2. Analysis Cases and Methodology

Analysis Cases

The House Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs requested that EIA prepare an analysis to evaluate the impacts of potential caps on power sector emissions of NO_x, SO_2, CO_2, and Hg, combined with a renewable portfolio standard (RPS) requirement. The specific assumptions and cases requested by the Subcommittee are summarized in Table 2. To respond to the Subcommittee's request in a timely manner, the analysis has been divided into two volumes. This report addresses scenarios with NO_x, SO_2, and CO_2 emission caps, as well as scenarios analyzing the potential impacts of ongoing litigation that could require many existing coal plants to add state-of-the-art emissions control equipment. The latter cases, referred to as new source review (NSR) cases, are discussed in Chapter 5.

The reference case for this analysis incorporates the laws and regulations that were in place as of July 1, 2000, as EIA's *Annual Energy Outlook 2001* (*AEO2001*) was being prepared. It includes the CAAA90 SO_2 emission cap and NO_x boiler standards. It also includes the 19-State summer season NO_x emission cap program—referred to as the "State Implementation Plan (SIP) Call." The settlement agreement between the Tampa Electric Company and the Department of Justice (acting for the U.S. Environmental Protection Agency) requiring the addition of emissions control equipment at the Big Bend power plant and the conversion of the F.J. Gannon plant to natural gas is incorporated in the analysis.

Table 2 summarizes the emission targets, timetables, and RPS requirements for each case requested by the Subcommittee. The emission caps (Table 3 and Figure 1) are applied only to the electricity generation sector and are assumed to cover emissions from both utility-owned and independent power plants, excluding cogenerators. If economical, cogenerators are allowed to compete against other power plants to meet the demand for electricity. Because no requirements to reduce emissions in the residential, commercial, industrial, and transportation sectors are assumed, the results of this analysis should not be compared with the results of studies that have examined the impacts of complying with the Kyoto Protocol across all sectors of the economy.

In addition to the cases requested by the Subcommittee, this report includes three cases that assume less stringent emission caps for SO_2 and CO_2 only, and a combined integrated case that uses the less stringent targets (Table 4). These cases were analyzed to examine the sensitivity of the results to the emission targets requested by the Subcommittee for analysis. The emission caps in the SO_2 sensitivity case were set roughly 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 10 percent above 1990 levels, before declining to 7 percent above 1990 levels over the 2008 to 2012 time period.

Using data that recently have become available, the National Energy Modeling System (NEMS) is currently being modified to represent power sector Hg emissions. The expected impacts of the other provisions in each case on Hg emissions are mentioned in Chapter 3, but the proposed Hg emission caps will be analyzed more thoroughly in the subsequent report.

In all cases it is assumed that emission caps would be phased in beginning in 2002. For the cases that require that CO_2 emissions average 7 percent below the 1990 level over the 2008 to 2012 time period, the cap is constructed so that emissions can be slightly above the 1990-7% level in the first year or two of the period and slightly below it in the later years. After 2012, the cap is held at 7 percent below the 1990 level through the remainder of the projections.[4] In addition, it is assumed that the emission reduction programs will be operated as market-based emission cap or fee programs, and the emission allowance prices or emission fees are included in the operating costs of plants that produce one or more of the emissions.

[4]The Kyoto Protocol requires the United States to reduce its greenhouse gas emissions to 7 percent below the 1990 level on average between 2008 and 2012. Requirements for the post-2012 period have not been set. As requested by the Subcommittee, this analysis assumes that the CO_2 cap does not change after 2012.

Representation of New Environmental Rules and Regulations

In Energy Information Administration (EIA) analyses, the reference case incorporates rules and regulations in place at the time of the preparation of the report. Rules or regulations that are not finalized, are in early stages of implementation (without specific guidelines), or are still being developed or debated are not represented. As an independent statistical and analytical agency, EIA does not take positions on how legislative or regulatory issues will be resolved or how rules or regulations will, or should, be implemented.

The reference case for this analysis excludes several potential environmental actions, such as new regulations affecting regional haze, for which States are developing implementation plans; the implementation of new National Ambient Air Quality Standards (NAAQS) for fine particulates, which is still being reviewed by the U.S. Environmental Protection Agency (EPA) and the courts; and the possible ratification of the Kyoto Protocol. In addition, no effort is made to predict the outcome of ongoing studies of the need to reduce power plant mercury emissions[a] or the resolution of lawsuits against the owners of 32 coal-fired power plants accused of violating the Clean Air Act (CAA).

In June 1999, the EPA issued regulations to improve visibility (reduce regional haze) in 156 national parks and wilderness areas across the United States. It is expected that these rules will have an effect on power plants, but the degree to which they will be affected is not known. Power plant emissions of SO_2 and NO_x, which contribute to the formation of regional haze, may have to be reduced to improve visibility in some areas. The regulations call for States to establish goals and design plans for improving the visibility in affected areas; however, State implementation plans (SIPs) are not required until 2004 or later and therefore are not represented in this analysis, because they have not yet been promulgated.

The revised NAAQS, issued by the EPA in 1997, created a standard for fine particles smaller than 2.5 micrometers in diameter ($PM_{2.5}$). As with regional haze, power plant emissions of SO_2 and NO_x are a component of fine particulate emissions. At the request of the President (memorandum July 16, 1997), the EPA is now reviewing scientific data on fine particulate emissions to determine whether to revise or maintain the standard. The review is expected to be completed in 2002. If the standard is maintained, States will be required to submit plans to comply by 2005; however, the NAAQS for fine particulates has been challenged in court, and the resolution of the case is uncertain.

In December 1997, 160 countries met to negotiate binding limitations on greenhouse gas emissions for the developed nations. CO_2 emissions from fossil-fired power plants are a key component of greenhouse gas emissions. The developed nations agreed to limit their greenhouse gas emissions to 5 percent below the levels emitted in 1990, on average, between 2008 and 2012. The target for the United States is 7 percent below the 1990 emission level for all greenhouse gases. Reductions would be required if the U.S. Senate ratified the protocol. At this time, while 29 countries have ratified the protocol, none of the Annex I countries (the developed countries) has ratified the agreement. Various elements of the Protocol are still under negotiation.

The Clean Air Act Amendments of 1990 (CAAA90), Section 112(n)(1)(A), required that the EPA prepare a study of hazardous air emissions from steam generating units. The report was submitted to Congress on February 24, 1998. Its key finding was that Hg emissions from coal-fired power plants posed the greatest potential for harm. The EPA is now collecting and analyzing data on Hg emissions from specific power plants. The data, together with continuing studies on the health effects of mercury, will be used to determine the extent to which emissions need to be reduced. The EPA will be developing proposed regulations for reducing Hg emissions over the next 3 years.

On November 3, 1999, the Justice Department, on behalf of the EPA, filed suit against seven electric utility companies, accusing them of violating CAAA90 by not installing state-of-the-art emissions control equipment on their power plants when major modifications were made. CAAA90 requires that when major modifications are made to older power plants they must also be upgraded to comply with the emissions standards for new power plants. The EPA is arguing that the seven companies and the Tennessee Valley Authority made major modifications to 32 power plants but did not add the required emissions control equipment. At this time, one company, Tampa Electric, has settled the case by agreeing to make modifications to its power plants. The other cases have not been settled.

At the request of the Subcommittee four alternative reference cases with different assumptions about the outcome of the ongoing litigation were examined for this analysis. In the first New Source Review (NSR) case, it is assumed that the owners of each of the 32 plants against which the EPA has taken action will be required to add best available control technology to remove SO_2 and NO_x or retire the plant by 2005. In the

(continued on page 7)

[a]On December 15, 2000, the EPA announced that Hg emissions need to be reduced, and that regulations will be issued by 2004.

Representation of New Environmental Rules and Regulations (Continued)

second NSR alternative reference case it is assumed that all coal-fired plants that do not have flue gas desulfurization (FGD) or selective catalytic reduction (SCR) equipment will be forced to add controls or retire by 2010. The third and fourth NSR cases are the same as the first two, except that they include caps on power sector emissions of NO_x, SO_2, and CO_2. The model evaluates the economics of the retrofit versus retirement decision for each plant. The resolution of these issues could have an impact on future power plant emissions, especially SO_2 and NO_x emissions.

Readers should keep in mind that some of the projected actions and costs incurred to comply with the emissions caps analyzed in this report may also result from the other pending rules and regulations discussed above when they are finalized.

Projections in the reference case in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as now enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

Because there is an existing national SO_2 allowance program, it is assumed that power plant operators will be able to use any SO_2 allowances they have already accumulated. In other words, they can use allowances they have banked. They are not allowed to bank additional allowances after 2000. As a result, the power sector can exceed the SO_2 emission cap beyond the compliance date until their banked allowances are exhausted.

For this analysis, it is assumed that the power sector must explicitly reduce its emissions to meet the CO_2 cap and cannot rely on other mechanisms, such as the flexibility measures included in the Kyoto Protocol that allow countries several options for meeting their emission reduction targets, including direct emissions reductions, land use changes, and forestry changes. For example, a country could get credit for a project to plant trees (reforestation) that absorb CO_2 during their growth. Emissions trading among countries with emission caps is also permitted by the Protocol. The Protocol also covers six greenhouse gases—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—and reductions in any one of them count toward meeting a country's emissions cap. At this time, rules about what type of land use and forestry projects could be implemented and how emissions trading programs might work have not been finalized. If similar provisions were included in a program to reduce power sector CO_2 emissions, the costs of meeting the target most likely would be lower.

After its initial request, the Subcommittee asked that EIA also examine the potential impacts of requiring older coal-fired power plants either to be brought into compliance with current new source performance standards or to be retired. The EPA has taken action against the owners of 32 older coal plants accusing them of making modifications without adding the emissions control equipment required by CAAA90. The first of the four cases—referred to as the New Source Review (NSR) cases—assumes that the owners of each of the 32 plants will be required to add state-of-the-art emissions control equipment by 2005 or retire the plant. The second case assumes that all coal-fired plants that currently do not have such control equipment must make the same decision by 2010. The third and fourth cases combine the assumptions of the first two with more stringent caps on NO_x, SO_2, and CO_2 emissions.

Methodology

AEO2001 Assumptions

The analysis in this report is based on the data and NEMS algorithms used for the *AEO2001*.[5] Because the *AEO2001* forecasts are based on data available at the end of August 2000, the results of this analysis should be evaluated in terms of the relative differences between cases rather than the absolute values.

NEMS Representation

NEMS is a computer-based, energy-economic model of the U.S. energy system for the mid-term period, through 2020.[6] NEMS projects production, imports, conversion, consumption, and prices of energy, subject to assumptions about macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. Domestic energy markets are modeled by explicitly representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most sectors, NEMS

[5]For a summary of the *AEO2001* assumptions, see web site www.eia.doe.gov/oiaf/assumption/.

[6]For a more detailed overview of NEMS, see Energy Information Administration, *The National Energy Modeling System: An Overview 2000* (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/index.html.

Table 2. Analysis Cases

Case Name	Electric Power Sector Emission Caps				Compliance Dates	RPS Requirement
	NO_x	SO_2	CO_2	Hg		
Volume 1 Cases						
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
Volume 2 Cases						
Mercury Case	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	90% below 1997 level	Start 2002; meet target by 2005	None
RPS Case	CAAA90 standards and NO_x SIP Call	CAAA90 cap	None	None	None	5% 2005, 10% 2010, 20% 2020
Integrated Cases with Renewable Portfolio Standard						
Integrated RPS 2005	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet target by 2005	5% 2005, 10% 2010, 20% 2020
Integrated RPS 1990-7% 2005	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; NO_x/SO_2/ Hg targets by 2005; CO_2 1990 level by 2005, 7% below 1990 level in 2008-2012	5% 2005, 10% 2010, 20% 2020
Integrated RPS 2008	75% below 1997 level	75% below 1997 level	1990 level	90% below 1997 level	Start 2002; meet target by 2008	5% 2005, 10% 2010, 20% 2020
Integrated RPS 1990-7% 2008	75% below 1997 level	75% below 1997 level	7% below 1990 level	90% below 1997 level	Start 2002; NO_x/SO_2/ Hg targets by 2008; CO_2 1990 level in 2008, 7% below 1990 level in 2008-2012	5% 2005, 10% 2010, 20% 2020

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.

Table 3. 1990 and 1997 Emissions Levels and Assumed Emission Caps for Electricity Generators

Target	NO_x (Thousand Tons)	SO_2 (Thousand Tons)	CO_2 (Million Metric Tons Carbon Equivalent)	Hg (Tons)
1990 Level	6,663	15,909	475	50
1997 Level	6,191	13,090	533	50
Emission Caps	1,548	3,273	440[a]	5

[a]The integrated 2005 and integrated 2008 cases set CO_2 emissions to the 1990 levels.

Source: 1997 levels from U.S. Environmental Protection Agency, *National Air Pollutant Emission Trends, 1900-1998*, EPA-454/R-00-002 (Washington, DC, March 2000).

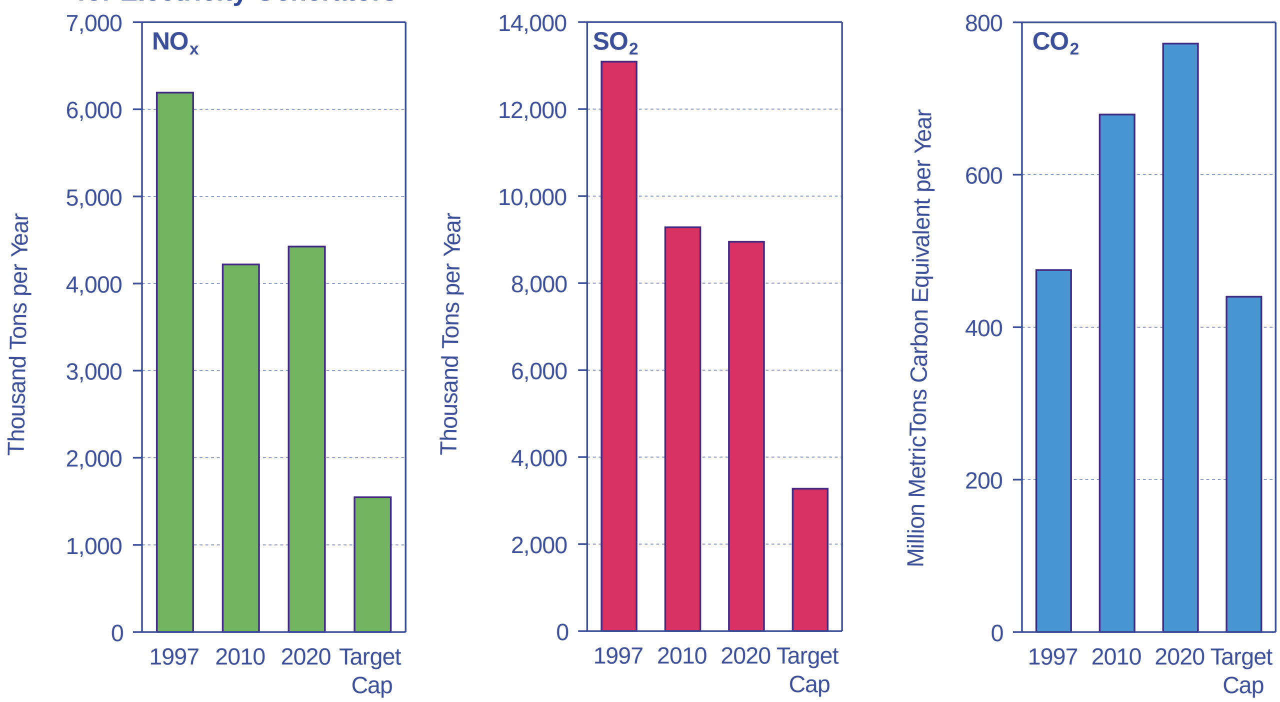
Table 4. Assumed Emission Caps for Electricity Generators in Sensitivity Cases

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.

Figure 1. 1997 Emissions, Reference Case Projections for 2010 and 2020, and Target Caps for Electricity Generators



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run AEO2001.D101600A.

includes explicit representation of energy technologies and their characteristics (Table 5). In each sector of NEMS, economic agents—for example, representative households in the residential demand sector—are assumed to evaluate the cost and performance of various energy-consuming technologies when making their investment and utilization decisions. The costs of making capital and operating changes to comply with laws and regulations governing power plant and other emissions are included in the decisionmaking process.

The rich detail in NEMS makes it useful for evaluating various energy policy options. Policies aimed at a particular sector of the energy market often have spillover effects on other areas that can be important, and the detail of NEMS makes the analysis of such impacts possible. The remainder of this chapter describes how the cases for this analysis were implemented in the key NEMS submodules for electricity, coal, and renewables. Changes in assumptions and modeling approach for this analysis are also explained.

Table 5. National Energy Modeling System Energy Activities

Energy Activity	Categories	Regions
Residential Demand	Fourteen end-use services Three housing types Thirty-four end-use technologies	Nine Census divisions
Commercial Demand	Ten end-use services Eleven building types Ten distributed generation technologies Sixty-four end-use technologies	Nine Census divisions
Industrial Demand	Seven energy-intensive industries Eight non-energy-intensive industries Cogeneration	Four Census regions
Transportation Demand	Six car sizes Six light truck sizes Fifty-nine conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and thirteen alternative-fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Narrow and wide body aircraft Six advanced aircraft technologies Medium and heavy freight trucks Ten advanced freight truck technologies	Nine Census divisions
Electricity	Eleven fossil technologies Seven renewable technologies Conventional and advanced nuclear Marginal and average cost pricing Generation capacity expansion	Thirteen electricity supply regions Nine Census divisions for demand
Renewables	Wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, biomass, conventional hydropower	Thirteen electricity supply regions
Oil Supply	Conventional onshore and shallow offshore Conventional deep offshore Enhanced oil recovery	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural Gas Supply	Conventional onshore and shallow offshore Conventional deep offshore Coalbed methane Gas shales Tight sands Canadian, Mexican, and liquefied natural gas	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions Five liquefied natural gas terminals
Natural Gas Transportation and Distribution	Core vs. noncore Peak vs. offpeak Pipeline capacity expansion	Twelve lower 48 regions Ten pipeline border points
Petroleum Refining	Five crude oil categories Seven product categories Thirty-three technologies Refinery capacity expansion	Three refinery regions aggregated from Petroleum Administration for District Districts
Coal Supply	Three sulfur categories Four thermal categories Underground and surface mining types	Eleven supply regions Thirteen demand regions Sixteen export regions Twenty import regions

Source: Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000).

Representation of NO_x, SO_2, and CO_2 Emission Reduction Programs

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, and that marketable emission allowances or permits will be allocated to power plant operators at no cost (no revenue will be collected by the government). No assumption is made about the specific allocation methodology to be used, other than that it will be a fixed allocation (does not change from year to year) and the total amounts allocated will equal 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.

As allowances are bought and sold, market prices will develop for them and will become part of the operating costs of plants producing the targeted emissions. For example, the total operating costs of a plant that produced one ton of a targeted emission per unit of output would be increased by the price of the allowance. Revenues associated with the sale of allowances go to the seller of the allowances. In all cases it is assumed that the allowance markets will operate as near perfect markets, with low transaction costs and without information asymmetries. In other words, there will be many buyers and sellers of allowances and information needed to evaluate their worth will be readily available. It should be pointed out that there are numerous policy instruments (taxes, emissions standards, tradable permits, etc.) that could be used to reach the proposed emission targets (see box on page 12). The choice of policy instrument will have an impact on the costs of complying with the emission targets and the electricity price and income impacts seen by consumers. The analysis does not employ a generation performance standard as is proposed in several bills (see box on page 14).

Electricity Market Module

The representation of laws and regulations governing power plant emissions is particularly important in the NEMS electricity market module (EMM). The EMM is able to simulate emission caps on SO_2, NO_x, and CO_2. In the reference case for this analysis, the CAAA90 SO_2 emission cap, both Phase I and Phase II, is included. The summer season NO_x emission cap (SIP Call) promulgated by the EPA is also included for 19 States, as discussed above. The EMM simulates the capacity planning and retirement, operating, and pricing decisions that occur in U.S. electricity markets. It operates at a 13-region level based on the North American Electric Reliability Council (NERC) regions and subregions. Based on the cost and performance of various generating technologies, the costs of fuels, and constraints on emissions, the EMM chooses the most economical approach for meeting consumer demand for electricity.

During each year of the analysis period, the EMM evaluates the need for new generating capacity to meet consumer needs reliably or to replace existing power plants that are no longer economical. The cost of building new capacity is weighed against the costs of continuing to operate existing plants and consumers' willingness to pay for reliable service.[7] For nuclear facilities the maintenance versus retirement decisions are made for each plant when it reaches 30, 40, and 50 years of age. At the request of the Subcommittee, the option of constructing new nuclear plants is not considered in this analysis.

The EMM does represent improvements in the cost and performance of new generating technologies as they enter the market. Economic research has shown that successful new technologies tend to show declining costs as they penetrate the market. In the EMM it is assumed that the costs for new technologies decline with each doubling of capacity. As a result, if a policy stimulates the development of a particular technology the EMM will endogenously reduce the cost of that technology as it enters the market in greater quantities. The rate of decline depends on the level of penetration.

During each time period plants are brought on line (dispatched), starting with the unit with the lowest operating costs, until consumers' demand is met. When faced with an SO_2 or NO_x emission cap on electricity producers, the least expensive reduction options available are chosen until the cap is met. The goal of the model is to minimize the costs of producing electricity while complying with emissions constraints. For example, to reduce SO_2 emissions, the options include switching to a lower sulfur fuel, reducing the utilization of relatively high SO_2 emitting plants, adding a flue gas desulfurization (FGD) system to an existing plant to remove SO_2, or retiring a relatively high emitting plant and replacing it with a cleaner plant or, through higher prices, encouraging consumers to reduce their electricity use. This approach allows for SO_2 allowance trading and banking for later use. The marginal cost of reducing emissions sets the allowance price, which is included in the operating costs of plants producing the capped emissions.[8] In NEMS, SO_2 allowance banking decisions can be specified exogenously, or the model can solve for them endogenously. In this analysis, because of stability problems caused by the relationships among the emission caps, banking patterns were specified exogenously for

[7]The capacity planning algorithm determines the appropriate reserve margins in each region by weighing the probability of blackouts (loss of load) and consumers' willingness to pay to avoid them against the cost of building new capacity.

[8]See Appendix K for control costs.

Implementing Emission Caps: Cost and Price Impacts

When emission caps are imposed in the electricity sector, power suppliers can be expected to take actions to reduce those emissions. In some cases they will add emissions control equipment, such as flue gas desulfurization equipment to reduce SO_2 and selective catalytic reduction equipment to reduce NO_x emissions. Depending on the economics, they might also choose to retire some existing generating plants and replace them with plants that have lower emissions. For example, they might retire existing coal-fired plants and replace them with plants that use natural gas or renewable fuels to reduce CO_2 emissions. In turn, in response to price changes, consumers would be expected to reduce their consumption of electricity by increasing their use of non-electric appliances, changing their usage patterns for electric appliances, and investing in more efficient electricity-using equipment.

Each of these actions will have costs. For the power sector, there will be costs associated with increased investments in control equipment and new generating plants. There may also be higher costs associated with maintaining and operating new emission control equipment. Similarly, if new plants require more expensive fuel (i.e., natural gas rather than coal), total fuel costs would also be higher. There also could be costs associated with purchasing and holding emission allowances (or paying fees) on unabated emissions. The degree to which such costs are reflected in consumers' electricity prices (inducing them to reduce their consumption of electricity) and the impact on the economy will be affected by numerous factors.

A variety of policy instruments may be used in efforts to reduce electricity sector emissions. Possible approaches include explicit emissions or technology standards for all generators, a fee on targeted emissions, and marketable (tradable) emission permits assigned or auctioned to generators based on historical emissions (grandfathering) or current year output (such as through the use of a generation performance standard). Each of these policy instruments has cost and price implications.[a]

This analysis assumes a marketable emission permit approach modeled after the SO_2 allowance program created in CAAA90. It is assumed that emission permits or allowances would be provided to affected sources by the regulatory authority, and that the total number of allowances issued to all affected parties would be equal to the national target emissions cap. To be in compliance each year, the number of allowances held for each affected source would have to be equal to or larger than their emissions. Allowances held for an affected source that are not needed could be sold to others.

As allowances are bought and sold a market price will develop for them. Power suppliers will use this price to decide whether to reduce their emissions or purchase allowances to cover them. When deciding whether or not to operate a facility that produces emissions subject to a cap, the owner will include the market price of the allowance as part of the operating costs of the plant. As with fuel, operating the plant will consume an asset—the allowance—that could be sold if the plant were not operated.

The costs associated with the investment and operating decisions made by power suppliers to meet the emissions cap together with the costs of acquiring emission allowances will affect the market price for electricity. In competitive markets the generation price is based on the variable operating costs (what economists refer to as "marginal costs") of the plant setting the market price at any given point in time. In other words, the running plant with the highest operating cost generally sets the market price for power. Typically, for fossil fuel plants, operating costs are dominated by fuel costs, with only a small portion coming from other operating and maintenance costs. If the costs of the plant setting the market price for power are increased by expenditures associated with running new pollution control equipment, using higher cost fuel, and / or purchasing allowances to cover its emissions, the competitive market price for power will reflect those costs. Thus, the total price impact of implementing the emission cap program will include changes in resource costs (i.e., higher operating and maintenance costs and higher fuel costs) together with the allowance purchase costs that raise the operating costs of the plants setting the market price.

While power markets[b] in the United States are becoming increasingly competitive, they are not fully competitive today. In some areas of the country, prices are not set by the marginal costs of producing power. Rather, they are set by dividing the total costs (i.e., fuel costs, operating maintenance costs, capital recovery costs, and a regulated return on investment) by the amount of power sold. In such markets, the costs associated with adding emission control equipment,

(continued on page 13)

[a]For a discussion of the relative merits of alternative policy instruments, see Perman, Ma, and McGilvray, "Pollution Control Policy," in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

[b]This discussion refers only to the generation sector of the electricity market. The transmission and distribution sectors are assumed to continue to price their services on a cost-of-service basis.

Implementing Emission Caps: Cost, and Price Impacts (Continued)

switching fuels, and building replacement plants to reduce emissions would be added to the aforementioned total costs and a new price would be derived. The treatment of allowance costs will depend on how they are allocated and whether the public service commission in a particular State requires costs (or profits) from allowance transactions to be recovered from (or returned to) customers or borne by shareholders. However, because of the increasing role played by wholesale power market transactions and the dominance of independent power producers (IPPs) in building new capacity this analysis assumes that allowance costs will be included in the operating costs of power producers in regulated markets.

It is expected that, even in regulated cost-of-service regions, IPPs will dominate new power plant additions, and because they will have to purchase allowances to cover their emissions, the allowance costs will be included in their competitively priced power contracts with utilities. In the latest data supplied to EIA, utilities reported plans to add 10,623 megawatts of capacity between 1999 and 2003. Over the same time period nonutilities reported plans to add 61,456 megawatts, or 85 percent of the total. As a result, in this analysis it is assumed that IPPs will build all new power plants and sell the electricity at market-based rates—which will include the costs of needed emission allowances.

If the pace of deregulation slows and electricity prices continue to be set on a cost-of-service basis, then assuming that allowance costs would be reflected in the operating costs of all plants with the targeted emissions may overstate the price impacts. The operating costs for existing regulated plants that received allowances at no cost would not include the opportunity costs of holding allowances.

each case. The bank of 11.6 million tons of SO_2 allowances accumulated through 1999 was assumed to be used between 2000 and 2015 in each case.

To reduce NO_x emissions, the options include decreasing the utilization of relatively high emitting plants, adding combustion controls that remove NO_x from the exhaust gases of a plant (i.e., low-NO_x burners) and/or post-combustion controls (i.e., selective noncatalytic reduction [SNCR] or selective catalytic reduction [SCR] equipment), retiring high emitting plants, or, through higher prices, encouraging consumers to reduce their electricity use. For this analysis the emission caps on SO_2 and NO_x specified by the Subcommittee are treated as annual national caps, and allowance trading is allowed among plants throughout the country. It is assumed that the NO_x program would operate like the existing SO_2 allowance program. As with the SO_2 program, the marginal cost of reducing NO_x emissions sets the allowance price.

To reach the power sector CO_2 emissions target, the model chooses among investments in lower emitting technologies (mainly natural gas and renewables), changes in operations of existing and new power plants (using lower emitting resources more intensively than higher emitting resources), and conservation activities by consumers (induced by higher prices). The model solves for the allowance price that encourages power suppliers and consumers to make changes in investment, operations, and conservation activities.[9] In this analysis the CO_2 cap is applied only to the power sector, because emissions in other sectors of the economy are not restricted in the cases specified by the Subcommittee. When multiple emissions caps are imposed, the model solves for the most economical way to meet all of them simultaneously.

The steps taken to reduce NO_x, SO_2, and CO_2 emissions affect the price of electricity. The EMM has the option to price power (the generation component of the energy business) in either a regulated cost-of-service environment or a competitive market environment. Generally, in regions in which the majority of the electricity sales are in States that have passed legislation or enacted regulations to open their retail markets, generation prices are assumed to be derived competitively. The fully competitive regions include California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey, and Maryland), and Texas.

In regions where only a portion of the States have opened their retail markets, the regulated and competitive generation prices are weighted (by the share of sales in the respective states) to derive an average regional price. These regions include the East Central Area, the Rocky Mountain-Arizona regions, the Mid-America Interconnected Network, and the Southwest Power Pool. In all the other regions power prices are assumed to continue to be regulated; however, because wholesale generation markets throughout the country are moving toward competition, all new generators are assumed to be built as merchant power plants that will sell their power at market-based rates. For this reason, this analysis treats the allowance prices that arise when emission

[9]The EMM represents coal- and gas-fired generating technologies with carbon removal and sequestration equipment, but the technologies are not cost-effective in the time frame of this analysis.

Generation Performance Standards

Several of the bills proposing multi-emissions strategies for the electric power sector call for the use of a policy instrument different from the allowance allocations assumed in this analysis—an instrument referred to as a generation performance standard (GPS). The approach used in this report is based on the existing SO_2 program, where emission allowances are allocated to generating plants at the beginning of the program without charge, and the allocations do not change over time. In contrast, under a dynamic GPS approach, allowances would be reallocated each year, based on a plant's megawatthour output. For example, if the national cap on CO_2 emissions were set at 1.914 billion tons (the 1990 CO_2 emission level for the electricity sector) and the total generation for all covered plants[a] equaled 4 billion megawatthours in a particular year, the GPS would equal 0.479 tons CO_2 per megawatthour generated (0.119 metric tons carbon equivalent). Because the generation from covered facilities is expected to change over time, the GPS would be recalculated annually.

A dynamic GPS allowance allocation scheme as described above ("dynamic" because the allocation is revised each year) would lead to different cost and price impacts from those shown in this report. The one-time fixed allowance allocation scheme assumed in this report results in the full allowance price becoming part of the operating costs for all plants producing the targeted emission. For example, if a plant produced 0.200 metric tons of carbon (0.733 tons CO_2) per megawatthour and the carbon allowance price was $100 per metric ton, the operating costs of that plant would increase by $20 per megawatthour ($100 × 0.2). Under the dynamic GPS approach the impact on the same plant's operating costs would be lower. Using the GPS value from the previous paragraph, the plant would need to purchase allowances equal to the difference between its emission rate and the GPS rate—or 0.200 minus 0.119. As a result, the plant's operating costs would only increase by $8 per megawatthour ($100 × [0.200 – 0.119]). If the sample plant were a price-setting plant, the net effect of the dynamic GPS allowance allocation scheme would be that the full cost of holding allowances for the plant ($20 per megawatthour) would not be passed on to consumers. In effect, the plant would receive an output rebate or subsidy of $12 for each megawatthour produced, and the subsidy would be passed on to consumers in the form of lower electricity prices.

Because the full marginal cost of reducing emissions would not be passed on under the GPS scheme, consumers would have a smaller incentive to reduce their electricity consumption than they would with the fixed allowance allocation scheme used in this analysis. Consequently, power suppliers would need to take additional steps to meet the various emission targets, in order to compensate for a smaller demand response from consumers. They would have to reduce coal consumption and increase natural gas and renewable fuel consumption more than they would under a fixed allowance allocation program. The increased use of natural gas can be expected to lead to higher gas prices and, in turn, a higher allowance price to stimulate further reductions.

In comparison with the results presented in this report, the use of a dynamic GPS allowance allocation scheme would be expected to lead to a smaller increase in the price of electricity but higher natural gas prices and a higher CO_2 allowance price. The degree to which natural gas and CO_2 allowance prices would be higher would depend on the expected responsiveness of consumers to higher electricity prices and the sensitivity of the natural gas market to additional demand from the electricity sector.

In this analysis, the natural gas sector is projected to have to increase production by record levels to meet the 2005 CO_2 emission targets, and additional increases in demand from the electricity sector could lead to significant price increases above those already projected. As one expert puts it, "output based rebating sacrifices some of the efficiencies of market-based environmental policies. Allocating by market share essentially provides a subsidy to output, which creates a bias away from output substitution and toward emissions rate reduction. The result is a higher marginal cost of control, a lower equilibrium output price, and a greater cost to achieving any given level of emissions reduction, compared to an efficient policy. The size of the welfare loss from this distortion depends on how much emissions reduction would normally be performed by output substitution."[b]

[a]The definition of "covered units" can differ. In some cases allowances would be allocated to all generating plants; in others they would be allocated only to fossil-fired plants.

[b]C. Fischer, *Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, January 21, 1999).

caps are imposed as if they were imposed on competitive markets. The allowance prices become part of the operating costs of power plants that produce the targeted emissions.[10]

In competitive regions, generation prices are based primarily on the operating costs of the power plant setting the market-clearing price at any given time. In other words, the plant producing power with the highest operating costs sets the price of generation during each time period. An additional adjustment is made to reflect consumers' willingness to pay for reliable service, especially during high usage periods. When emission caps are imposed, the allowance costs or fees associated with them become part of the operating costs for power plants that produce the affected emissions. As a result, in competitively priced regions, the fees or allowance costs for SO_2, NO_x, and CO_2 become part of the operating costs for power plants that burn fossil fuels. When a plant needing emission permits sets the market price for power, the per-kilowatthour cost of holding the permits is reflected in the retail electricity price. This can lead to increased profits for companies owning plants for which emission reduction costs are below the marginal reduction costs. Equally important is the assumption that when the costs fall on plants that do not set the market price, their owners will not be able to pass any of them on to consumers. In regulated regions, the total costs associated with adding emissions control equipment, using higher cost fuels, and retiring or replacing plants to reduce SO_2, NO_x, and CO_2 emissions are recovered along with the costs of holding allowances and other costs.

To represent the RPS (to be analyzed in the forthcoming volume), the EMM has the ability to require that generation from nonhydroelectric renewable facilities (including cogenerators) be greater than or equal to a specified amount. In this analysis the required amount is determined by multiplying the specified share in a given year by the total projected sales of electricity in that year. The most economical nonhydroelectric renewable options are constructed to meet the RPS requirement. As with the emission cap programs described above, the RPS program is operated as a market credit system. It is not required that each power seller produce or purchase the required renewable share. As an alternative, they must hold renewable "credits" equal to the required share. Credits are issued to those generating power from qualifying renewable facilities and, as in the case of SO_2 allowances, may be sold to others. The projected price of the credits becomes part of the operating costs of nonqualifying facilities. In each of the RPS cases it is assumed that the program continues through 2020 and that there is no legislated limit on the credit price.[11]

Coal Market Module

The Coal Market Module (CMM) provides annual forecasts of prices, production, and distribution of coal to the various consumption and energy transformation sectors of NEMS. It simulates production from 11 coal supply regions that meets demands for steam and metallurgical coal from 13 U.S. demand regions and incorporates an international coal trade component that projects world coal trade, including U.S. coal exports and imports.

The CMM uses a linear programming algorithm to determine the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region. Separate supply curves are developed in the CMM for each of 11 supply regions and 12 coal types (unique combinations of thermal grade, sulfur content, and mine type). The modeling approach used to construct the 35 regional coal supply curves represented in the CMM addresses the relationship between the minemouth price of coal and corresponding levels of coal production, labor productivity, and the cost of factor inputs (mining equipment, mine labor, and fuel requirements).

More than 90 percent of U.S. coal production is consumed domestically, and electric utilities and independent power producers account for approximately 90 percent of U.S. consumption. Steam coal is also consumed in the industrial sector to produce process heat, steam, and synthetic gas and to cogenerate electricity. Metallurgical coal is used to make coke for the iron and steel industry. Approximately 6 million tons of steam coal are consumed in the combined residential and commercial sector annually.

Coal is heterogeneous in terms of its energy, sulfur, nitrogen, carbon, and mercury content. Thus, the geographic source of coal can be a significant factor in the physical quantity of coal necessary to provide a given quantity of energy and the resultant level of emissions. Coal prices also vary significantly based on the heat content, quality, and regional source of the coal. For example, low-sulfur, low-Btu coal from the Powder River Basin in Wyoming and Montana has a minemouth price that is only about 20 percent that of some coal types mined in the Appalachian region. The variation in regional coal prices, coupled with shifts in the amount of coal originating from each region, can lead to changes in U.S. average minemouth prices across cases that are

[10] Competitive prices are applicable only to the generation sector of the electricity market. Prices for transmission and distribution services are assumed to continue to be based on cost-of-service regulation.

[11] The Administration's proposed Comprehensive Electricity Competition Act (CECA) limits the credit price to 1.5 cents per kilowatthour.

more related to altered distribution patterns than to the level of aggregate coal demand.

During each year of the forecast period, the CMM receives a set of coal demands, expressed in terms of British thermal units (Btu), required by the different sectors in each region. The demands from the electricity generation sector are further disaggregated into seven categories within each demand region that depend on boiler age, maximum allowable sulfur, and scrubber availability. The EMM also provides the sulfur cap (expressed in tons of SO_2) that represents the maximum emission level for that year. Based on these requirements, and subject to given coal contracts, a linear program within the CMM solves for a supply pattern that meets all demands at minimum cost, subject to the sulfur cap. The allowance price is calculated from this methodology; it is essentially the cost of reducing the last ton of SO_2 under the cap. This allowance price, in turn, is used by the EMM to evaluate the economics of adding FGD equipment to coal-fired generators.

For the most part, the CMM configuration used for the reference case of this study is the same as was used for the *AEO2001*. Certain sections of the linear program layout were restructured to provide a simplified format and improved maintenance and reporting. Other sections of the linear programming code were redesigned to accept case-specific factors to permit a generally smooth drawdown of sulfur allowance banks from current levels (as of 2000) to zero in 2010 for all cases except the sulfur cap cases, which reach zero in 2015. The latter change results in different levels and timing for scrubber retrofits relative to *AEO2001*.

All the analysis cases, with the exception of the NO_x cap cases (which have relatively minor impacts on U.S. coal demand), incorporate two additional changes to the CMM assumptions used for the reference case. All coal contracts (between shippers and utilities) were modified to be phased out no later than 2003. In addition, the set of model constraints that gradually increases the fraction of coal-burning capacity that can be converted to burn low-sulfur, low-Btu subbituminous coal in a given year was changed from the *AEO2001* version to eliminate the constraint by 2003. The two changes were made because accelerated and more stringent emission restrictions are assumed to be likely to constitute sufficient justification to end contracts under *force majeure* provisions. The changes also provide the necessary economic incentive to install, on short notice, modifications to many power plants that will permit the burning of coal blends containing substantial fractions of cheaper subbituminous coal.

Renewable Fuels Module

The Renewable Fuels Module (RFM) consists of five submodules that represent the major nonhydroelectric renewable energy resources—biomass, landfill gas, solar (thermal and photovoltaic), wind, and geothermal energy. The RFM defines technology construction and operating costs, fuel resource volumes and prices (biomass, landfill gas, and geothermal), and resource limitations for each renewable generating technology. These characteristics are provided to the EMM for grid-connected central station electricity capacity planning decisions.

Other renewable energy sources modeled elsewhere in NEMS include conventional hydroelectric (in the EMM), industrial and residential sector biomass, ethanol (in the Petroleum Market Module), geothermal heat pumps, solar hot water heating, and distributed (grid-connected) commercial and residential photovoltaics. In addition to building new biomass plants, the EMM also allows coal-fired power plants to use biomass (wood and waste products) along with coal, a process referred to as “co-firing.” The amount of biomass allowed in co-firing varies from 0 to 5 percent on a heat input basis, depending on the region in which the coal plant is located. The share of biomass allowed is calculated on the basis of its availability in a particular region. Biomass co-firing gives coal-fired power plants the ability to meet environmental regulations by using an alternative low-emission fuel. It is assumed that the coal plants will incur no additional capital or maintenance costs to consume up to 5 percent of their fuel as biomass. In addition, because the trees and plants that become biomass consume CO_2 during their growth, their net emissions are assumed to be zero.

The price-quantity relationship for obtaining biomass fuel is derived from aggregated biomass supply curves that rely on data and modeling done by Oak Ridge National Laboratory to project the quantities of four types of biomass: agricultural residues, energy crops, forestry residues, and urban wood waste / mill residues. Because of recent legislative changes, this analysis (as in *AEO2001*) assumes an extension of the production tax credit under the Energy Policy Act of 1992 from December 31, 1999, through December 31, 2001, granting tax-paying entities that build new wind or closed-loop biomass facilities a tax credit of 1.7 cents per kilowatthour for the first 10 years of electricity generation from qualifying facilities.