Executive Summary

Background

Over the next decade, power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2) and mercury (Hg). At present, neither the future reduction requirements nor the complete timetable is known for any of these airborne emissions, and compliance planning is difficult. In response to the Clean Air Act Amendments of 1990 (CAAA90), operators are now in the process of making reductions in power plant emissions of SO_2 and NO_x. Phase II of the CAAA90 SO_2 reduction program—lowering allowable SO_2 emissions to an annual cap of 8.95 million tons—became effective on January 1, 2000, and more stringent NO_x emissions standards setting new emission limits for boilers also took effect in 2000.

States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, they may have to be further reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in NO_x and SO_2.

To reduce ozone formation, the U.S. Environmental Protection Agency (EPA) has promulgated a multi-State summer season cap on power plant NO_x emissions that would take effect in 2004. The fine particulate issue is still being studied, but reduced SO_2 emissions from power plants could be required as early as 2007 to address it. In addition, on December 15, 2000, the EPA decided that Hg emissions need to be reduced; and if the United States ratifies the Kyoto Protocol or a similar international greenhouse gas mitigation treaty, energy-related CO_2 emissions would also have to be reduced.

With changing standards on different timetables, comprehensive compliance planning is difficult. It can take several years to design, license, and construct new power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look far into the future to evaluate the economics of new investment decisions. Changing emission standards with different timetables add considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO_2 and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO_2 and NO_x may not be optimal if Hg and CO_2 emissions must also be reduced at a later date. Further complicating planning, some investments reduce multiple emissions simultaneously, such as SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners are wary of making investments that may prove unwise a few years hence.

Recently, plans have been proposed requiring coordinated multi-emission reductions. Several bills that have been introduced in Congress contain such provisions: S. 1369, the Clean Energy Act of 1999, introduced by Senator Jeffords; S. 1949, the Clean Power Plant and Modernization Act of 1999, introduced by Senator Leahy; H.R. 2900, the Clean Smokestacks Act of 1999, introduced by Congressman Waxman; H.R. 2645, the Consumer, Worker, and Environmental Protection Act of 1999, introduced by Congressman Kucinich; and H.R. 2980, the Clean Power Plant Act of 1999, introduced by Congressman Allen. Each of these bills contains provisions to reduce power plant emissions of NO_x, SO_2, CO_2 and Hg over the next decade. The bills use different approaches—traditional technology-specific emission standards, generation performance standards, explicit emission caps, or combinations of the three—but all call for significant emission reductions.

This report provides analysis of the potential impacts of efforts to reduce NO_x, SO_2, and CO_2 emissions from power plants. It examines the potential costs, to the energy sector and to consumers, of meeting the specified emission caps. It does not address the potential benefits of reduced emissions, such as might be associated with reduced health care costs, because EIA does not have expertise in this area. Readers should refer to the EPA and others for analysis of the potential benefits of emissions reductions. The bibliography for this report includes several studies that address the benefits of reducing emissions.[1]

The results in this report should not be interpreted as providing estimates of the electricity price changes and other impacts that would result from the enactment of the legislative proposals discussed previously. This analysis assumes a cap-and-trade mechanism, patterned after the system for SO_2 allowances implemented in CAAA90, for modeling all emission reductions in all

[1]Reports by Burtraw, Chestnut, and the EPA cited in the bibliography of this report include discussions of health benefits.

scenarios. The legislative proposals cited above include a variety of mechanisms to achieve emission reductions. Because the policy mechanisms used to implement emission reduction programs can affect compliance decisions and the resulting electricity prices, analysis of the specific policies called for in each proposal would be required to address their impacts.

The analysis was conducted at the request of the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform. In its request the Subcommittee asked the Energy Information Administration (EIA) to analyze the potential costs of various multi-emission reduction strategies to reduce the air emissions from electric power plants. The Subcommittee requested that EIA examine cases with alternative NO_x, SO_2, CO_2, and Hg emission reductions and renewable portfolio standard (RPS) requirements. The Subcommittee specified that the NO_x, SO_2, and CO_2 analysis should be done first if the Hg analysis could not be completed until a later date. This report examines NO_x, SO_2, and CO_2 emission limits. It does not address the potential impact of requirements to reduce power plant Hg emissions. A second volume, to be published in early 2001, will examine Hg emission limits and RPS requirements.

Cases Analyzed

A reference case and 10 basic analysis cases are examined in this report (Table ES1). Each case differs in terms of the specific emission caps imposed on the power sector and when they are imposed. Two NO_x cap cases look at the impacts of reducing power sector NO_x emissions to 75 percent below the level emitted in 1997. In the NO_x 2005 case, the cap on NO_x emissions is assumed to take effect in 2005; in the NO_x 2008 case, the cap is assumed to take effect in 2008. Two SO_2 cap cases assume similar reductions in power sector SO_2 emissions. Two CO_2 cap cases examine the impacts of reducing power sector CO_2 emissions to 1990 levels by 2005 or 2008 and, in both cases, further reducing them to 7 percent below that level, on average, between 2008 and 2012. Finally, four integrated cases examine the impacts of combining the various assumptions from the other cases for power sector emission caps on NO_x, SO_2, and CO_2. In each of the cases it is assumed that the emission reduction programs would operate as “cap and trade” programs, with power plant operators required to reduce their emissions or purchase sufficient allowances to cover them.

Four additional cases with alternative assumptions about the potential impacts of ongoing New Source Review (NSR) litigation against the owners of coal-fired power plants are also analyzed. The Subcommittee requested these cases in a letter dated September 25, 2000 (see Appendix J). The first case, referred to as the NSR 32 case, uses all of EIA’s reference case assumptions combined with the assumption that the owners of each of the 32 coal plants being sued for violating CAAA90 will be required to add emission control equipment to reduce NO_x and SO_2 by 2005 in order to continue operating them. The second case, referred to as the NSR All case, again uses all of EIA’s reference case assumptions but assumes that all coal-fired plants in addition to the 32 being sued will be required to have control equipment added to reduce NO_x and SO_2 emissions by 2010. The final two cases, referred to as the integrated NSR 32 and integrated NSR All cases, combine the assumptions of the NSR 32 and NSR All cases with those of the integrated 1990-7% 2005 case. In both of the NSR All cases it is assumed that the 32 plants currently being sued must still make their compliance decisions by 2005.

In addition to the cases requested by the Subcommittee, this report includes two cases that assume less stringent emission caps for SO_2 and CO_2 and an integrated case that combines the less stringent targets (Table ES2). These cases were analyzed to examine the sensitivity of the results to the emission targets chosen. The emission cap in the SO_2 sensitivity case was set halfway between the estimated emissions for 2000 and the caps requested by the Subcommittee—roughly a 50-percent reduction from 1997 levels, rather than the 75-percent reduction specified by the Subcommittee. For CO_2 a similar approach was used. The CO_2 cap in 2005 in the CO_2 sensitivity case was set to halfway between the estimated emissions in 2000 and the 1990 level. The cap was then lowered further over the 2008 to 2012 time period, to halfway between the estimated 2000 emissions and 7 percent below the 1990 level. Using this approach, the CO_2 cap in 2005 in the CO_2 sensitivity case was assumed to be 12 percent above 1990 levels, before declining to 7 percent above 1990 levels over the 2008 to 2012 time period.

Analysis Approach

In this analysis, it is assumed that the programs set up to reduce NO_x, SO_2, and CO_2 emissions from power plants will operate like the existing SO_2 program established in Title IV of CAAA90. Marketable emission allowances or permits are assumed to be allocated to power plant operators at no cost (and therefore no money would be collected by the government). No assumption is made about the specific allocation methodology to be used, other than that it is a fixed allocation (does not change from year to year) and the total amount allocated equals the national emission targets for NO_x, SO_2, and CO_2. Holders of allowances are assumed to be free to use them to cover emissions from their own power plants or sell them to others who need them.

Table ES1. Analysis Cases

Case Name	Electric Power Sector Emission Caps: NO_x	SO_2	CO_2	Hg	Compliance Dates	RPS Requirement
NO_x Cap Cases						
NO_x 2005	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2005	None
NO_x 2008	75% below 1997 level	CAAA90 cap	None	None	Start 2002; meet target by 2008	None
SO_2 Cap Cases						
SO_2 2005	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2005	None
SO_2 2008	CAAA90 standards and NO_x SIP Call	75% below 1997	None	None	Start 2002; meet target by 2008	None
CO_2 Cap Cases						
CO_2 1990-7% 2005	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2005; 7% below 1990 level in 2008-2012	None
CO_2 1990-7% 2008	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% below 1990 level	None	Start 2002; 1990 level by 2008; 7% below 1990 level in 2008-2012	None
Integrated Cases						
Integrated 2005	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2005	None
Integrated 1990-7% 2005	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; CO_2 1990 level by 2005; 7% below 1990 level in 2008-2012	None
Integrated 2008	75% below 1997 level	75% below 1997 level	1990 level	None	Start 2002; meet target by 2008	None
Integrated 1990-7% 2008	75% below 1997 level	75% below 1997 level	7% below 1990 level	None	Start 2002; NO_x/SO_2 targets by 2008; CO_2 1990 level by 2008, 7% below 1990 level in 2008-2012	None

Notes: CAAA90 cap refers to the 8.95 million ton SO_2 cap established in Title IV of the Clean Air Act Amendments of 1990. CAAA90 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target of 7 percent below 1990 levels is between 2008 and 2012. The cap is then held constant at that level through 2020. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: See requesting letters in Appendix J.

The analysis presented in this report should be seen as an examination of the steps that power suppliers and consumers might take to meet the emission caps specified by the Subcommittee. The specific design of the cases—timing, emission cap levels, policy instruments used, etc.—are important and should be kept in mind when the results are reviewed. For example, it is assumed that the market participants—power suppliers, consumers, and coal, gas, and renewable fuel suppliers—would become aware of the impending emission caps before their target dates and begin to take action to meet the future targets.

If the timing of market response were different, the results would change. In previous EIA studies that looked at alternative program start dates for imposing a CO_2 emissions cap (or carbon cap), an earlier start date and longer phase-in period were found to smooth the transition of the economy to the longer run target.[2]

In addition, this study is not intended to be an analysis of any of the specific congressional bills that have been proposed, and the impacts estimated here should not be considered as indicating the consequences of specific legislative proposals. All the proposals include

[2]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998); and *Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol*, SR/OIAF/99-02 (Washington, DC, July 1999).

Table ES2. Assumed Emission Caps for Electricity Generators in Sensitivity Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
SO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	None	None	Start 2002; meet target by 2005	None
CO_2 Sensitivity	CAAA90 standards and NO_x SIP Call	CAAA90 cap	7% above 1990 level	None	Start 2002; reach 10% above 1990 CO_2 level in 2005 and 7% above 1990 level in 2008-2012	None
Integrated Sensitivity	CAAA90 standards and NO_x SIP Call	50% below 1997 level	7% above 1990 level	None	Start 2002; NO_x/SO_2 targets by 2005; for CO_2, reach 10% above 1990 level in 2005 and 7% above 1990 level in 2008-2012	None

Notes: CAAA90 cap refers to the 8.95 million ton SO_2 cap established in Title IV of the Clean Air Act Amendments of 1990. CAAA90 standards refer to the boiler emission standards for NO_x established in Title V of the Clean Air Act Amendments of 1990. NO_x SIP Call refers to the 19-State summer season cap on NO_x emissions to begin in 2004. The time period for reaching the CO_2 target 7 percent above 1990 levels is between 2008 and 2012. The emission caps are phased in gradually until the target cap is met on the specified date.

Source: Office of Integrated Analysis and Forecasting.

provisions other than the emission caps studied in this analysis. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be required because of ongoing environmental programs whose requirements currently are not specified but for which legislation has been promulgated.

Key Findings

- When emissions caps are examined individually, power companies are projected to invest primarily in emission control equipment to comply with the NO_x and SO_2 caps; however, to comply with the CO_2 cap they are expected to shift dramatically away from coal to natural gas and, to a lesser extent, renewables.
- The stringency of the emission targets influences the projected impact on electricity and natural gas prices.
- The impacts of meeting the NO_x and SO_2 caps are not projected to have a large effect on electricity prices—generally 1 percent or so above the prices expected in the reference case.
- The projected price impacts of meeting the CO_2 cap are much larger than those of meeting the NO_x and SO_2 caps.
- The CO_2 allowance prices (expressed in dollars per metric ton carbon equivalent) projected in this analysis are generally lower than those projected in studies of efforts to meet the target from the Kyoto Protocol over the whole economy rather than just in the power sector.
- When emissions caps are examined together, actions taken to meet the CO_2 cap are expected to overshadow those taken to reduce NO_x and SO_2 emissions.
- Using an integrated approach—setting caps on power sector NO_x, SO_2, and CO_2 emissions at the same time—is projected to lead to lower total costs than addressing each emission one at a time.
- If existing coal plants are required to add emission control equipment, NO_x and SO_2 emissions would be dramatically reduced.
- There is considerable uncertainty about whether the changes projected in this analysis could be accomplished in the relatively short time periods assumed—particularly to meet 2005 emission targets.

Electricity Market Impacts

The emission caps specified by the Subcommittee are projected to affect all aspects of the electricity business, especially in cases that include a CO_2 cap. The caps affect capacity planning and retirement decisions, investments in emission control equipment, fuel choices for generation, and electricity prices. One issue that affects all the cases, especially those with 2005 compliance dates, is whether the time lines proposed are realistic. To meet the emission caps specified by the Subcommittee, electricity markets together with their associated fuel markets—coal, natural gas, renewables, and other fuels—would need to make rapid changes, which may be difficult to accomplish in a short time.

Compliance Decisions

In all the analysis cases, emission caps are projected to have significant impacts on coal-fired power plants, generally leading to lower utilization rates and earlier retirements of existing coal plants than those projected in the reference case, especially when CO_2 emission caps are assumed. In the NO_x and SO_2 cap cases only a small number of coal plants are expected to be retired; the vast majority are projected to control emissions and continue operating. The main compliance option in the NO_x and SO_2 cap cases is the addition of emission control equipment: selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment to reduce NO_x emissions, and flue gas desulfurization equipment (scrubbers) to reduce SO_2 (Table ES3). As expected, the projected need for emission control equipment is sensitive to the assumptions about the levels at which emissions would be capped.

The amount of emission control equipment projected to be needed in the NO_x and SO_2 cap cases, particularly those with 2005 compliance dates, could cause system operation problems under some conditions. Typically, when new emissions controls are added, particularly SCRs, a plant must be off line for a time so that final connections can be made. The amount of capacity to which emission control equipment is expected to be added in these cases could lead to a concentration of connection outages in the few years just before the emission caps take effect. This could lead to a large amount of capacity being temporarily unavailable, increasing the possibility of short-term imbalances of supply and demand caused by unexpected demand spikes and/or unplanned outages of other units. Such imbalances could have significant impacts on wholesale power prices, and in extreme cases they could lead to power outages.

Several recent studies have looked into whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the CAAA90 NO_x State implementation plan (SIP) call might lead to system operational and reliability problems. If a decision were made to pursue the stringent NO_x and SO_2 caps analyzed in this report without a CO_2 reduction requirement, additional analysis of this issue would be needed.

In the SO_2 sensitivity case, the less stringent emission caps examined are projected to lead to a lower amount of capacity to which emission control equipment would be added, as compared with the amounts expected in the more stringent cases. The need for new SO_2 emission control equipment is projected to be much lower in the integrated sensitivity case, because the CO_2 cap causes enough switching from coal to gas to allow the electricity generation sector to meet the assumed SO_2 caps without adding much additional emission control equipment.

Table ES3. Projected Additions of Power Plant Emission Controls, 1999-2020
(Gigawatts)

Analysis Case	Emission Control Technology		
	SNCR	SCR	FGD
Reference	39	90	15
NO_x Cap Cases			
NO_x 2005	59	252	14
NO_x 2008	60	243	15
SO_2 Cap Cases			
SO_2 2005	32	117	128
SO_2 2008	27	124	130
SO_2 Sensitivity	36	96	52
CO_2 Cap Cases			
CO_2 1990-7% 2005	16	42	0
CO_2 1990-7% 2008	22	54	0
CO_2 Sensitivity	26	54	0
Integrated Cases			
Integrated 2005	56	157	21
Integrated 1990-7% 2005	49	147	17
Integrated 2008	48	123	23
Integrated 1990-7% 2008	38	108	18
Integrated Sensitivity	26	60	8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction. FGD = flue gas desulfurization (scrubbers).
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

Compliance decisions made by power plant operators and their impacts on generation costs and consumer electricity prices could be very different if the various emissions caps were imposed together or one at a time on different schedules. Power plant owners would be expected to rely heavily on investments in emission control technologies to comply with the NO_x and SO_2 caps if they were introduced individually; but if the NO_x, SO_2, and CO_2 caps were combined, heavy investments in NO_x and SO_2 emission control equipment would not be expected to be part of the most economical compliance strategy. Rather, many of the coal-fired power plants where such equipment might have been added are projected to be retired if a stringent CO_2 cap is imposed. New natural gas plants, and to a lesser extent renewable plants, are projected to be built, and the lives of existing nuclear plants are projected to be extended.

The projected impacts on capacity expansion and retirement, fuel use (generation), and consumer electricity prices are similar in the CO_2 cap and integrated cases (Table ES4). When the three emission caps are assumed to be imposed in concert, efforts to comply with the CO_2 cap are projected to have the most significant effect, as can be seen by comparing the results for the CO_2 cap and integrated cases. When a CO_2 cap is assumed, large investments in NO_x and SO_2 emission control equipment, beyond the levels added in the reference case, are not expected to be needed, because the amount of coal-fired capacity projected to be retired in order to meet the hypothesized CO_2 cap is sufficient to meet the NO_x and SO_2 caps with little additional effort.

The move from coal to natural gas in the cases with CO_2 caps is expected to be significant (Figure ES1). Increased generation from natural gas is projected to be the primary compliance option in the cases that include CO_2 caps. By 2010, natural gas consumption for electricity generation is projected to be as high as 11.8 trillion cubic feet in the integrated cases, much higher than the 6.7 trillion cubic feet projected in the reference case. The share of generation coming from gas is projected to grow from 15 percent in 1999 to as high as 45 percent in 2010 and 56 percent in 2020 in the integrated cases. Again, electricity markets and the associated markets for coal, natural gas, renewables, and other fuels would need to make rapid changes, which could prove difficult to accomplish in a short time. In addition, increasing dependence on natural gas for electricity production could lead to greater volatility in electricity prices as they move with changes in gas prices.

Increased generation from renewables is expected to play a role in cases with CO_2 caps, but their contribution is much smaller than that of natural gas. In cases without a CO_2 cap, projected additions of renewable generating capacity are virtually unchanged from those projected in the reference case. When a CO_2 cap is assumed, carbon allowance fees are expected to increase the costs of building and operating generators using fossil fuels, making renewable technologies more economically attractive. Geothermal, biomass, and wind are expected to show the largest generation increases in the cases with CO_2 caps, and total generation from nonhydroelectric renewables is expected to provide as much as 8 percent of total electricity generation in 2020 in the integrated cases, substantially higher than the 3-percent share projected in the reference case.

Cost and Price Impacts

Power plant operators are expected to incur significant costs to comply with the emission caps in the NO_x and SO_2 cap cases, but they may not be able to pass all the costs on to consumers through higher electricity prices. In competitive markets, cost increases do not directly translate into price increases. Electricity generation prices in competitive markets are set by the operating costs of the marginal plant—the plant running with the highest cost during a given period. Cost increases that do not affect the operating costs of the marginal plant will not affect prices. In many cases, adding emission control equipment to a plant involves mainly capital expenditures and leads to little change in the plant's operating costs. In addition, many of the plants to which the controls would be added are not price-setting plants. As a result, the addition of emission control equipment would not always lead directly to higher electricity prices, even though significant investments would be made.

In the NO_x cap cases, power plant operators are projected to spend more than $17 billion to add emission control equipment, much higher than the $10 billion expected in the reference case. These expenditures represent the capital costs of installing the equipment. The increased costs for power plant operators, if incurred in generation markets with cost-of-service regulation, would be passed on directly to consumers in electricity prices. In competitively priced markets, however, the higher costs would be passed on to consumers only if they increased the operating costs of the generating plants that set the market price for power. For example, if SCR equipment were added to reduce NO_x emissions from a coal plant that did not set the market price for power, the costs of installing and operating the equipment would not be passed on to consumers as long as the plant's operating costs remained below the market price.

In the SO_2 cap cases, SO_2 allowance prices are projected to rise dramatically, reaching as high as $735 per ton in 2010 and $1,125 per ton in 2020, because of the need to add scrubbers to plants using relatively low-sulfur coal. In competitive electricity markets, however, the costs of adding and operating scrubbers would not affect the

Table ES4. Summary of Projections, 2010 and 2020

Analysis Case	Coal-Fired Electricity Generation (Billion Kilowatthours)	Natural-Gas-Fired Electricity Generation (Billion Kilowatthours)	Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Electricity Price (1999 Cents per Kilowatthour)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenues (Billion 1999 Dollars)
2010 Results							
Reference	2,284	1,123	NA	2.68	5.9	927	243
NO_x Cap Cases							
NO_x 2005	2,237	1,161	NA	2.68	5.9	933	245
NO_x 2008	2,237	1,164	NA	2.72	5.9	934	245
SO_2 Cap Cases							
SO_2 2005	2,198	1,195	NA	2.67	5.9	937	246
SO_2 2008	2,259	1,146	NA	2.63	5.9	929	243
SO_2 Sensitivity	2,237	1,169	NA	2.72	5.9	932	244
CO_2 Cap Cases							
CO_2 1990-7% 2005	1,113	1,859	143	4.36	8.3	1,126	319
CO_2 1990-7% 2008	1,055	1,922	139	4.13	8.2	1,126	318
CO_2 Sensitivity	1,454	1,609	102	3.48	7.6	1,070	297
Integrated Cases							
Integrated 2005	1,276	1,746	114	3.83	7.9	1,094	306
Integrated 1990-7% 2005	1,135	1,839	134	4.33	8.4	1,128	320
Integrated 2008	1,261	1,789	108	3.75	7.7	1,087	303
Integrated 1990-7% 2008	1,067	1,935	126	4.16	8.2	1,121	316
Integrated Sensitivity	1,444	1,617	101	3.52	7.6	1,074	299
2020 Results							
Reference	2,370	1,866	NA	3.14	6.0	993	288
NO_x Cap Cases							
NO_x 2005	2,335	1,894	NA	3.18	6.0	996	289
NO_x 2008	2,328	1,902	NA	3.15	6.0	995	289
SO_2 Cap Cases							
SO_2 2005	2,329	1,911	NA	3.20	6.0	995	289
SO_2 2008	2,339	1,901	NA	3.25	6.1	1,005	293
SO_2 Sensitivity	2,331	1,904	NA	3.17	6.0	996	289
CO_2 Cap Cases							
CO_2 1990-7% 2005	885	2,704	141	4.22	7.9	1,149	347
CO_2 1990-7% 2008	876	2,748	139	4.38	7.9	1,153	350
CO_2 Sensitivity	1,191	2,591	112	4.00	7.5	1,121	337
Integrated Cases							
Integrated 2005	1,000	2,752	113	4.04	7.6	1,127	338
Integrated 1990-7% 2005	852	2,774	130	4.30	7.8	1,146	345
Integrated 2008	998	2,746	116	4.32	7.7	1,140	343
Integrated 1990-7% 2008	834	2,816	129	4.42	7.9	1,148	347
Integrated Sensitivity	1,159	2,623	115	4.06	7.6	1,129	339

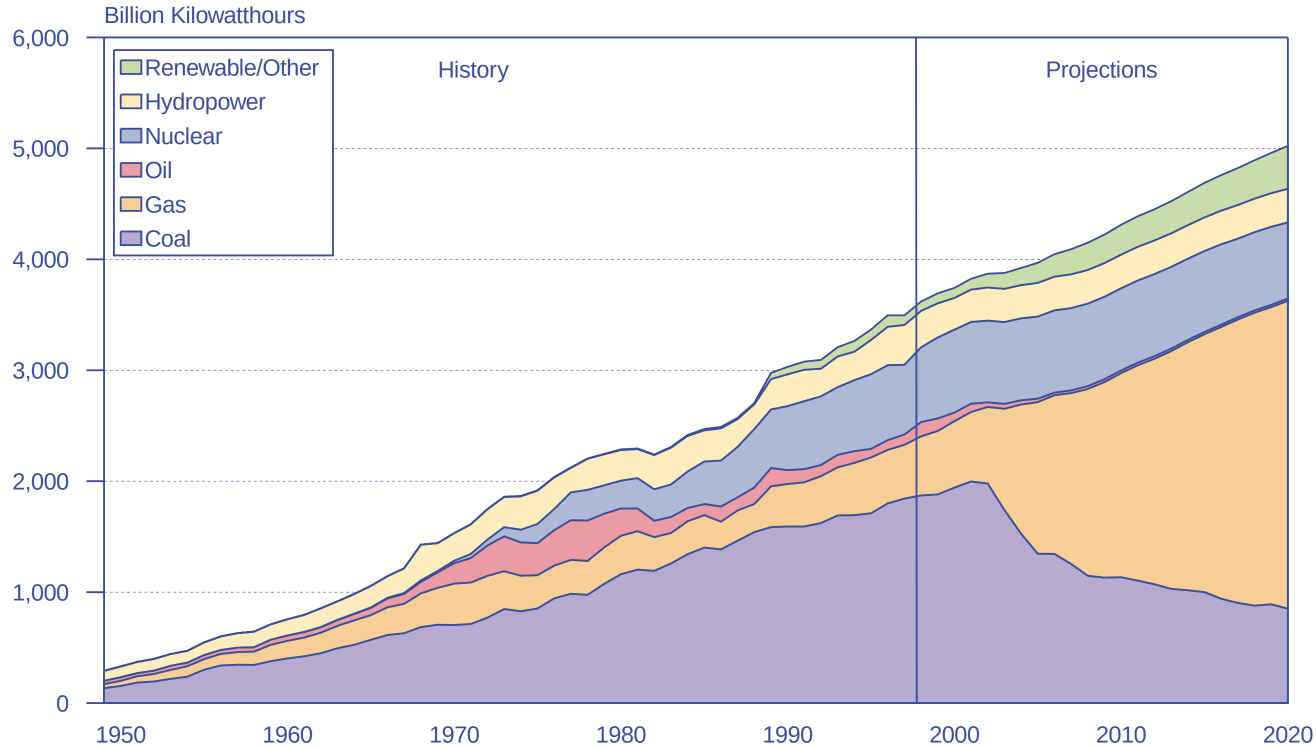
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

price of electricity if the plant did not set the market price. In such instances, the scrubber costs would reduce the profitability of the plant, but it might still remain economical to operate the facility.

The projections for SO_2 allowance prices are sensitive to variations in the assumed SO_2 emission target. SO_2 allowance prices are projected to be $735 per ton in 2010 in the SO_2 2005 case, but they are projected to be less than half that value, $300 per ton, in the SO_2 sensitivity case. The differences in the projections result from the less stringent emission target assumed in the SO_2 sensitivity case, which reduces the expected need to add emission controls at plants using relatively low-sulfur coal.

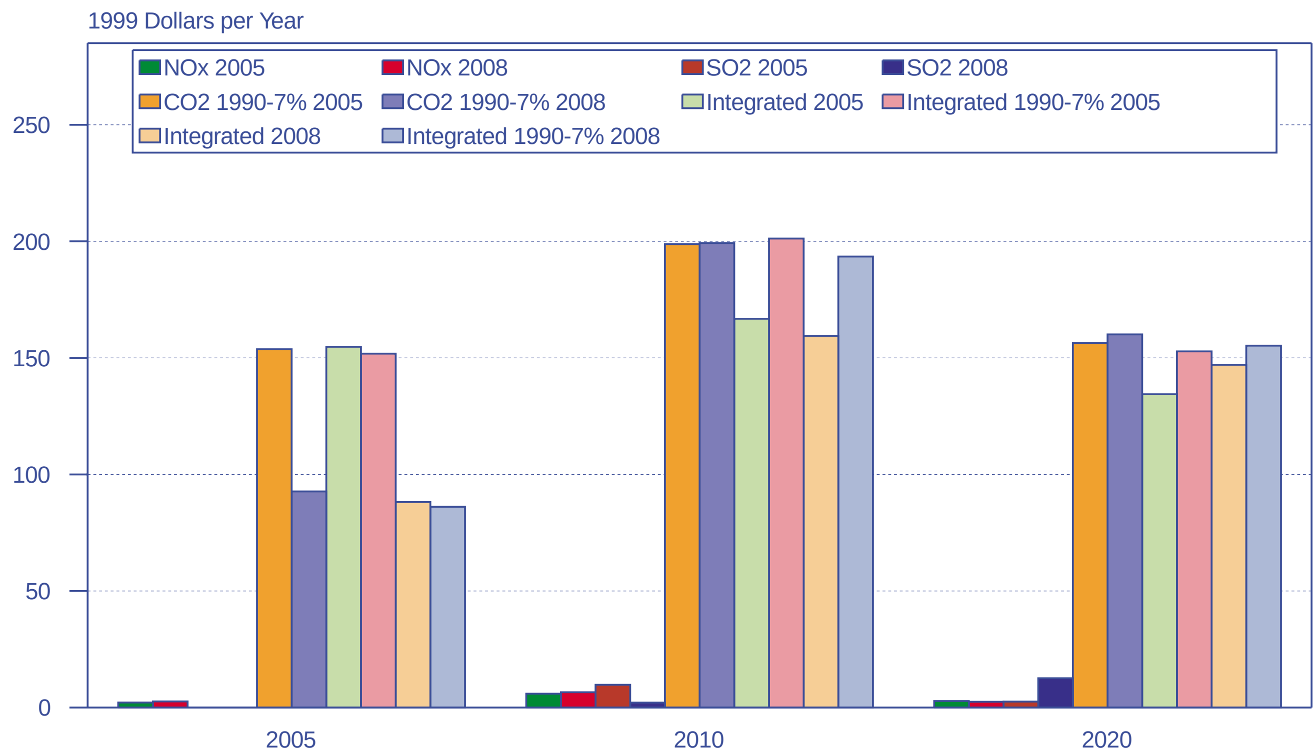
In all the analysis cases, consumers are projected to see higher electricity prices than those projected in the reference case (Figure ES2). In the NO_x cap cases the overall impact on electricity prices is projected to be fairly small,

Figure ES1. Electricity Generation by Fuel, 1949-1998, and Projections for the Integrated 1990-7% 2005 Case, 1999-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05.D121300B.

Figure ES2. Average Projected Changes in Annual Household Electricity Bills Relative to Reference Case Projections, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

approximately 1 percent above the reference case projection in 2010. Similarly, projected average electricity prices in 2010 in the SO_2 cap cases are only 1 percent above the reference case projection. In these cases, the projected costs of compliance are not large relative to the size of the industry, and not all the costs of compliance are expected to be passed on to consumers. As noted previously, however, installing the amount of control equipment projected to be needed in these cases could cause problems if it has to be done over a relatively short time period. The 2005 values shown in Figure ES2 do not incorporate the potential impact on prices of a large amount of capacity being out of service for retrofitting with emission control equipment.

In the cases with CO_2 caps, carbon allowance fees are expected to vary depending on the stringency of the emission cap. Among the cases with CO_2 caps, carbon allowance fees are projected to range between $71 and $120 per metric ton carbon equivalent in 2005, between $108 and $143 in 2010, and between $112 and $141 in 2020. In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 cap is projected to lead to carbon allowance fees that are lower than those projected in the comparable CO_2 1990-7% 2005 and integrated 1990-7% 2005 cases. In 2010, the carbon allowance fees projected in the CO_2 sensitivity case are between $37 and $41 per metric ton carbon equivalent less than those projected in the comparable cases with the more stringent CO_2 caps.

The impact on electricity prices is projected to be much larger in the CO_2 cap and integrated cases than in the NO_x and SO_2 cap cases. Because there are currently no commercially available technologies for removing and storing (sequestering) CO_2 and none is expected to be available during the projection period, the only way to make large reductions in CO_2 emissions is to reduce the consumption of fuels with relatively high carbon content and improve the efficiency of energy production and use. The combination of the projected CO_2 allowance costs, projected increases in operating costs for all fossil-fired generators, and projected increases in wellhead natural gas prices as power companies switch from coal to gas would lead to significantly higher electricity prices. Unlike in the NO_x and SO_2 cases, the operating costs for many of the plants setting the electricity market price are expected to increase, and consumer electricity prices are expected to increase with them.

In the integrated cases, projected electricity prices in 2010 range from 30 to 43 percent higher than in the reference case. Because electricity prices are expected to decline in the reference case, the projected price changes in the integrated cases are not as large when compared with current prices. For example, when compared to the 1999 price, electricity prices in the integrated cases are projected to be between 15 and 26 percent higher in 2010 and between 14 and 20 percent higher in 2020. The low end of the range is projected in the cases that assume a CO_2 emission cap at the 1990 level; the high end is projected in the cases that assume a cap of 7 percent below the 1990 level. For the average household, annual expenditures on electricity are projected to be between $147 and $201 (16 to 22 percent) higher than in the reference case in the integrated cases in 2010 and between $134 and $160 (14 to 16 percent) higher in 2020.

The impact of the assumed CO_2 emission caps on electricity prices is projected to be fairly sensitive to the stringency of the caps. For example, in the CO_2 1990-7% 2005 case, the price of electricity in 2010 is projected to be 42 percent above the reference case level. In the less stringent CO_2 sensitivity case, however, the difference is expected to be only 29 percent. Similarly, average electricity prices in 2010 in the integrated 1990-7% 2005 case are projected to be 43 percent higher than projected in the reference case, but in the integrated sensitivity case they are projected to be only 30 percent above the reference case projection.

Consumers are also projected to see higher natural gas prices because of the power sector's efforts to reduce emissions, especially CO_2 emissions. The increased use of natural gas in the power sector is projected to cause higher natural gas prices in all sectors of the economy, including the residential, commercial, and industrial sectors. In the integrated 1990-7% 2005 case, the Nation's natural gas bill, excluding gas used for electricity generation, is projected to be almost $25 billion higher than in the reference case in 2010. The $25 billion total estimate includes $6 billion for the residential sector, $4 billion for the commercial sector, and $15 billion for the industrial sector.

A coordinated approach to reducing power sector NO_x, SO_2, and CO_2 emissions such as that represented in the integrated cases in this report should lead to lower overall costs than would be incurred with different timetables for each of the emissions. As shown in this report, the compliance decisions that are projected when the NO_x and SO_2 caps are examined alone are different from those projected when the three emission caps are assumed to be combined. The exact savings would depend on the particular scenarios analyzed. The key factor is the timing of the NO_x and SO_2 caps relative to the timing of the CO_2 cap. On one hand, if NO_x and SO_2 caps were imposed and then followed shortly by a CO_2 cap that was unexpected, substantial investments could be made in control equipment that would later prove uneconomical. On the other hand, if the CO_2 cap preceded the NO_x and SO_2 caps, the potential for uneconomical investments in control equipment would appear to be small.

A rough measure of the maximum potential for savings in a coordinated approach would be to compare the cost increase projected in an integrated case with the sum of the cost increases projected in the cases that impose emission caps individually. Table ES5 shows the calculations for the integrated 1990-7% 2005 case and the standalone NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 cases with and without allowance fees. The values without allowance fees (often referred to as "resource costs") represent just the expected increases in expenditures on fuel and other operating costs and the increased investments in new emission control equipment and new capacity. The projected savings in total resource costs are higher in the early years—as much as $6 billion in 2006—because in the integrated cases the expected investments in control equipment to remove NO_x and SO_2 to meet the respective 2005 caps are less than those expected in the NO_x and SO_2 cap cases. After 2015, the projected savings in total resource costs are small. In the integrated case many of the plants to which controls might have been added are expected to be retired.

The projected higher prices for electricity and natural gas in the CO_2 cap and integrated cases would be expected to have an impact on the U.S. economy; however, because the emission caps are assumed to be applied only to electricity producers rather than to all energy producers and consumers, the impact is not expected to be large. In 2005 the projected impact on the U.S. unemployment rate in the integrated 1990-7% case is 0.6 percentage points above the reference case. In the same case, the projected impact on the Nation's gross domestic product (GDP) is projected to be a decline of 1.2 percent from the reference case projection. By 2020 the economic effect is projected to be reduced to a decline of 0.2 percent from the reference case projection.

Fuel Market Impacts

Coal

Because coal-fired power plants are the major power sector emitters of NO_x, SO_2, and CO_2, compliance with the emission caps modeled for this study would be expected to have a major impact on coal consumption and production, both nationally and regionally. The impacts are projected to be relatively small in the NO_x

Table ES5. Projected Changes from Reference Case Estimate of Total Costs of Service for U.S. Electricity Generators, 2005-2015
(Billion 1999 Dollars)

Year	NO_x 2005 Case	SO_2 2005 Case	CO_2 2005 Case	Sum: NO_x 2005, SO_2 2005, and CO_2 2005 Cases	Integrated 1990-7% Case: Projected Costs	Integrated 1990-7% Case: Projected Savings
Including Allowance Costs in Total Costs						
2005	3	3	77	82	77	5
2006	4	3	70	77	68	9
2007	3	4	77	83	74	9
2008	3	3	89	96	87	8
2009	2	4	86	92	88	5
2010	2	4	88	94	86	9
2011	2	4	87	94	84	9
2012	3	5	90	97	87	11
2013	2	3	89	94	89	5
2014	3	3	89	96	87	9
2015	2	3	85	90	86	5
Excluding Allowance Costs from Total Costs						
2005	2	3	21	26	24	2
2006	3	4	20	28	22	6
2007	2	4	22	28	23	5
2008	3	3	27	32	28	4
2009	2	3	26	30	28	2
2010	2	3	28	33	28	5
2011	1	3	28	32	29	3
2012	1	3	29	34	29	5
2013	1	2	30	33	30	3
2014	2	2	31	36	31	4
2015	1	2	29	33	32	1

Note: Totals may not equal sum of components due to independent rounding.
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

cap cases but more significant when SO_2 or CO_2 caps are assumed.

In the two primary SO_2 cap cases, reductions in coal-fired generation and coal consumption (on a Btu basis) are projected through 2020, as other fuels replace coal. Coal mines that supply medium- or high-sulfur coal are projected to have production declines, leading to lower projected minemouth prices for coal from those sources relative to the prices projected in the reference case. To meet the SO_2 emission caps, coal consumption is projected to shift dramatically to favor coal originating from the Powder River Basin in Wyoming and Montana, where surface mines working thick coal seams currently achieve levels of labor productivity that are on the order of 6 to 10 times greater than those in many other regions.

In the CO_2 cap cases, substantial reductions in coal consumption are projected, with corresponding drops in the projections for coal production. To reduce CO_2 emissions, the power sector is expected to move from coal to natural gas and, to a lesser extent, renewables. Because coal has a carbon content more than 70 percent higher per Btu than that of natural gas, the carbon allowance fees in these cases are projected to make the continued operation of many existing coal plants uneconomical.

To continue using coal in the CO_2 cap cases, a power plant operator would have to pay for the coal and for the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2005 case, the delivered price of coal in 2010 is projected to average $0.92 per million Btu, and CO_2 allowances for coal are projected to cost $3.65 per million Btu of energy obtained from coal combustion ($143 per metric ton carbon equivalent). Thus, the effective cost of using coal is projected to be $4.57 per million Btu in 2010 and $4.41 per million Btu in 2020 in the CO_2 1990-7% 2005 case. The corresponding costs in the reference case are projected to be $1.05 and $0.98 per million Btu in 2010 and 2020, respectively. In all the cases with CO_2 caps, continued use of coal is projected to be uneconomical for many plants.

Total coal consumption is projected to be approximately 60 percent below the reference case level in 2020 in the cases with CO_2 caps. As existing coal-fired power plants become uneconomical in the CO_2 cap cases, large blocks of capacity are projected to be retired and replaced by natural gas capacity. The combined effects of lower coal capacity and lower utilization of the remaining coal capacity is projected to reduce coal consumption for electricity generation by 50 to 52 percent in 2010 relative to the reference case projection. Even in the CO_2 sensitivity and integrated sensitivity cases, coal use for electricity generation in 2020 is projected to be 35 percent lower than projected in the reference case.

Natural Gas

For natural gas consumption and production, the projected effects of emission caps are nearly the opposite of those for coal. Imposing emission caps on the power sector is expected to lead to greater use of natural gas, especially when a CO_2 cap is included. For example, in the integrated 1990-7% 2005 case, the electricity generation sector is projected to consume 4.0 trillion cubic feet more gas in 2005 than projected in the reference case, increasing its consumption by 250 percent over the next 5 years. In the case with an assumed compliance date of 2008, the projected increase in natural gas consumption is not as rapid, but it reaches nearly the same level by 2020.

To meet the expected growth in demand for natural gas, both domestic production and imports are projected to increase above the reference case levels. For example, in the integrated 1990-7% 2005 case, domestic production is projected to grow by 4.9 trillion cubic feet between 2000 and 2005, as compared with 2.1 trillion cubic feet in the reference case. Achieving the required levels of natural gas production projected in the CO_2 cap and integrated analysis cases would be a challenge to the industry. Domestic natural gas production grew by 5.7 trillion cubic feet between 1965 and 1970, but there has not been another period of such rapid growth since. It is expected, however, that investors would recognize that limits on CO_2 emissions would lead to higher demand for natural gas—and higher prices—for an extended period, and that the necessary investment in drilling equipment and other infrastructure would be made.

Imports of natural gas from Canada are also expected to play a role in reducing power sector CO_2 emissions. In the integrated 1990-7% 2005 case, imports from Canada are projected to reach 6.1 trillion cubic feet per year in 2020, 0.7 trillion cubic feet more than projected in the reference case. (The projections include growth in Canadian imports as a result of increased gas production in Alaska. New Alaskan gas that is not shipped directly to the lower 48 States is used in Canada, freeing up additional Canadian gas for export to the United States.)

The increased demand for natural gas projected in the cases that include CO_2 emission caps is expected to result in higher prices. For example, in the integrated cases, natural gas wellhead prices are expected to range from $3.75 per thousand cubic fee to $4.33 per thousand cubic feet in 2010, much higher than the $2.68 price projected in the reference case. The highest prices are projected in the cases with 1990-7% CO_2 emission caps beginning in 2005, because of the more rapid increase in consumption projected in those cases and, consequently, the need for rapid increases in production. In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 emission caps assumed are expected to reduce the pressure on gas markets slightly and moderate the projected increase in natural gas wellhead prices relative to the reference case projections. For example, the projections of wellhead gas prices in 2020 are $4.00 per thousand cubic feet in the CO_2 sensitivity case and $4.06 in the integrated sensitivity case.

Renewables

Additional use of renewable energy sources is also expected as a result of efforts to reduce power sector emissions. As the cost of generating power from fossil fuels increases in the emission reduction cases, renewable generation technologies are expected to become relatively more attractive. The projected changes are small in the NO_x and SO_2 cap cases, where the costs of complying with the emission caps are expected to fall mainly on existing fossil plants. In the cases that assume CO_2 caps, however, when carbon allowance fees are added to the operating costs of fossil-fueled power plants, new renewable generating plants and biomass co-firing (mixing biomass with coal in an existing coal plant) are expected to become economically attractive.

The largest increases in renewable electricity generation in the integrated cases with CO_2 caps relative to the reference case are projected for geothermal, biomass, and wind. For example, geothermal electricity generation is projected to increase to 104 billion kilowatthours by 2010 in the CO_2 1990-7% 2005 case, as compared with the projection of 25 billion kilowatthours in 2010 in the reference case. The projection for biomass generation in 2010 (excluding cogeneration) increases from 22 billion kilowatthours in the reference case to 71 billion kilowatthours (17 billion kilowatthours from dedicated plants and 54 billion kilowatthours from co-firing in coal plants) in the CO_2 1990-7% 2005 case. Similarly, generation from wind plants in the CO_2 1990-7% 2005 case is projected to reach 18 billion kilowatthours in 2010 and 86 billion kilowatthours in 2020, as compared with the reference case projections of 12 and 13 billion kilowatthours, respectively. Overall, generation from nonhydroelectric renewables in the CO_2 1990-7% 2005 case is projected to make up 8.0 percent of total electricity generation and 8.5 percent of total electricity sales in 2020.

In the CO_2 sensitivity and integrated sensitivity cases, the amount of renewable capacity added—above the level projected in the reference case—is much less than projected in the cases with more stringent CO_2 caps. In the projections, the relative economics of new renewable capacity are sensitive to the projected carbon allowance fees. In the CO_2 sensitivity and integrated sensitivity cases, only 16 to 18 gigawatts more new renewable capacity is projected to be built than in the reference case by 2020, whereas in the CO_2 1990-7% 2005 case, which assumes the most stringent emission caps in this analysis, 46 gigawatts more new renewable capacity is projected to be built by 2020 than in the reference case.

Potential Impacts of New Source Review Actions

Requiring some or all coal-fired power plants to add equipment to reduce NO_x and SO_2 emissions to continue operating would have a significant impact on NO_x and SO_2 emissions. If the 32 plants currently under suit by the Department of Justice on behalf of the EPA are required to be retrofitted with best available control technology (BACT) to continue operating, as assumed in the NSR 32 case, it is estimated that the SO_2 allowance price in 2010 would be cut by 19 percent relative to the projection in the reference case, from $170 to $137 per ton. Total SO_2 emissions are expected to be 0.6 million tons below the reference case level, because it is assumed that the plants would surrender approximately half their allowances under the terms of an agreement to end the suit. In other words, the national SO_2 emission cap is expected to be lower, and to continue to be binding even after the actions taken by the plants that are being sued.

Similar behavior is expected in the NO_x allowance market. The price impact of requiring the 32 plants to add control equipment is projected to be small. As discussed above, most of the control equipment is expected to be added to plants that do not set the market prices for power, and thus the costs would not be fully passed on to consumers. Where equipment is added to plants in regions with cost-of-service regulation, the projected costs still are not large enough to have a significant impact on electricity prices.

The projected impacts on NO_x and SO_2 emissions and allowance prices are even larger in the NSR All case, which assumes that all coal-fired power plants must be retrofitted with control technology if they are to continue operating after 2010. In this case, both NO_x and SO_2 allowance prices are expected to fall to zero, because when new emission control equipment is added to all operating coal plants, NO_x and SO_2 emissions are projected to be well under established emission caps. For example, in the NSR All case, SO_2 emissions in 2010 are projected to be 1.9 million tons, well under the CAAA90 cap of 8.95 million tons.

A large number of coal plants—31 gigawatts (10 percent of existing capacity)—are expected to be retired in the NSR All case, because adding emission control equipment to them would not be economical. When those plants are retired, however, there would be insufficient baseload capacity (plants intended to run almost continuously) if they were not replaced. The vast majority of the plants retired are projected to be replaced by new coal plants that comply with new source performance standards. As a result, projected CO_2 emissions in the NSR All case are virtually unchanged from those in the reference case. As in the NSR 32 case, electricity prices in the NSR All case are expected to be only slightly above those projected in the reference case. Power plant owners are projected to spend roughly $15 billion on SCR NO_x controls and $58 billion on SO_2 controls, reducing the profitability of the plants but not making them uneconomical.

When the assumptions in the NSR 32 and NSR All cases are combined with those used in the integrated 1990-7% 2005 case described above, the results in the three cases are similar. Comparing the results in the integrated 1990-7% 2005, integrated NSR 32, and integrated NSR All cases shows that, to meet the emissions targets specified by the Subcommittee, the power sector is projected to reduce its use of coal dramatically and to increase its use of natural gas and, to a lesser extent, renewables (Table ES6).

The requirement that emission control equipment must be added to coal-fired plants if they are to continue operating in the integrated NSR All case is projected to lead to more coal plant retirements than projected in the integrated 1990-7% 2005 or integrated NSR 32 case, leading in turn to a lower CO_2 allowance fee in the integrated NSR All case. It is also projected to lead to even greater dependence on natural gas and, as a result, higher natural gas prices. Projected electricity prices are similar to those in the integrated 1990-7% 2005 case.

The NSR cases suggest that efforts to reduce NO_x and SO_2 emissions at existing coal-fired power plants would make a portion of the plants uneconomical, but the majority would continue operating. Additional effort would be needed to reduce power plant CO_2 emissions.

Uncertainty

As with all projections, there is considerable uncertainty in the results of this analysis. Among the key factors that influence the results are the significance of the changes; uncertainty about future fuel prices, particularly for natural gas; potential cost and performance improvements in emission control and generating technologies; the ability of the various energy markets to make the adjustments that would be needed over the next 5 to 8 years; the impacts of the ongoing changes in the structure of electricity markets; and the potential impacts of Hg emission regulations. All these factors could affect the results of this analysis.

Meeting the emission targets specified by the Subcommittee for this analysis would clearly be a challenge for the electricity industry and its associated fuel markets. The timing of the targets—only 5 to 8 years away—may pose the greatest challenge. Planning, siting, obtaining environmental permits for, and building the amount of new gas-fired capacity projected to be needed, as well as developing the natural gas resources that would be required to supply them, could be difficult in the time frame assumed here. Increasing reliance on natural gas in the power sector could place considerable stress on the gas production and delivery infrastructure, leading to price volatility and substantial upward pressure on gas prices. In addition, new technologies for electricity generation, emission controls, and natural gas exploration and development that might be developed over a

Table ES6. Integrated NSR Case Projections, 2000, 2010, and 2020

Analysis Case	Coal-Fired Generation (Billion Kilowatthours)	Gas-Fired Generation (Billion Kilowatthours)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)
2000					
Reference	1,942	599	570	0	6.8
Integrated 1990-7% 2005	1,943	599	570	0	6.7
Integrated NSR 32	1,942	603	570	0	6.7
Integrated NSR All	1,940	607	569	0	6.7
2010					
Reference	2,284	1,123	686	0	5.9
Integrated 1990-7% 2005	1,135	1,839	443	134	8.4
Integrated NSR 32	1,086	1,903	438	132	8.4
Integrated NSR All	1,031	1,988	442	92	8.1
2020					
Reference	2,370	1,866	776	0	6.0
Integrated 1990-7% 2005	852	2,774	440	130	7.8
Integrated NSR 32	869	2,755	439	122	7.7
Integrated NSR All	802	2,856	442	112	7.8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction.
Source: National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, FDP_N32.D121900A, and FDP_ALL.D121900A.

longer period would not be able to contribute significantly to meeting the challenge in the short term.

A key uncertainty with regard to competitive power markets is how consumers and product developers might respond to competitively priced electricity. One feature that has been seen in newly competitive markets is a large amount of price volatility. Because such volatility has not occurred historically, consumers (including homeowners and commercial and industrial establishments) have not invested in equipment that could reduce their exposure to higher prices. It remains to be seen whether the market will become more responsive in the future.