1. Background and Methodology

Introduction

Over the next decade, U.S. electric power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in the Clean Air Act Amendments of 1990 (CAAA90). They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. At present neither the future reduction requirement nor the timetable is known for any of these airborne emissions; thus, compliance planning is difficult.

Currently, different environmental issues are being addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, the CAAA90 required operators of electric power plants to reduce emissions of SO_2 and NO_x. Phase II of the SO_2 reduction program—reducing allowable SO_2 emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000.

More stringent NO_x emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, States could require that these emissions be 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 will take effect in 2004. Emissions that lead to fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are emitted directly from electric power plants and are also associated with power plant emissions of NO_x and SO_2. Thus, further reductions in NO_x and SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles.

In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations are to be finalized by 2004. Further, if the United States decides to reduce its emissions of greenhouse gases, energy-related CO_2 emissions may have to be reduced as part of that program.

Analysis Request

In both the previous and current Congresses, legislation has been proposed that would require simultaneous reductions of multiple emissions.[1] This analysis responds to a request from Senators Smith, Voinovich, and Brownback to examine the costs of specific multi-emission reduction strategies (see Appendix A for the requesting letter). In their request, Senators Smith, Voinovich, and Brownback asked the Energy Information Administration (EIA) to analyze the impacts of three scenarios with alternative power sector emission caps on NO_x, SO_2 and Hg. They also asked for an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008.

Specifically, EIA was asked to analyze the following three scenarios for reducing power sector emissions:

- **Scenario 1:** Reduce NO_x emissions by 75 percent below 1997 levels, SO_2 emissions by 75 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 75 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.

- **Scenario 2:** Reduce NO_x emissions by 65 percent below 1997 levels, SO_2 emissions 65 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 65 percent below 1999 levels by 2012, with half the reductions occurring by 2007.

- **Scenario 3:** Reduce NO_x emissions by 50 percent below 1997 levels, SO_2 emissions by 50 percent below full implementation of Title IV of the CAAA90, and Hg emissions by 50 percent below 1999 levels by 2012, with half the reductions occurring by 2007.

[1] For more discussion of proposed bills, see Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

The emission reduction programs are assumed to cover all electricity generators other than industrial cogenerators,[2] and to operate as cap and trade programs patterned after the SO_2 control program created in the CAAA90. It was requested that the analysis should assume that the programs would begin in 2002, achieving half the required reductions by 2007 and full compliance by 2012. At the request of the Senators the existing summer season NO_x cap and trade program is assumed to be replaced by the annual programs established in each of the cases.

For Hg, half of the required reductions were to come from actual reductions at each unit; the rest could be achieved through allowance trading among units. In all cases, power suppliers would be able to bank emissions for future use. In other words, power suppliers could choose to reduce their emissions below the number of allowances they have in some years and hold (bank) them for use in other years. Typically a power supplier would be expected to do this in the early phase of the emission reduction programs, when relatively inexpensive compliance options are available, so that they could minimize the amount of reduction they might have to make or the number of allowances they might have to buy in the later phases, when compliance might be more expensive.

This analysis examines the steps that power suppliers might take to meet the specified caps on NO_x, SO_2, and Hg emissions with and without CO_2 emissions capped at the 2008 reference case level. The potential benefits of reduced emissions—such as might be associated with reduced health care costs—are not addressed, because EIA does not have expertise in this area.[3] The specific design of the cases—timing, emission cap levels, policy instruments used—is important and should be kept in mind when the results are reviewed.

This study is not intended to be an analysis of any of the specific congressional bills that have been proposed in this area, and the impacts estimated here should not be considered as representing the consequences of specific legislative proposals. All the congressional proposals include provisions other than the emission caps studied in this analysis, and several would use different policy instruments to meet the emission targets. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be required as a result of ongoing environmental programs whose requirements currently are not fully specified.

Representation in the National Energy Modeling System

Each of the cases analyzed was prepared using EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economic model of the U.S. energy system for the mid-term forecast horizon, through 2020. 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. Using econometric, heuristic, and linear programming techniques, NEMS consists of 13 submodules that represent the demand (residential, commercial, industrial, and transportation sectors), supply (coal, renewables, domestic oil and natural gas supply, natural gas transmission and distribution, and international oil), and conversion (refinery and electricity sectors) of energy, together with a macroeconomic module that links energy prices to economic activity. An integrating module controls the flow of information among the submodules, from which it receives the supply, price, and quantity demanded for each fuel until convergence is achieved.

Domestic energy markets are modeled by representing the economic decisionmaking involved in the production, conversion, and consumption of energy products. For most sectors, NEMS includes explicit representation of energy technologies and their characteristics (Table 1). In each sector of NEMS, economic agents—for example, representative households in the residential demand sector and producers in the industrial 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 collateral effects on other areas that can be important, and the detail of NEMS makes the analysis of such impacts possible. For example, a policy that leads to higher prices for a particular fuel would be expected to cause residential, commercial, industrial, and transportation customers to

[2]Industrial generators currently account for approximately 8 percent of total generation, with approximately two-thirds being generated from natural gas.

[3]For benefit studies, see bibliography in Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

reduce their consumption of that fuel by shifting to other fuels and/or investing in more efficient energy-using equipment. NEMS explicitly represents these choices by consumers.[4]

NEMS represents numerous options for reducing power sector emissions of NO_x, SO_2, and Hg. Technological options include installing combustion controls, selective noncatalytic reduction equipment (SNCR), or selective catalytic reduction equipment (SCR) to reduce NO_x; flue gas desulfurization equipment to reduce SO_2; and activated carbon injection equipment with or without a supplemental fabric filter or spray cooler to reduce Hg. With respect to Hg and, to a lesser extent, NO_x there is some uncertainty about the cost and performance of these technologies (see box on page 4). NEMS can also choose

Table 1. 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, shared to nine Census divisions
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 Multiple mercury categories	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).

[4]For more information on the representation of emission caps in NEMS, see Chapter 2 in Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

to switch fuels or retire plants and replace them with new plants using different technologies or fuels. Finally, NEMS allows consumers to choose to reduce their electricity consumption if electricity prices rise when emission caps are imposed.

Reference Case

The reference case for this analysis is based on the reference case for EIA's *Annual Energy Outlook 2001* (*AEO2001*). As a result, it incorporates the laws and regulations that were in place as of the end of July 2000. 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."[5] The settlement agreement between the Tampa Electric Company and the U.S. Department of Justice (acting for the EPA) requiring the addition of emissions control equipment at the Big Bend power plant and the conversion of the F.J. Gannon plant

Reducing NO_x and Hg Emissions

Considerable uncertainty exists about the ability of various types of emissions control equipment to remove Hg and, to a lesser extent, NO_x. Many factors affect the level of Hg emissions from a particular power plant, including the Hg content (by speciation—elemental Hg versus various Hg-containing compounds), chlorine content, and other chemical constituents of the coal used; the rank of the coal (i.e., bituminous or subbituminous); the boiler temperature and firing type and the flue gas temperature; and the types of existing control equipment for NO_x, SO_2, and particulates. In recent years data collection and analysis efforts have focused on these factors so that better estimates of current power sector Hg emissions could be developed; however, substantial uncertainty remains. As additional tests are performed, factors currently unaccounted for may turn out to be important.

Data collected by the Environmental Protection Agency in 1999 showed considerable variation in the content of Hg in the coal used by power plants and in the amount of Hg that was removed by the existing equipment at those power plants. On average the sample data show that the Hg content of coal shipped in 1999 was 7.3 pounds per trillion British thermal units (Btu), or approximately 0.2 pounds of Hg per thousand short tons of coal; however, there was considerable variation among coals from different seams, even within a given coal supply region. For example, the 1999 data indicated that coal shipments from the Pittsburgh seam in Northern Appalachia had an average Hg content of 8.2 pounds per trillion Btu, whereas shipments from the Upper Freeport seam averaged 16.4 pounds Hg per trillion Btu.

Even within the same coal seam, the tested shipment data show considerable variation in Hg content. For example, although the average Hg content for the Pittsburgh seam was 8.2 pounds per trillion Btu, the minimum for shipments from that seam was 0.1 pounds per trillion Btu and the maximum was 73.1 pounds per trillion Btu. In statistical terms, the standard deviation for Hg content at the Pittsburgh seam is 4.04, indicating that most samples should have Hg contents between 0.1 and 16.3 pounds of Hg per trillion Btu.

The Hg removal rates for the various coal plant configurations also showed significant variation. The 1999 data show that, on average, a cold-side electrostatic precipitator (CSE)—a particulate removal device—removes 31 percent of the Hg that passes through it. However, the variation among plants with CSEs was large, ranging between 0 percent and 87 percent removal. The situation was similar for facilities with fabric filters—another type of particulate removal device. On average they removed 69 percent of the Hg passing through them, but, after excluding plants that actually reported increases in Hg after passing flue gas through the fabric filter, the removal rate ranged between 54 percent and nearly 100 percent.

In addition, there is very little information on the impact of new NO_x control devices—selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment—on Hg emissions. Although many plant owners plan to add them in the near future, only a few are using them now. With respect to NO_x, SCRs are assumed to reduce emissions by 75 to 80 percent on average; however, because so few plants have SCRs today, the true cost and performance of the technology are not known at this time. With respect to Hg, this study assumes that, when combined with an SO_2 scrubber, an SCR enhances Hg removal with an emissions modification factor of 0.65 (increases Hg removal by 35 percent); however, no additional removal is assumed for plant configurations that have an SCR but do not have an SO_2 scrubber. Some pilot-scale tests suggest that SCRs would increase Hg removal for some system configurations, but the magnitude of the impact is not known at this time.

[5]For more discussion of the treatment of environmental rules and regulations in the reference case, see page 9 of Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard*, SR/OIAF/2001-03 (Washington, DC, July 2001), web site www.eia.doe.gov/oiaf/servicerpt/epp/.

to natural gas was also incorporated in the *AEO2001* reference case. Rules and regulations that have not been fully promulgated are not included in the reference case (see box below).

Because of the recent agreements between the EPA and Cinergy and Virginia Power with respect to the New Source Review (NSR) compliance action, the *AEO2001* reference case has been modified for this study to incorporate the emissions control equipment that those companies have announced they will add. However, these actions could change as a result of the remaining NSR cases. The historical data used for this analysis were also updated to reflect more recent information on natural gas prices, electricity sales, and generating capability additions in 2000 that were not available when the *AEO2001* reference case was prepared. In addition, natural gas prices and electricity demands have been recalibrated to EIA's July 2001 *Short-Term Energy Outlook* (*STEO*). This recalibration resulted in higher gas prices and electricity demand than those used in the *AEO2001*.

Analysis Cases

As requested by the Senators, the emission reduction programs are assumed to be patterned after the SO_2 emissions trading program created in the CAAA90. In other words, emissions allowances totaling to the specified limit for each emission are assumed to be allocated at no cost to power suppliers. Power suppliers are free to reduce their emissions to the level of allowances they hold or to purchase additional allowances from others who take action to reduce their emissions below the number of allowances they have. Power suppliers are assumed to behave competitively, incorporating the

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 Hg emissions[a] or the resolution of lawsuits against the owners of 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.

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. However, the President has indicated that the United States will not support the approach called for in the Protocol. At this time, while 39 countries have ratified the protocol, only one Annex I (developed) country, Romania, has ratified the agreement. In addition, various elements of the Protocol are still under negotiation.

(continued on page 6)

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

costs[6] of holding allowances in the operating costs of plants that produce the targeted emissions. Assuming that efficient competitive allowance markets develop, the market price of allowances that evolves should provide both power producers and consumers with the information needed to minimize the costs of reducing the targeted emissions.

It is important to note that there are numerous policy instruments available for reducing emissions. They include technology standards, percentage reduction requirements, emission taxes, no-cost emission allowance allocation with cap and trade, emission allowance auction with cap and trade, and annual generation performance standard emission allowance allocation with cap and trade. Each of these approaches has different implications for the resource cost, price, and economic impacts of the emission reduction program. In general an efficient cap and trade program is expected to lead to the lowest resource costs of compliance.[7] In competitive markets, electricity prices will reflect the change in variable operating costs of plants setting market prices brought about by emission reduction efforts. On the other hand, in cost-of-service markets, all generation costs—including the total costs of reducing emissions—will be reflected in the prices that consumers pay for electricity.

Table 2 and Figures 1, 2, and 3 show the emission targets in each of the three cases prepared—50-Percent, 65-Percent and 75-Percent Reduction cases. In each case it is assumed that half the required reduction must occur by 2007, and that full compliance is required by 2012. Thus, the emission limits in 2007 are set to the mid-point between the base level and the emission target level shown for each case in Table 2. In 2012 and beyond, the emission caps are set to the levels shown in Table 2.

At the request of the Senators, an additional requirement is imposed for Hg: one-half of the required reductions in each case must come from reductions at each facility, and the other half can be accomplished through trading with other facilities that have allowances to sell. To represent this requirement an estimate was made of the minimum percentage Hg removal (from the amount of Hg in the coal used) required from all units to achieve half the overall required reduction by 2007. For example, in the 65-Percent Reduction case, 28 tons of reduction

Representation of New Environmental Rules and Regulations (Continued)

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 Hg, 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. The continued pursuit and outcome of these cases is uncertain at this time.

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.

[6] Even when allowances are allocated at zero cost, there are opportunity costs associated with them. By using its own allowances, a company forgoes the revenue that could be made by selling them.

[7] For an analysis of the potential impacts of different emission allowance approaches see D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, "The Effect of Allowance Allocation on the Cost of Carbon Emissions Trading" (Washington, DC: Resources for the Future, Discussion Paper 01-30, August 2001); and C. Fischer, "Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards" (Washington, DC: Resources for the Future, Discussion Paper 01-22, July 2001). For a discussion of the impacts of a generation performance standard approach see, J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emissions Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf.

(43 - 15) is required. It was estimated that if all units were required to add equipment that allowed them to achieve a minimum 55 percent removal rate (units that already removed more than 55 percent were not required to make any additional investment), approximately half the 28 tons of total reductions required would be achieved. The same procedures were used in the 50- and 75-Percent Reduction cases, but the minimum removal rates were 50 percent and 60 percent, respectively.

Power sector banking decisions were simulated by setting the emissions caps slightly below those called for in the early years of the programs and slightly higher in the later years. In all cases, it is assumed that emissions will reach the final target caps by 2020.[8]

In addition, for each of the three analysis cases an estimate is provided of the cost of purchasing carbon offsets for increases in CO_2 emissions beyond the 2008 level projected in the reference case. NEMS represents only U.S. energy markets and can only provide cost estimates for reducing emissions in the U.S. energy sector. Lower cost carbon reduction opportunities that might be available in other countries and / or outside the energy sector (inside and outside the United States) are not represented in NEMS.

To estimate the potential price that U.S. power suppliers might be willing to pay for carbon offsets, each of the three analysis cases was rerun with CO_2 emissions capped at the reference case 2008 level. The resulting

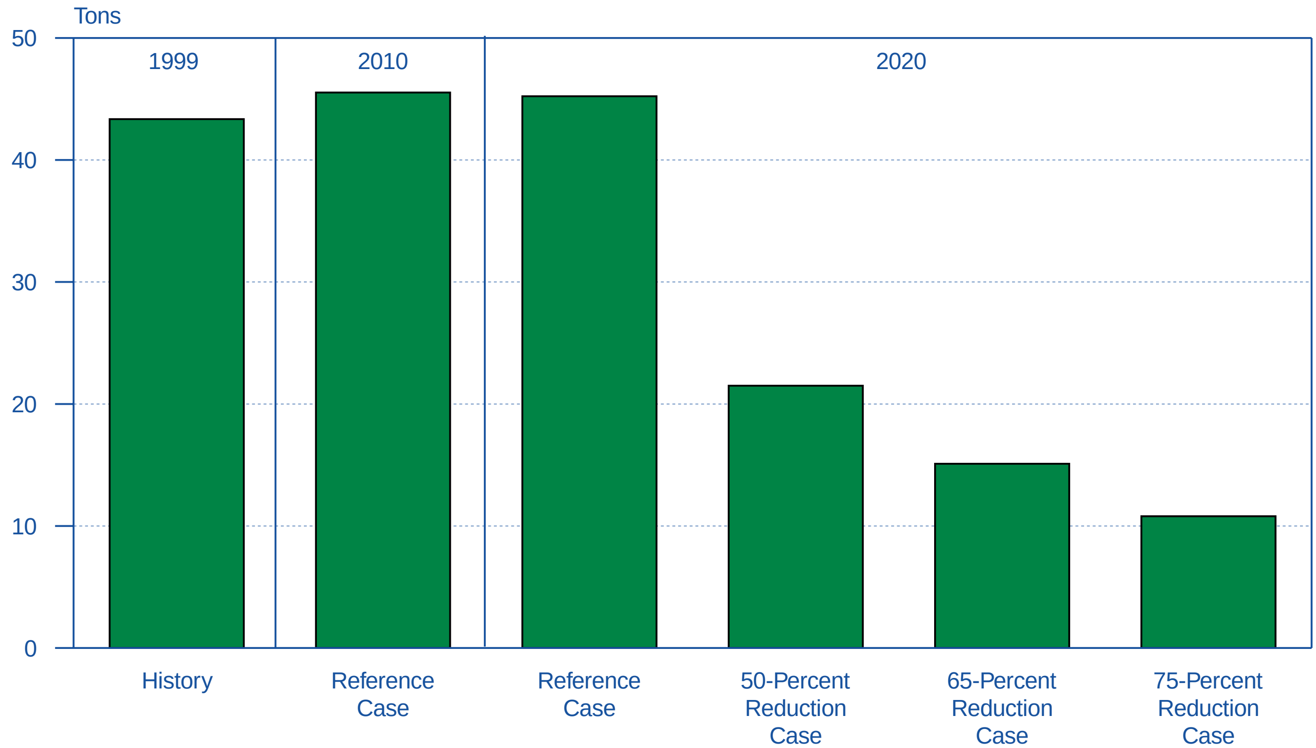
Table 2. Emission Reduction Targets in the Analysis Cases

Emissions	Base Level for Reductions[a]	Reduction Targets: 50-Percent Reduction Case	65-Percent Reduction Case	75-Percent Reduction Case
NO_x (Thousand Tons)	6,191	3,096	2,167	1,548
SO_2 (Thousand Tons)	8,950	4,475	3,133	2,238
Hg (Tons).	43	22	15	11

[a]The base level for NO_x is 1997 emissions. For SO_2 it is the final target in the Clean Air Act Amendments of 1990. For Hg it is estimated 1999 emissions.

Source: Analysis request letter (see Appendix A).

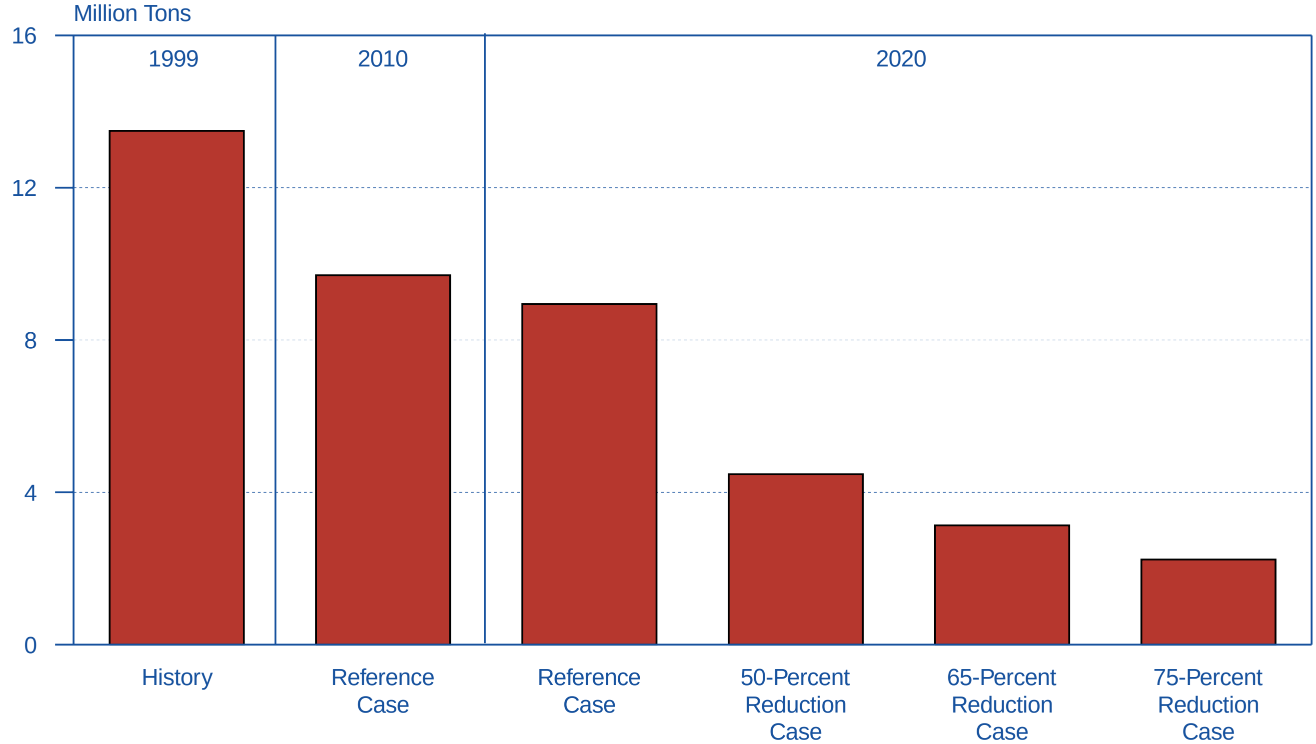
Figure 1. Mercury Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

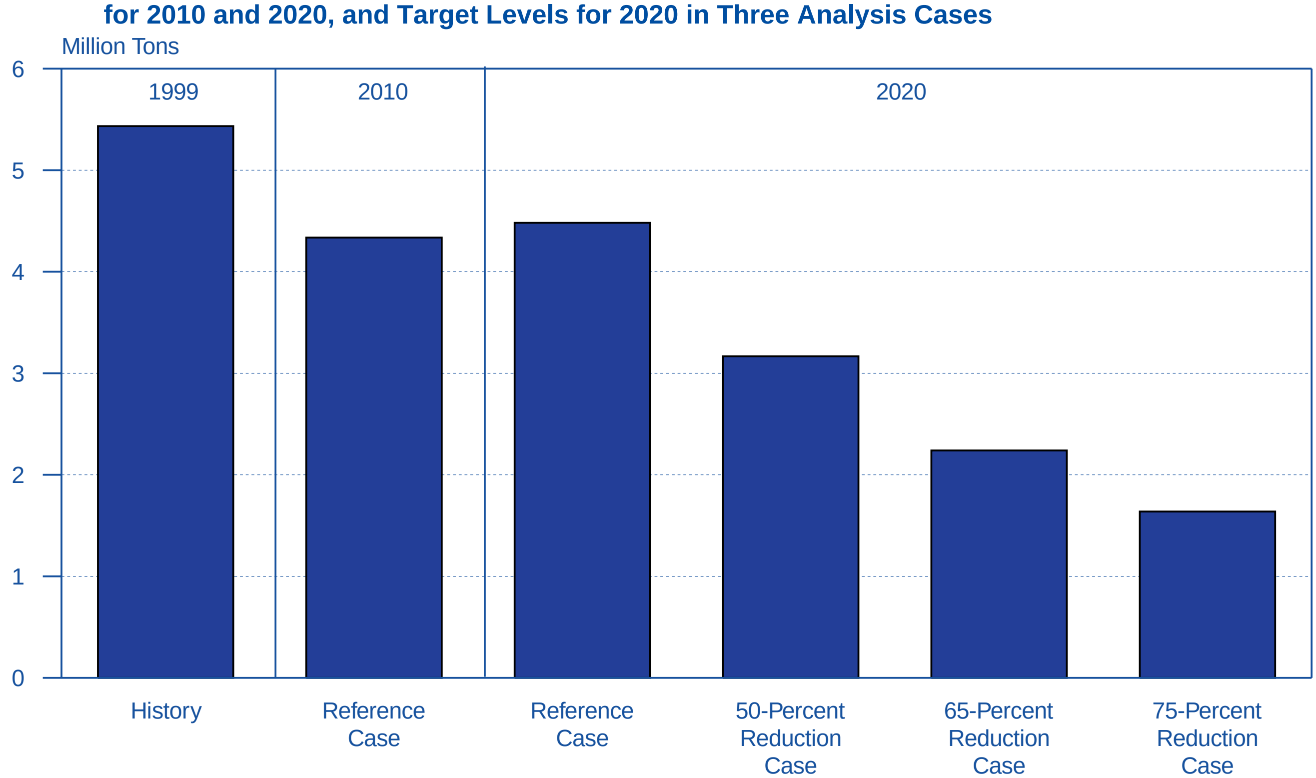
[8]Banking decisions were estimated exogenously.

Figure 2. Sulfur Dioxide Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

Figure 3. Nitrogen Oxides Emissions from Electric Power Plants: 1999 Total, Reference Case Projections for 2010 and 2020, and Target Levels for 2020 in Three Analysis Cases



Sources: **Reference Case:** National Energy Modeling System, run SCENABS.D080301A. **Target Levels:** Analysis request letter (see Appendix A).

CO_2 allowance price, which represents the projected maximum price U.S. power suppliers would be willing to pay, was then compared with an estimate of the international price for carbon offsets from world energy markets. This estimate was developed using carbon reduction (abatement) curves from the Pacific Northwest Laboratory Second Generation Model (SGM), matched against the quantity of offsets projected to be needed in each of the analysis cases,[9] to provide a rough estimate of the costs power suppliers would incur to purchase the offsets they would require in each case. No explicit reductions in U.S. power sector CO_2 emissions were modeled. It is likely that the U.S. power sector would have some relatively inexpensive options available.

[9]Output received from Pacific Northwest Laboratory August 30, 2001. Because the Second Generation Model is an energy sector model, offsets that might be available from non-energy sectors (such as agricultural changes or reforestation activities) are not represented.