as

$$\%\ \text{Mortality Reduction (t)} = \frac{\left[(RR-1)e^{-0.5t}+1\right]-1}{\sum_{t=1}^{\infty}\left[(RR-1)e^{-0.5t}+1\right]-1}. \qquad \text{(F.1)}$$

The Röösli et al. (2004) analysis derives the lag structure by calculating the rate constant (–0.5) for the exponential lag structure that is consistent with both the relative risk from the cohort studies and the change in mortality observed in intervention type studies (e.g., Pope, Schwartz, and Ranson [1992] and Clancy et al. [2002]). This is the only lag structure examined that is based on empirical data on the relationship between changes in exposure and changes in mortality. However, the analysis has not yet been peer reviewed and is thus not yet appropriate for adoption in the primary analysis.

The estimated impacts of alternative lag structures on the monetary benefits associated with reductions in PM-related premature mortality (estimated with the Pope et al. ACS impact function) are presented in Table F-1. These estimates are based on the value of statistical lives saved approach (i.e., \$5.5 million per incidence) and are presented for both a 3 and 7 percent discount rate over the lag period.

F.1.3 Thresholds

Although the consistent advice from EPA's SAB[2] has been to model premature mortality associated with PM exposure as a nonthreshold effect, that is, with harmful effects to exposed populations regardless of the absolute level of ambient PM concentrations. EPA's most recent $PM_{2.5}$ Criteria Document concludes that "the available evidence does not either support or refute the existence of thresholds for the effects of PM on mortality across the range of concentrations in the studies" (EPA, 2004, p. 9-44). Some researchers have hypothesized the presence of a threshold relationship. The nature of the hypothesized relationship is that there might exist a PM concentration level below which further reductions no longer yield premature mortality reduction benefits.[3]

We constructed a sensitivity analysis by assigning different cutpoints below which changes in $PM_{2.5}$ are assumed to have no impact on premature mortality. The sensitivity analysis illustrates how our estimates of the number of premature mortalities in the primary estimate might change under a range of alternative assumptions for a PM mortality threshold. If, for example, there were no benefits of reducing PM concentrations below the $PM_{2.5}$ standard of 15 $\mu g/m^3$, our estimate of the total number of avoided PM-related premature mortalities in 2015 from the primary analysis would be reduced by approximately 96 percent, from approximately 17,000 annually to approximately 700 annually. The recent NRC report stated that "for pollutants such as PM_{10} and $PM_{2.5}$, there is no evidence for any departure of linearity in the observed range of exposure, nor any indication of a threshold" (NRC, 2002, p. 109). At a threshold of 10 μg, approximately the 20th percentile of observed concentrations in the Pope et al. (2002) study, mortality impacts would be reduced by only 16 percent to approximately 14,000 annually. Another possible sensitivity analysis that we

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[2]The advice from the 2004 SAB-HES (EPA-SAB-COUNCIL-ADV-04-002) is characterized by the following: "For the studies of long-term exposure, the HES notes that Krewski et al. (2000) have conducted the most careful work on this issue. They report that the associations between $PM_{2.5}$ and both all-cause and cardiopulmonary mortality were near linear within the relevant ranges, with no apparent threshold. Graphical analyses of these studies (Dockery et al., 1993, Figure 3, and Krewski et al., 2000, page 162) also suggest a continuum of effects down to lower levels. Therefore, it is reasonable for EPA to assume a no threshold model down to, at least, the low end of the concentrations reported in the studies."

[3]The illustrative mortality results based on the pilot expert elicitation, described in Chapter 4 and more completely in Appendix B of the CAIR RIA presents the potential implications of assuming some probability of a threshold on the benefits estimate.

have not conducted at this time might examine the potential for a nonlinear relationship at lower exposure levels.[4]

One important assumption that we adopted for the threshold sensitivity analysis is that no adjustments are made to the shape of the C-R function above the assumed threshold. Instead, thresholds were applied by simply assuming that any changes in ambient concentrations below the assumed threshold have no impacts on the incidence of premature mortality. If there were actually a threshold, then the shape of the C-R function would likely change and there would be no health benefits to reductions in PM below the threshold. However, as noted by the NRC, "the assumption of a zero slope over a portion of the curve will force the slope in the remaining segment of the positively sloped concentration-response function to be greater than was indicated in the original study" and that "the generation of the steeper slope in the remaining portion of the concentration-response function may fully offset the effect of assuming a threshold." The NRC suggested that the treatment of thresholds should be evaluated in a formal uncertainty analysis.

F.1.4 Summary of Results

The results of these sensitivity analyses demonstrate that choice of effect estimate can have a large impact on benefits, potentially doubling benefits if the effect estimate is derived from the HEI reanalysis of the Harvard Six-Cities data (Krewski et al., 2000). Because of discounting of delayed benefits, the lag structure may also have a large impact on monetized benefits, reducing benefits by 30 to 50 percent (for 3 and 7 percent discount rates, respectively), if an extreme assumption that no effects occur until after 15 years is applied. However, for most reasonable distributed lag structures, differences in the specific shape of the lag function have relatively small impacts on overall benefits. For example, the overall impact of moving from a 5-year distributed lag to the segmented lag recommended by the SAB-HES in 2004 in the primary estimate is relatively modest, reducing benefits by approximately 5 percent when a 3 percent discount rate is used and 15 percent when a 7 percent discount rate is used. If no lag is assumed, benefits are increased by around 10 percent relative to the segmented lag with a 3 percent discount rate and 30 percent with a 7 percent discount rate. Benefits are more sensitive to assumptions regarding the potential for a threshold. The threshold sensitivity analysis indicates that for Scenario 2, over 68 percent of the premature mortality-related benefits are due to changes in $PM_{2.5}$ concentrations

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[4]The pilot expert elicitation discussed in Appendix B of the CAIR RIA provides some information on the impact of applying nonlinear and threshold-based C-R functions.

occurring above 10 $\mu g/m^3$, and around 8 percent are due to changes above 15 $\mu g/m^3$, the current $PM_{2.5}$ standard.

F.2 Alternative and Supplementary Estimates

We also examined how the value for individual endpoints or total benefits would change if we were to make a different assumption about specific elements of the benefits analysis. Specifically, in Table F-2, we show the impact of alternative assumptions about other parameters, including treatment of reversals in CB, valuation of recreational visibility at Class I areas outside of the study regions examined in the Chestnut and Rowe (1990a, 1990b) study, and valuation of household soiling damages.

Table F-2. Additional Parameter Sensitivity Analyses

	Alternative Calculation	Description of Estimate	Impact on Primary Benefit Estimate (million 2000$)		
			Least Stringent	Expected	Most Stringent
1	Treatment of reversals in CB	Instead of omitting cases of CB that reverse after a period of time, they are treated as being cases with the lowest severity rating. The number of avoided chronic CB for the least stringent Scenario 1 increases from 230 to 430 (87%). The increase for Scenario 2 is from 890 to 1,670 (87%). The increase for Scenario 3 is from 1,300 to 2,400 (85%).	+$34	+$130	+$190
2	Value of visibility changes in all Class I areas	Values of visibility changes at Class I areas in California, the Southwest, and the Southeast are transferred to visibility changes in Class I areas in other regions of the country.	+$54	+$120	+$200
3	Household soiling damage	Value of decreases in expenditures on cleaning are estimated using values derived from Manuel et al. (1983).	+$8	+$33	+$47

An important assumption related to chronic conditions is the possible reversal in CB incidences (row 1 of Table F-2). Reversals are defined as those cases where an individual reported having CB at the beginning of the study period but reported not having CB in follow-up interviews at a later point in the study period. Because chronic diseases are long-lasting or permanent by definition, if the disease abates in a shorter period of time it is not chronic. However, we have not captured the benefits of reducing incidences of bronchitis that are somewhere in between acute and chronic. Since chronic bronchitis may be assigned a range of severities, one way to address this is to treat reversals as cases of CB that are at the lowest severity level. These reversals of CB thus are assigned the lowest value for CB in this sensitivity analysis, rather than omitting reversals as is the case in the primary analysis.

The alternative calculation for recreational visibility (row 2 of Table F-2) is an estimate of the full value of visibility in the entire region affected by the CAIR emission reductions. The Chestnut and Rowe (1990a) study from which the primary valuation estimates are derived only examined WTP for visibility changes in the southeastern portion of the affected region. To obtain estimates of WTP for visibility changes in the northeastern and central portion of the affected region, we have to transfer the southeastern WTP values. This introduces additional uncertainty into the estimates. However, we have taken steps to adjust the WTP values to account for the possibility that a visibility improvement in parks in one region is not necessarily the same environmental quality good as the same visibility improvement at parks in a different region. This may be due to differences in the scenic vistas at different parks, uniqueness of the parks, or other factors, such as public familiarity with the park resource. To take this potential difference into account, we adjusted the WTP being transferred by the ratio of visitor days in the two regions.

The alternative calculation for household soiling (row 3 of Table F-2) is based on the Manuel et al. (1983) study of consumer expenditures on cleaning and household maintenance. This study has been cited as being "the only study that measures welfare benefits in a manner consistent with economic principals" (Desvousges, Johnson, and Banzhaf, 1998). However, the data used to estimate household soiling damages in the Manuel et al. study are from a 1972 consumer expenditure survey and as such may not accurately represent consumer preferences in 2015. EPA recognizes this limitation, but believes the Manuel et al. estimates are still useful in providing an estimate of the likely magnitude of the benefits of reduced PM household soiling.

F.3 Income Elasticity of Willingness to Pay

As discussed in Chapter 4, our estimates of monetized benefits account for growth in real GDP per capita by adjusting the WTP for individual endpoints based on the central estimate of the adjustment factor for each of the categories (minor health effects, severe and chronic health effects, premature mortality, and visibility). We examined how sensitive the estimate of total benefits is to alternative estimates of the income elasticities. Table F-3 lists the ranges of elasticity values used to calculate the income adjustment factors, while

Table F-3. Ranges of Elasticity Values Used to Account for Projected Real Income Growth[a]

Benefit Category	Lower Sensitivity Bound	Upper Sensitivity Bound
Minor Health Effect	0.04	0.30
Severe and Chronic Health Effects	0.25	0.60
Premature Mortality	0.08	1.00
Visibility[b]	—	—

[a] Derivation of these ranges can be found in Kleckner and Neumann (1999) and Chestnut (1997). COI estimates are assigned an adjustment factor of 1.0.

[b] No range was applied for visibility because no ranges were available in the current published literature.

Table F-4 lists the ranges of corresponding adjustment factors. The results of this sensitivity analysis, giving the monetized benefit subtotals for the four benefit categories, are presented in Table F-5.

Table F-4. Ranges of Adjustment Factors Used to Account for Projected Real Income Growth[a]

Benefit Category	Lower Sensitivity Bound	Upper Sensitivity Bound
Minor Health Effect	1.015	1.114
Severe and Chronic Health Effects	1.094	1.241
Premature Mortality	1.029	1.437
Visibility[b]	—	—

[a] Based on elasticity values reported in Table C-4, U.S. Census population projections, and projections of real GDP per capita.

[b] No range was applied for visibility because no ranges were available in the current published literature.

Table F-5. Sensitivity Analysis of Alternative Income Elasticities[a]

	Benefits in Millions of 1999$					
	Lower Sensitivity Bound			Upper Sensitivity Bound		
Benefit Category	Least Stringent	Expected	Most Stringent	Least Stringent	Expected	Most Stringent
Minor Health Effect	$20	$78	$110	$21	$83	$120
Severe and Chronic Health Effects	$140	$530	$750	$150	$580	$810
Premature Mortality[c]	$2,100	$8,200	$12,000	$2,900	$11,000	$16,000
Visibility[b]	$84	$240	$420	$84	$240	$420
Total Benefits[c]	$2,300	$9,100	$13,000	$3,200	$12,000	$18,000

[a] All estimates rounded to two significant digits.

[b] No range was applied for visibility because no ranges were available in the current published literature.

[c] Assuming a 3 percent discount rate for mortality benefits.

Consistent with the impact of mortality on total benefits, the adjustment factor for mortality has the largest impact on total benefits. The value of mortality in 2015 ranges from 90 percent to 130 percent of the primary estimate based on the lower and upper sensitivity bounds on the income adjustment factor. The effect on the value of minor and chronic health effects is much less pronounced, ranging from 98 percent to 105 percent of the primary estimate for minor effects and from 93 percent to 106 percent for chronic effects.

F.4 References

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APPENDIX G

RESULTS FOR TWO ADDITIONAL SCENARIOS APPLIED TO BART NON-EGU SOURCE CATEGORIES

We present below results for each BART source category affected by these two non-EGU scenarios ($2,000/ton and $3,000/ton, respectively). Cost and emission reductions are available for these scenarios; no benefits analyses were conducted for these scenarios. Results presented here reflect the use of 7 percent and 3 percent discount rates as part of the control strategy analysis for each scenario. There are no impacts for 8 of the 25 non-EGU source categories because there are no control measures available to reduce SO_2 and NO_x from these categories within AirControlNET. For seven source categories only, NO_x reductions take place in these analyses because there are no control measures available within AirControlNET at or below these cost/ton levels.

G.1 Summary of Results for Two Additional Non-EGU Scenarios

The two scenarios presented in this appendix are applied nationwide and are presented in detail in this appendix. These scenarios are meant to be illustrative of the potential alternatives that may be available to states as they consider what scenarios to include in their SIPs for non-EGU sources. These scenarios are also compliant with the requirement in OMB Circular A-4 to examine alternative levels of stringency as part of an RIA.

This section includes several summary tables in which the emission reductions and costs for these two non-EGU scenarios applied are shown by source category and also by the discount rate for the annualized costs. Table G-1 summarizes the SO_2 emission reductions for these BART non-EGU source categories using a discount rate of 7 percent and also showing results using a discount rate of 3 percent. In total, the scenarios applied in this analysis lead to nationwide SO_2 emission reductions ranging from 172,595 tons to 211,573 tons with costs at a 7 percent discount rate. These estimates represent a reduction of 14 to 18 percent from the 2015 baseline. These scenarios lead to SO_2 emission reductions ranging from 210,013 to 262,547 tons with costs at a 3 percent rate. These estimates represent a reduction of 17 to 22 percent from the 2015 baseline.

Table G-1. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons) $2,000/ton Scenario	$3,000/ton Scenario
Industrial boilers	420,782	7%	87,009	124,592
	420,782	3%	120,095	148,962
Petroleum refineries	199,483	7%	23,173	23,173
	199,483	3%	25,103	33,304
Kraft pulp mills	119,818	7%	0	0
	119,818	3%	0	3,196
Portland cement plants	116,835	7%	2,350	2,350
	116,835	3%	2,743	13,383
Hydrofluoric, sulfuric, and nitric acid plants	96,741	7%	35,358	36,753
	96,741	3%	36,753	36,753
Chemical process plants	47,700	7%	2,376	2,376
	47,700	3%	2,376	2,376
Iron and steel mills	23,541	7%	2,914	2,914
	23,541	3%	2,914	2,914
Coke oven batteries	9,815	7%	4,088	4,088
	9,815	3%	4,088	4,088
Sulfur recovery plants	59,766	7%	13,697	13,697
	59,766	3%	14,311	14,311
Primary aluminum ore reduction plants	47,552	7%	1,630	1,630
	47,552	3%	1,630	3,260
Lime kilns	9,373	7%	0	0
	9,373	3%	0	0

(continued)

Table G-1. SO_2 Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios—Reductions (tons) $2,000/ton Scenario	$3,000/ton Scenario
Glass fiber processing plants	2,170	7%	0	0
	2,170	3%	0	0
Municipal incinerators	284	7%	0	0
	284	3%	0	0
Coal cleaning plants	1,530	7%	0	0
	1,530	3%	0	0
Carbon black plants	41,853	7%	0	0
	41,853	3%	0	0
Phosphate rock processing plants	21	7%	0	0
	21	3%	0	0
Secondary metal production facilities	9,988	7%	0	0
	9,988	3%	0	0
Total	1,208,088	7%	172,595	211,573
	1,208,088	3%	210,013	262,547

Table G-2 summarizes the NO_x emission reductions. The nationwide NO_x emission reductions from applying these two scenarios range from 242,355 tons to 291,740 tons with costs at a 7 percent discount rate. These represent a reduction of 36 to 43 percent from the 2015 baseline. These scenarios lead to NO_x emission reductions ranging from 280,163 to 313,382 tons with costs at a 3 percent rate. These represent a reduction of 41 to 46 percent from the 2015 baseline.

Table G-2. NO_x Emissions and Emission Reductions for BART Source Categories in 2015

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios: $2,000/ton Scenario	Scenarios: $3,000/ton Scenario
Industrial boilers	217,063	7%	97,074	125,575
	217,063	3%	120,151	128,640
Petroleum refineries	86,566	7%	23,173	23,173
	86,566	3%	23,173	26,685
Kraft pulp mills	103,614	7%	50,221	60,985
	103,614	3%	56,466	64,521
Portland cement plants	120,567	7%	26,659	26,659
	120,567	3%	26,659	26,659
Hydrofluoric, sulfuric, and nitric acid plants	17,059	7%	11,283	11,283
	17,059	3%	11,283	11,283
Chemical process plants	72,577	7%	25,922	26,753
	72,577	3%	27,568	31,567
Iron and steel mills	20,963	7%	2,034	3,259
	20,963	3%	2,038	7,198
Coke oven batteries	10,389	7%	0	5,768
	10,389	3%	5,768	5,768
Sulfur recovery plants	651	7%	0	0
	651	3%	0	0
Primary aluminum ore reduction plants	1,676	7%	70	253
	1,676	3%	335	335
Lime kilns	12,849	7%	4,471	4,471
	12,849	3%	4,471	7,153

(continued)

Table G-2. NO_x Emissions and Emission Reductions for BART Source Categories in 2015 (continued)

BART Source Category	Baseline Emissions (tons)	Discount Rate	Scenarios: $2,000/ton Scenario	$3,000/ton Scenario
Glass fiber processing plants	6,677	7%	568	2,116
	6,677	3%	851	2,116
Municipal incinerators	1,656	7%	744	744
	1,656	3%	744	744
Coal cleaning plants	1,110	7%	0	511
	1,110	3%	511	511
Carbon black plants	4,645	7%	111	120
	4,645	3%	111	120
Phosphate rock processing plants	719	7%	0	45
	719	3%	0	48
Secondary metal production facilities	1,377	7%	25	25
	1,377	3%	34	34
Total	681,765	7%	242,355	291,740
	681,765	3%	280,163	313,382

Table G-3 summarizes the annualized costs associated with the two non-EGU scenarios. In total, the two scenarios applied in this analysis have annualized costs of $512.36 million to $706.26 million (1999$) with costs at a 7 percent discount rate and $507.23 million to $691.73 million (1999$) with costs at a 3 percent discount rate.

Table G-3. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$)

BART Source Category	Discount Rate	Scenarios: $2,000/ton Scenario	$3,000/ton Scenario
Industrial boilers	7%	241.5	412.1
	3%	255.0	337.4
Petroleum refineries	7%	71.1	71.1
	3%	71.1	81.2
Kraft pulp mills	7%	75.1	75.1
	3%	59.2	68.5
Portland cement plants	7%	29.6	29.6
	3%	28.7	56.6
Hydrofluoric, sulfuric, and nitric acid plants	7%	20.4	21.4
	3%	21.4	21.4
Chemical process plants	7%	40.5	40.5
	3%	30.4	40.1
Iron and Steel mills	7%	7.9	11.0
	3%	5.7	22.7
Coke oven batteries	7%	6.2	18.7
	3%	14.9	14.9
Sulfur recovery plants	7%	11.7	12.1
	3%	12.1	12.1
Primary aluminum ore reduction plants	7%	1.7	2.2
	3%	1.0	5.0
Lime kilns	7%	5.0	5.0
	3%	4.3	25.4

(continued)

Table G-3. Total Annualized Costs of Control for BART Source Categories in 2015 (million 1999$) (continued)

BART Source Category	Discount Rate	Scenarios: $2,000/ton Scenario	Scenarios: $3,000/ton Scenario
Glass fiber processing plants	7%	0.5	5.3
	3%	1.7	4.7
Municipal incinerators	7%	1.1	1.1
	3%	0.9	0.9
Coal cleaning plants	7%	0.0	1.0
	3%	0.8	0.8
Carbon black plants	7%	0.01	0.01
	3%	0.005	0.01
Phosphate rock processing plants	7%	0.01	0.01
	3%	0.01	0.01
Secondary metal production facilities	7%	0.04	0.04
	3%	0.01	0.01
Total	7%	$512.36	$706.26
	3%	$507.23	$691.73

Given the highly capital-intensive nature of the control measures included in these analyses, it is not unreasonable that a lower discount rate would lead to more application of these measures to reduce SO_2 and NO_x and vice versa. More sources would be controlled that may not be able to control if they face relatively high interest rates for capital outlays in pollution control equipment. At the $2,000/ton scenario, the emission reductions are higher with a 3 percent discount rate than a 7 percent discount rate because the lower discount rate leads to more sources having available controls under that scenario and the costs are fairly close. At $3,000/ton scenario, the annualized costs and reductions are relatively closer.

G.2 Results for Industrial Boilers

Table G-4 shows the SO_2 emissions reductions achieved in the analyses for each of these two scenarios. The table indicates that these two scenarios achieve incremental reductions from the 2015 baseline ranging from 21 to 30 percent given a 7 percent discount rate for the costs and from 29 to 35 percent for costs at a 3 percent discount rate.

Table G-4. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU Industrial Boilers[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	420,782	7%	333,773	87,009
	420,782	3%	300,687	120,095
$3,000/ton Scenario	420,782	7%	296,190	124,592
	420,782	3%	271,820	148,962

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-5 presents the NO_x baseline emissions and reductions for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline, ranging from 45 percent to 58 percent for costs at a 7 percent discount rate and from 55 to 59 percent for costs at a 3 percent discount rate.

Table G-5. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU Industrial Boilers

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	217,063	7%	119,989	97,074
	217,063	3%	96,912	120,151
$3,000/ton Scenario	217,063	7%	91,488	125,575
	217,063	3%	88,423	128,640

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-6 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from \$109 million to \$197 million with costs at a 7 percent discount rate, and from \$133 million to \$208 million with costs at a 3 percent discount rate. The accompanying average annualized cost-effectiveness results range from \$1,256 to \$1,580 per ton with costs at a 7 percent rate and from \$1,111 to \$1,398 per ton with costs at a 3 percent rate. In addition, the marginal costs between these scenarios are \$2,328 per ton with costs at a 7 percent discount rate and \$2,595 per ton with costs at a 3 percent discount rate.

Table G-6. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$109.3	$1,256	—
	3%	$133.4	$1,111	—
$3,000/ton Scenario	7%	$196.8	$1,580	$2,328
	3%	$208.3	$1,398	$2,595

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to more coal-fired units with lower sulfur contents and to oil-fired units that have lower sulfur contents than coal-fired units.

Table G-7 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from \$132.2 million to \$215.3 million with costs at a 7 percent rate and from \$121.6 million to \$129.1 million with costs at a 3 percent rate. The accompanying annualized average cost-effectiveness results range from \$1,360 to \$1,715 per ton with costs at a 7 percent rate and from \$1,012 to \$1,044 per ton with costs at a 3 percent rate. In addition, the marginal costs are \$2,929 per ton with costs at a 7 percent rate and \$2,684 per ton with costs at a 3 percent rate.

The average and marginal costs increase as the scenarios become more stringent as a result of additional application of SCR. SCR is the most expensive NO_x control device available to industrial boilers in our analysis, though they also have a high control level (80 percent).

Table G-7. 2015 Cost and Cost-Effectiveness Results for NO_x Control at BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$132.2	$1,360	—
	3%	$121.6	$1,012	—
$3,000/ton Scenario	7%	$215.3	$1,715	$2,929
	3%	$129.1	$1,044	$2,684

Table G-8 shows the total annualized costs for each scenario for controlling both SO_2 and NO_x.

Table G-8. 2015 Cost Results for SO_2 and NO_x Control at BART-Eligible Industrial Boilers

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$241.5
	3%	$255.0
$3,000/ton Scenario	7%	$412.1
	3%	$337.4

G.3 Results for Petroleum Refineries

Table G-9 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 12 percent with costs estimated at a 7 percent discount rate and from 13 percent to 17 percent for costs estimated at a 3 percent discount rate.

Table G-9. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Petroleum Refineries[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	199,483	7%	176,310	23,173
	199,483	3%	174,380	25,103
$3,000/ton Scenario	199,483	7%	176,310	23,173
	199,483	3%	166,179	33,304

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-10 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 27 percent for costs estimated at a 7 percent discount rate and from 27 to 34 percent for costs estimated at a 3 percent discount rate.

Table G-10. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Petroleum Refineries[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	86,566	7%	64,512	23,173
		3%	64,512	23,173
$3,000/ton Scenario	86,566	7%	64,512	23,173
		3%	59,881	26,685

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-11 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $28.5 million with costs at a 7 percent discount rate and range from $28.5 million to $43.9 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,231 per ton with costs at a 7 percent discount rate and range from $1,045 to $1,479 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are zero per ton with costs at a 7 percent discount rate and $3,025 per ton with costs at a 3 percent discount rate.

Table G-11. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$28.5	$1,231	—
	3%	$28.5	$1,045	—
$3,000/ton Scenario	7%	$28.5	$1,231	$0
	3%	$43.9	$1,479	$3,025

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to units such as fluid catalytic cracking units (FCCUs) with lower sulfur contents. As sulfur content of the fuel for a unit decreases, the cost per ton of control increases and vice versa.

Table G-12 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control cost is $42.6 million with costs at a 7 percent discount rate and ranges from $42.6 million to $52.7 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,930 per ton with costs at a 7 percent discount rate and range from $1,930 to $1,975 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are zero with costs at a 7 percent discount rate and $2,876 per ton with costs at a 3 percent discount rate.

The average and marginal costs rise as a result of additional process heaters having to apply LNB + SNCR.

Table G-12. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$42.6	$1,930	—
	3%	$42.6	$1,930	—
$3,000/ton Scenario	7%	$42.6	$1,930	$0
	3%	$52.7	$1,975	$2,876

Table G-13 shows the total annualized costs for controlling both SO_2 and NO_x.

Table G-13. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Petroleum Refineries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$71.1
	3%	$71.1
$3,000/ton Scenario	7%	$71.1
	3%	$81.2

G.4 Kraft Pulp Mills

Table G-14 shows the SO_2 emissions reductions achieved in the analyses for each of these scenarios. The table indicates that the scenarios achieve no incremental reductions from the 2015 baseline percent for costs at a 7 percent discount rate and from 0 to 3 percent for costs at a 3 percent discount rate.

Table G-15 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 48 percent to 59 percent for costs at a 7 percent discount rate and from 54 to 65 percent for costs at a 3 percent discount rate.

Table G-14. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Kraft Pulp Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	119,818	7%	119,818	0
	119,818	3%	119,818	0
$3,000/ton Scenario	119,818	7%	119,818	0
	119,818	3%	116,820	3,196

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-15. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Kraft Pulp Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	103,614	7%	53,393	50,221
	103,614	3%	47,148	56,466
$3,000/ton Scenario	103,614	7%	42,629	60,985
	103,614	3%	36,093	67,521

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-16 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $0 with costs at a 7 percent discount rate and range from $0 to $7.0 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 per ton with costs at a 7 percent discount rate (since there are no reductions) and from $0 to $2,189 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are zero with costs at a 7 percent discount rate and $2,189 per ton with costs at a 3 percent discount rate.

Table G-16. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$0.0	$0	—
	3%	$0.0	$0	—
$3,000/ton Scenario	7%	$0.0	$0	—
	3%	$7.0	$2,189	$2,189

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to units for which the application is more expensive.

Table G-17 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $75.1 million to $106.7 million with costs at a 7 percent discount rate and range from $59.2 million to $61.5 million with costs at a 3 percent rate. The accompanying annualized average cost-effectiveness results range from $1,496 to $1,749 per ton with costs at a 7 percent discount rate and from $1,048 to $1,069 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $3,344 per ton with costs at a 7 percent discount rate and $4,452 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect greater applications of SCR as the cost-per-ton cap rises, particularly for sulfite pulping recovery furnaces.

Table G-18 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table G-17. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
$2,000/ton Scenario	7%	$75.1	$1,496	—
	3%	$59.2	$1,048	—
$3,000/ton Scenario	7%	$106.7	$1,749	$3,344
	3%	$61.5	$1,069	$4,452

Table G-18. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Kraft Pulp Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$75.1
	3%	$59.2
$3,000/ton Scenario	7%	$75.1
	3%	$68.5

G.5 Results for Portland Cement Plants

Table G-19 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 2 percent for costs at a 7 percent discount rate and from 2 to 11 percent for costs at a 3 percent discount rate.

Table G-20 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 28 percent for costs at a 7 or a 3 percent discount rate.

Table G-19. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Portland Cement Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	116,835	7%	114,485	2,350
	116,835	3%	114,092	2,743
$3,000/ton Scenario	116,835	7%	114,485	2,350
	116,835	3%	103,452	13,383

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-20. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Portland Cement Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	120,567	7%	93,908	26,659
	120,567	3%	93,908	26,659
$3,000/ton Scenario	120,567	7%	93,908	26,659
	120,567	3%	93,908	26,659

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-21 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $4.6 million with costs at a 7 percent discount rate and range from $3.7 to $31.6 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,973 per ton with costs at a 7 percent discount rate and from $1,344 to $2,362 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are zero with costs at a 7 percent discount rate and $2,622 per ton with costs at a 3 percent discount rate.

Table G-21. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$4.6	$1,973	—
	3%	$3.7	$1,344	—
$3,000/ton Scenario	7%	$4.6	$1,973	—
	3%	$31.6	$2,362	$2,622

The costs and emission reductions reflect FGD scrubbers applied to all of these units. The average and marginal costs rise as a result of FGD scrubbers being applied to more units with lower sulfur content fuels.

Table G-22 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs are $25.0 million at either a 7 or a 3 percent discount rate for each scenario. The annualized average cost-effectiveness is $937 per ton. Since there is no difference in costs between these scenarios for NO_x control, the marginal costs are zero.

Table G-22. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
$2,000/ton Scenario	7%	$25.0	$937	—
	3%	$25.0	$937	—
$3,000/ton Scenario	7%	$25.0	$937	—
	3%	$25.0	$937	—

The average and marginal costs of control increase as more SCR applications take place as the cost-per-ton cap rises. These applications take the place of less expensive but less effective controls such as mid-kiln firing.

Table G-23 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table G-23. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Portland Cement Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$29.6
	3%	$28.7
$3,000/ton Scenario	7%	$29.6
	3%	$56.6

G.6 Results for Hydrofluoric, Sulfuric, and Nitric Acid Plants

Table G-24 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 35 to 38 percent for costs at a 7 percent discount rate and the same for costs at a 3 percent discount rate.

Table G-25 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of about 66 percent. The degree of impact varies little between scenarios and the discount rate of the costs.

Table G-26 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs range from $12.2 million to $14.1 million with costs at a 7 percent discount rate and are $14.1 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $345 to $385 per ton with costs at a 7 percent discount rate and are $385 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $1,362 per ton with costs at a 7 percent discount rate and zero (no reductions) with costs at a 3 percent discount rate.

Table G-24. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	96,741	7%	61,383	35,358
	96,741	3%	60,188	36,753
$3,000/ton Scenario	96,741	7%	60,188	36,753
	96,741	3%	60,188	36,753

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-25. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	17,059	7%	5,776	11,283
	17,059	3%	5,776	11,283
$3,000/ton Scenario	17,059	7%	5,776	11,283
	17,059	3%	5,776	11,283

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-26. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$12.2	$345	—
	3%	$14.1	$385	—
$3,000/ton Scenario	7%	$14.1	$385	$1,362
	3%	$14.1	$385	—

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce SO_2 emissions from these sources—increase sulfur conversion to meet the sulfuric acid NSPS (99.7 percent control).

Table G-27 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs are $8.2 million with costs at a 7 percent discount rate and $7.3 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $728 per ton with costs at a 7 percent discount rate and $647 per ton with costs at a 3 percent discount rate. The marginal costs are zero between these scenarios because no additional emission reductions occur.

Table G-27. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$8.2	$728	—
	3%	$7.3	$647	—
$3,000/ton Scenario	7%	$8.2	$728	—
	3%	$7.3	$647	—

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce NO_x emissions from these sources—SNCR applied to nitric acid manufacturing sources.

Table G-28 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

G.7 Results for Chemical Process Plants

Table G-29 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 7 percent for costs at either a 7 or a 3 percent discount rate.

Table G-28. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Hydrofluoric, Sulfuric, and Nitric Acid Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$20.4
	3%	$21.4
$3,000/ton Scenario	7%	$21.4
	3%	$21.4

Table G-29. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Chemical Process Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	47,700	7%	45,324	2,376
	47,700	3%	45,324	2,376
$3,000/ton Scenario	47,700	7%	45,324	2,376
	47,700	3%	45,324	2,376

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-30 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 36 percent to 37 percent for costs at a 7 percent discount rate and from 38 to 43 percent for costs at a 3 percent discount rate.

Table G-31 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $2.5 million with costs at a 7 percent discount rate and are $2.4 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,052 per ton with costs at a 7 percent discount rate and $1,013 per ton with costs at a 3 percent discount rate.

Table G-30. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Chemical Process Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	72,577	7%	46,655	25,922
	72,577	3%	45,009	27,568
$3,000/ton Scenario	72,577	7%	45,824	26,753
	72,577	3%	41,010	31,567

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-31. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$2.5	$1,052	—
	3%	$2.4	$1,013	—
$3,000/ton Scenario	7%	$2.5	$1,052	$1,052
	3%	$2.4	$1,013	$1,013

The costs and emission reductions reflect a major difference in the impacts between the two available control techniques: increase sulfur percentage conversion to meet the sulfuric acid NSPS (99.7 percent control) and FGD scrubbers.

Table G-32 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs are $38 million with costs at a 7 percent discount rate and from $28.0 million to $37.7 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,466 per ton with costs at a 7 percent discount rate and range from $1,015 per ton to $1,192 per ton with costs at a 3 percent discount rate. In addition, the marginal costs of the scenarios are zero (no additional reductions) with costs at a 7 percent discount rate and $4,348 per ton with costs at a 3 percent discount rate.

Table G-32. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$38.0	$1,466	—
	3%	$28.0	$1,015	—
$3,000/ton Scenario	7%	$38.0	$1,466	—
	3%	$37.7	$1,192	$4,348

Table G-33 shows the total annualized costs of each scenario for controlling both SO_2 and NO_x.

Table G-33. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Chemical Process Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$40.5
	3%	$30.4
$3,000/ton Scenario	7%	$40.5
	3%	$40.1

G.8 Results for Iron and Steel Mills

Table G-34 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 12 percent for costs at either a 7 or 3 percent discount rate.

Table G-35 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 5 to 41 percent for costs of either a 7 or 3 percent discount rate.

Table G-34. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Iron and Steel Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	23,541	7%	20,627	2,914
	23,541	3%	20,627	2,914
$3,000/ton Scenario	23,541	7%	20,627	2,914
	23,541	3%	20,627	2,914

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-35. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Iron and Steel Mills[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	20,963	7%	18,929	2,034
	20,963	3%	18,925	2,038
$3,000/ton Scenario	20,963	7%	17,704	3,259
	20,963	3%	13,765	7,198

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-36 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $5.3 million with costs at a 7 percent discount rate and $3.4 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,819 per ton with costs at a 7 percent discount rate and $1,165 per ton with costs at a 3 percent discount rate. Marginal costs are zero between the scenarios because there are no additional reductions from going to the $3,000 per ton scenario from the $2,000 per ton scenario.

Table G-36. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$5.3	$1,819	—
	3%	$3.4	$1,165	—
$3,000/ton Scenario	7%	$5.3	$1,819	—
	3%	$3.4	$1,165	—

Table G-37 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $2.6 million to $5.8 million with costs at a 7 percent discount rate and from $2.3 million to $15.0 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $1,302 to $1,770 per ton with costs at a 7 percent discount rate and from $1,109 to $2,271 per ton with costs at a 3 percent discount rate. The marginal costs are $2,953 per ton with costs at a 7 percent discount rate and $2,532 per ton with costs at a 3 percent discount rate.

The costs and emission reductions reflect a rise in the costs of control due to additional applications of LNB + either SNCR or SCR.

Table G-38 shows the total annualized costs for controlling both SO_2 and NO_x.

G.9 Results for Coke Oven Batteries

Table G-39 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 62 percent for costs at a 7 percent discount rate and from 0 to 57 percent for costs at a 3 percent discount rate.

Table G-37. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$2.6	$1,302	—
	3%	$2.3	$1,109	—
$3,000/ton Scenario	7%	$5.8	$1,770	$2,953
	3%	$15.0	$2,271	$2,532

Table G-38. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Iron and Steel Mills

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$7.9
	3%	$5.7
$3,000/ton Scenario	7%	$11.0
	3%	$22.7

Table G-39. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	9,815	7%	5,727	4,088
	9,815	3%	5,727	4,088
$3,000/ton Scenario	9,815	7%	5,727	4,088
	9,815	3%	5,727	4,088

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-40 shows the emissions reductions achieved in the analyses for each scenario for NO_x control. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 56 percent for costs at a 7 or 3 percent discount rate.

Table G-40. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Coke Oven Batteries[a]

Scenarios	2015 Baseline Emissions	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	10,389	10,389	0
	10,389	4,621	5,768
$3,000/ton Scenario	10,389	4,621	5,768
	10,389	4,621	5,768

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-41 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs rare $6.2 million with costs at a 7 percent discount rate and $4.0 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $1,517 per ton with costs at a 7 percent discount rate and from $1,074 per ton with costs at a 3 percent discount rate. The marginal costs are $1,517 per ton with costs at a 7 percent discount rate and $1,074 per ton with costs at a 3 percent discount rate.

Table G-41. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1990$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$6.2	$1,517	—
	3%	$4.0	$1,074	—
$3,000/ton Scenario	7%	$6.2	$1,517	$1,517
	3%	$4.0	$1,074	$1,074

The costs and emission reductions reflect application of only one control—vacuum carbonate plus a sulfur recovery plant but also differing SO_2 emissions levels at the affected coke oven batteries.

Table G-42 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $0 million to $12.5 million with costs at a 7 percent discount rate and are $10.9 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $0 to $2,167 per ton with costs at a 7 percent discount rate and are $1,898 per ton with costs at a 3 percent discount rate. In addition, the marginal costs are $2,167 per ton with costs at a 7 percent discount rate and zero with costs at a 3 percent discount rate.

Table G-42. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$0.0	$0	—
	3%	$10.9	$1,898	—
$3,000/ton Scenario	7%	$12.5	$2,167	$2,167
	3%	$10.9	$1,898	—

Table G-43 shows the total annualized costs for controlling both SO_2 and NO_x.

Table G-43. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Coke Oven Batteries

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$6.2
	3%	$14.9
$3,000/ton Scenario	7%	$18.7
	3%	$14.9

G.10 Results for Sulfur Recovery Plants

Table G-44 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 23 percent for costs at a 7 percent discount rate and 24 percent for costs at a 3 percent discount rate. The emission reductions are the same for each scenario because of the few controls available under these scenarios.

Table G-44. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Sulfur Recovery Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	59,766	7%	46,069	13,697
	59,766	3%	45,455	14,311
$3,000/ton Scenario	59,766	7%	46,069	13,697
	59,766	3%	45,455	14,311

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

There are no reductions of NO_x from sulfur recovery units under either of these scenarios.

Table G-45 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $11.6 million with costs at a 7 or a 3 percent discount rate. The accompanying annualized average cost-effectiveness results are $847 per ton with costs at a 7 percent discount rate and $849 per ton with costs at a 3 percent discount rate.

The costs and emission reductions are flat between the scenarios because there is only one control technique available to reduce SO_2 emissions from these sources—sulfur recovery and/or tail gas treatment.

Table G-46 shows the total annualized costs for controlling SO_2 from these sources.

Table G-45. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Sulfur Recovery Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$11.6	$847	—
	3%	$12.2	$849	—
$3,000/ton Scenario	7%	$11.6	$847	$847
	3%	$12.2	$849	$849

Table G-46. 2015 Cost Results for SO_2 Control at Non-EGU BART-Eligible Units at Sulfur Recovery Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$11.7
	3%	$12.1
$3,000/ton Scenario	7%	$12.1
	3%	$12.1

G.11 Results for Primary Aluminum Ore Reduction Plants

Table G-47 shows the SO_2 emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 3 to 7 percent for costs at a 7 or 3 percent discount rate.

Table G-48 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 4 to 15 percent with costs at a 7 percent discount rate and are 20 percent with costs at a 3 percent discount rate.

Table G-47. 2015 SO_2 Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	47,552	7%	45,922	1,630
	47,552	3%	45,922	1,630
$3,000/ton Scenario	47,552	7%	45,922	1,630
	47,552	3%	44,292	3,260

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-48. 2015 NO_x Baseline Emissions and Emission Reductions (in tons) for Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants[a]

Scenario	2015 Baseline Emissions	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	1,676	1,606	70
	1,676	1,341	335
$3,000/ton Scenario	1,676	1,423	253
	1,676	1,341	335

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in these source categories, both controlled and uncontrolled.

Table G-49 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for SO_2 control. The annualized control costs are $1.6 million with costs at a 7 percent discount rate and range from $1.0 million to $4.5 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $982 per ton with costs at a 7 percent discount rate and from $590 to $1,381 per ton with costs at a 3 percent discount rate. The marginal costs are zero with costs at a 7 percent discount rate and $2,147 per ton with costs at a 3 percent discount rate.

Table G-49. 2015 Cost and Cost-Effectiveness Results for SO_2 Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$1.6	$982	—
	3%	$1.0	$590	—
$3,000/ton Scenario	7%	$1.6	$982	—
	3%	$4.5	$1,381	$2,147

Table G-50 shows the annualized costs, resulting annualized average cost-effectiveness for each scenario, and marginal costs between each scenario for NO_x control. The annualized control costs range from $0.04 million to $0.6 million with costs at a 7 percent discount rate and from $0.04 to $0.5 million with costs at a 3 percent discount rate. The accompanying annualized average cost-effectiveness results range from $1,114 to $2,411 per ton with costs at a 7 percent discount rate and from $509 to $1,614 per ton with costs at a 3 percent discount rate. The marginal costs are $2,823 per ton with costs at a 7 percent discount rate and $1,764 per ton with costs at a 3 percent discount rate. The costs and NO_x emission reductions reflect LNB applications.

Table G-50. 2015 Cost and Cost-Effectiveness Results for NO_x Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$0.1	$1,114	—
	3%	$0.0	$509	—
$3,000/ton Scenario	7%	$0.6	$2,411	$2,823
	3%	$0.5	$1,614	$1,764

Table G-51 shows the total annualized costs for controlling both SO_2 and NO_x.

Table G-51. 2015 Cost Results for SO_2 and NO_x Control at Non-EGU BART-Eligible Units at Primary Aluminum Ore Reduction Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)
$2,000/ton Scenario	7%	$1.7
	3%	$1.0
$3,000/ton Scenario	7%	$2.2
	3%	$5.0

The next seven BART source categories only have NO_x controls applied to their affected units because there are no SO_2 emissions from BART-eligible units in these source categories that can be controlled at under $3,000 per ton. Hence, all the reductions and costs for the remaining source categories are only for NO_x, not SO_2.

G.12 Results for Lime Kilns

Table G-52 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the options achieve incremental reductions from the 2015 baseline ranging from 21 to 56 percent for costs at a 7 or 3 percent discount rate.

Table G-52. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Lime Kilns

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	12,849	7%	8,378	4,471
	12,849	3%	8,378	4,471
$3,000/ton Scenario	12,849	7%	8,378	4,471
	12,849	3%	5,696	7,153

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in this source category, both controlled and uncontrolled.

Table G-53 shows the annualized costs, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios are $5 million with costs at a 7 percent discount rate and range from $4.3 million to $25.4 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $1,118 per ton with costs at a 7 percent discount rate and ranges from $953 to $3,552 per ton with costs at a 3 percent discount rate. The marginal costs are zero (no additional reductions) with costs at a 7 percent discount rate and $7,867 per ton with costs at a 3 percent discount rate. These impacts reflect applications of SNCR.

Table G-53. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Lime Kilns

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$5.0	$1,118	—
	3%	$4.3	$953	—
$3,000/ton Scenario	7%	$5.0	$1,118	—
	3%	$25.4	$3,552	$7,867

G.13 Results for Glass Fiber Processing Plants

Table G-54 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the options achieve incremental reductions from the 2015 baseline ranging from 9 to 32 percent for costs at a 7 or 3 percent discount rate.

Table G-54. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Glass Fiber Processing Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	6,677	7%	6,109	568
	6,677	3%	5,826	851
$3,000/ton Scenario	6,677	7%	4,561	2,116
	6,677	3%	4,561	2,116

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table G-55 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from \$0.5 million to \$5.3 million with costs at a 7 percent discount rate and from \$1.7 million to \$4.7 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness ranges from \$937 to \$2,505 per ton with costs at a 7 percent discount rate and from \$1,972 to \$2,244 per ton with costs at a 3 percent discount rate.

Table G-55. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Glass Fiber Processing Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999\$)	Annualized Average Cost-Effectiveness (\$/ton)	Marginal Costs (\$/ton)
\$2,000/ton Scenario	7%	\$0.5	\$937	—
	3%	\$1.7	\$1,972	—
\$3,000/ton Scenario	7%	\$5.3	\$2,505	\$3,101
	3%	\$4.7	\$2,244	\$3,057

G.14 Results for Municipal Incinerators

The analysis of municipal incinerators (>250 tons per day burn refuse capacity) shows the results for each scenario. Table G-56 shows the NO_x emissions reductions achieved in the analysis for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of 45 percent for costs at a 7 or 3 percent discount rate.

Table G-56. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Municipal Incinerators[a]

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
\$2,000/ton Scenario	1,656	7%	912	744
	1,656	3%	912	744
\$3,000/ton Scenario	1,656	7%	912	744
	1,656	3%	912	744

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table G-57 shows the annualized costs, annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range is $1.1 million with costs at a 7 percent discount rate and $0.9 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $1,478 per ton with costs at a 7 percent discount rate and $1,207 per ton with costs at a 3 percent discount rate. The marginal costs are $1,478 per ton for reaching the $3,000 per ton scenario with costs at the 7 percent discount rate and $1,207 per ton at the 3 percent discount rate. The only available control measure for this source is SNCR.

Table G-57. 2007 Cost and Cost-Effectiveness Results for BART-Eligible Municipal Incinerators

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$1.1	$1,478	—
	3%	$0.9	$1,207	
$3,000/ton Scenario	7%	$1.1	$1,478	$1,478
	3%	$0.9	$1,207	$1,207

G.15 Results for Coal Cleaning Plants

Table G-58 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 0 to 46 percent for costs at a 7 or a 3 percent discount rate.

Table G-59 shows the annualized costs, annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0 to $1 million with costs at a 7 percent discount rate and $0.8 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $0 to $1,900 per ton with costs at a 7 percent discount rate and $1,534 per ton with costs at a 3 percent discount rate. Marginal costs are $1,900 per ton between the scenarios with costs at a 7 percent discount rate and are zero (no additional reductions) with costs at a 3 percent discount rate. Controls available to these sources are LNB and SNCR.

Table G-58. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Coal Cleaning Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	1,110	7%	1,110	0
	1,110	3%	599	511
$3,000/ton Scenario	1,110	7%	599	511
	1,110	3%	599	511

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table G-59. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Coal Cleaning Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$0.0	$0	—
	3%	$0.8	$1,534	—
$3,000/ton Scenario	7%	$1.0	$1,900	$1,900
	3%	$0.8	$1,534	—

G.16 Results for Carbon Black Plants

Table G-60 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline of about 2 percent for costs at a 7 or a 3 percent discount rate.

Table G-60. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Carbon Black Plants

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	4,645	7%	4,534	111
	4,645	3%	4,534	111
$3,000/ton Scenario	4,645	7%	4,525	120
	4,645	3%	4,525	120

[a] The 2015 baseline emissions estimate reflects emissions from all sources in this source category, both controlled and uncontrolled.

Table G-61 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios are about $0.01 million with costs at a 7 percent discount rate and about $0.006 million with costs at a 3 percent discount rate. The annualized average cost-effectiveness is $1,608 per ton with costs at a 7 percent discount rate and $1,495 per ton with costs at a 3 percent discount rate. Marginal costs are zero since there are no reductions between the scenarios. NO_x controls available to these sources are SNCR and SCR, and the cost per ton for these controls is fairly similar for these sources in this analysis.

Table G-61. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Carbon Black Plants

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Costs ($/ton)
$2,000/ton Scenario	7%	$0.0	$1,608	—
	3%	$0.0	$1,495	—
$3,000/ton Scenario	7%	$0.0	$1,608	—
	3%	$0.0	$1,495	—

G.17 Results for Secondary Metal Production Facilities

Table G-62 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 2 to 3 percent for costs at either a 7 or 3 percent discount rate.

Table G-62. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Secondary Metal Production Facilities

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	1,377	7%	1,352	25
	1,377	3%	1,343	34
$3,000/ton Scenario	1,377	7%	1,352	25
	1,377	3%	1,343	34

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in this source category, both controlled and uncontrolled.

Table G-63 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0.01 million to $0.04 million with costs at a 7 percent discount rate and the same with costs at a 3 percent discount rate. The annualized average cost-effectiveness ranges from $511 to $760 per ton with costs at a either a 3 or 7 percent discount rate. The marginal costs between the scenarios are zero since there are no additional reductions with increasing stringency.

Available NO_x controls are LNB and the more expensive LNB + SNCR.

G.18 Results for Phosphate Rock Ore Processing Facilities

Table G-64 shows the NO_x emissions reductions achieved in the analyses for each scenario. The table indicates that the scenarios achieve incremental reductions from the 2015 baseline ranging from 2 percent for costs at a 7 percent discount rate and from 2 to 47 percent for costs at a 3 percent discount rate.

Table G-63. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Secondary Metal Processing Facilities

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
$2,000/ton Scenario	7%	$0.0	$760	—
	3%	$0.0	$511	—
$3,000/ton Scenario	7%	$0.0	$760	—
	3%	$0.0	$511	—

Table G-64. 2015 NO_x Emission Reductions (in tons) for BART-Eligible Units at Phosphate Rock Ore Processing Facilities

Scenarios	2015 Baseline Emissions	Discount Rate	2015 Postcontrol Emissions	2015 Emission Reductions
$2,000/ton Scenario	719	7%	689	30
	719	3%	689	30
$3,000/ton Scenario	719	7%	689	30
	719	3%	689	30

[a] The 2015 baseline emissions estimate reflects emissions from all BART-eligible sources in this source category, both controlled and uncontrolled.

Table G-65 shows the annualized cost, resulting annualized average cost-effectiveness, and marginal costs for each scenario. The total annualized costs for these scenarios range from $0.01 million with costs at either a 7 or 3 percent discount rate. The annualized average cost-effectiveness is $760 per ton with costs at a either a 3 or 7 percent discount rate. The marginal costs between the scenarios are zero since there are no additional reductions with increasing stringency.

Table G-65. 2015 Cost and Cost-Effectiveness Results for BART-Eligible Units at Phosphate Rock Ore Processing Facilities

Scenarios	Discount Rate	Total Annualized Costs (million 1999$)	Annualized Average Cost-Effectiveness ($/ton)	Marginal Cost ($/ton)
$2,000/ton Scenario	7%	$0.0	$760	—
	3%	$0.0	$760	—
$3,000/ton Scenario	7%	0.0	760	—
	3%	0.0	760	—

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