Analysis of Multi-Emissions Proposals for the U.S. Electricity Sector
Requested by Senators Smith, Voinovich, and Brownback
Prepared by: U.S. Environmental Protection Agency

This analysis provides the Environmental Protection Agency's response to a June 8, 2001 letter to EPA Administrator Whitman from Senators Smith, Voinovich, and Brownback. The letter requested that EPA analyze the environmental and economic impacts of several different policy options related to multi-emissions control strategies in the nation's electricity sector.

1. Executive Summary

This section briefly outlines the scenarios, methods, and results, first presenting the multi-emissions analysis followed by the greenhouse gas (GHG) analysis.

1.1. Policy Scenarios

The Senators requested that EPA conduct two related analyses. The first analysis focuses on the cost of reducing emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) from the electricity sector, under three scenarios of varying stringency. According to the request, these reductions would be phased in over time. Emissions allowance caps representing half the required reductions would be implemented in 2007 with caps representing the full reductions implemented in 2012. However, banking of emissions allowances would begin in 2002. The analysis assumes a cap-and-trade program for both SO_2 and NO_x in a manner consistent with the existing SO_2 trading program under Title IV of the Clean Air Act. Cap-and-trade for mercury emissions is limited in the analysis, such that half of the mercury reductions are available for trading and half of the reductions in each compliance period represent facility-specific reductions.

The second analysis examines greenhouse gas reductions and the additional costs of offsetting carbon dioxide (CO_2) emissions growth over 2008 levels in the U.S. electricity sector. The Senators requested that the analysis allow the emissions growth to be offset by carbon sequestration or reductions from any greenhouse gas from any source anywhere in the world. In conducting this analysis, EPA considers the possible limits on offset availability as a result of institutional barriers, transaction costs, and/or demand for GHG offsets from other countries.

1.2. Three-Pollutant Analysis

The analysis of the three multi-emission policy scenarios estimates the electricity sector's costs of production, compliance choices, fuel use, plant dispatch, emissions, new capacity, and wholesale electricity prices. To accomplish this, EPA used the IPM® model, an integrated planning model that EPA has also used in rulemakings affecting the electricity sector.

The actual emissions reductions under the three scenarios for 2020 are significantly less than the targeted reductions because of the substantial availability of banked allowances for withdrawal. For example, under Scenario 1 (75% reductions), the actual emissions reductions in 2020 are only 59% for SO_2, 60% for NO_x, and 63% for mercury. Likewise, under Scenario 2 (65% reductions), the actual reductions in 2020 are 52% for SO_2, 51% for NO_x, and 54% for mercury. EPA estimates that the annual cost to the electricity sector of complying with the 3-pollutant scenarios in 2020 varies between 3.1 and 6.9 billion dollars ($1999). The cost of complying with Scenario 3 (50% reductions) is the lowest and Scenario 1 (75% reductions) is the highest. Costs for Scenario 2 (65% reductions) fall between this range at 4.8 billion dollars in 2020.

The predominant compliance strategy for reducing emissions in 2012 and later is a combination of selective catalytic reduction (SCR) and flue gas scrubbers. In addition to investments in emission control technologies, the modeled power plants are expected to modify their operations. Some of the changes in power plant operations result in an increase in natural gas use of 4.4% to 7.3% and a decrease in projected coal use by 3.4% to 6.2%, relative to the Base Case, by 2020. However, coal use for electricity generation remains above 1999 levels under all three scenarios.

The model predicts that a portion of the costs borne by electricity generators in reducing the three pollutants would lead to an increase in wholesale electricity prices of between 1.9% and 2.4%. The effective impact on the retail price is expected to be lower because the wholesale price is only one component of the retail price.

1.3. Greenhouse Gas (GHG) Analysis

EPA analyzed the emissions reductions and additional cost of offsetting U.S. electricity sector CO_2 emissions growth after 2008. EPA's analyses project CO_2 emissions under Scenario 2 of the 3-emission analysis (65 percent reductions) using two alternative baseline forecasts: one using the IPM® and the other by the Energy Information Administration (EIA). The two baselines provide varying results: the IPM analysis requires offsets of six and 58 MMTCE in 2010 and 2020, respectively; while the EIA analysis requires zero offsets in 2010 and 75 MMTCE in 2020. To put these quantities in context, the required offsets represent approximately one percent of U.S. electricity sector CO_2 emissions in 2010, and approximately nine percent by 2020.

The results would likely vary for Scenario 1 and Scenario 3, which have different reduction requirements for SO_2, NO_x, and mercury. Actions taken to reduce emissions of these gases have the additional effect of reducing CO_2 emissions. CO_2 growth slows more under stringent controls for the other gases, meaning that fewer offsets are needed. The multi-emission controls (75% reductions of SO_2, NO_x, and Hg) in Scenario 1 would lead to slightly reduced requirements for offsets, while Scenario 3 (50% reductions in of SO_2, NO_x, and Hg) would likely mean slightly higher CO_2 emissions, and, therefore, a greater requirement for offsets.

To estimate the cost of GHG offsets, EPA used several global-scale economic models including the Second Generation Model (a widely used general equilibrium model) and economic analyses for sinks and non-CO_2 gases. EPA also conducted a number of alternative sensitivity analyses to account for varying program effectiveness and to reflect different levels of international demand for GHG offsets based on possible implementation of the Kyoto Protocol by the countries that reached agreement in Bonn.

In most cases, EPA estimates that abatement costs of a GHG offset program would be negligible through 2020. For these cases, the allowance price associated with the offset program would be equal to the transactions costs of securing the offsets. Estimates of transactions costs, which include private deal-making activities, and government program costs, have not been calculated because of a lack of adequate data. For these cases, only when offset availability is limited to 3% in 2010 or 24% in 2020 do higher allowance prices appear.

EPA also examined cases in which other countries comply with the Kyoto Protocol. With the implementation of the Kyoto Protocol agreement reached in Bonn, there is likely to be no change in U.S. allowance prices or abatement costs through 2010. However, by 2020, U.S. allowance prices could rise to $1-9 (plus transactions costs) per ton of carbon equivalent, and total annual abatement costs in the U.S. could range from negligible to $190 million. EPA has also considered possible cases in which allowance prices could be higher. For example, implementation of the Kyoto Protocol agreement coupled with significant allowance banking in the former Soviet Union and Eastern Europe could raise offset prices to $17 (plus transactions costs) per ton and abatement costs to nearly $500 million by 2020.

Several factors contribute to low abatement costs. First, the Senators requested that the EPA analyze only modest GHG emissions reductions, requiring offsets only in the U.S. electricity sector and only after 2008. Second, the Senators' provision that verifiable GHG reductions or sinks be available anywhere in the global market affords abundant low-cost mitigation opportunities. Limiting the source categories that provide offset credits, either geographically or by type, higher demand for GHG offsets worldwide, or institutional barriers that limit the availability of offsets would raise allowance prices and abatement costs.

The results provided in this analysis should not be construed as forecasts of actual scenario outcomes. The results are assessments of how the future might unfold using a number of well-established economic and emissions analytical modeling tools. The models provide useful insights about the interaction and interrelationships between policy options and resulting environmental and economic outcomes. All models have certain simplifying assumptions, and, though the models produce credible results and have been reviewed by government and private sector experts, they can only be interpreted as representing "reasoned estimates" of the potential outcomes.

1.4. Organization of Document

The remainder of this document presents a detailed explanation of the approach EPA used to obtain these results as well as an elaboration of the results. Section 2 describes the multi-emissions analysis in greater depth. Section 3 provides more information on the approach and results of the GHG offsets analysis. These sections are followed by an Appendix that presents more information on the models and data used in both analyses, as well as a list of references.

2. Multi-Emissions Analysis

This section describes in more detail the multi-emissions scenarios, EPA's analytical methodology, and the results of the Agency's analysis. Note that details about the model used in the analysis can be found in the Appendix.

2.1. Summary of Three Scenarios

The following section describes the important provisions of the multi-emissions scenarios elaborated in the letter from Senators Smith, Voinovich, and Brownback.

- The multi-emissions policies include three scenarios that simultaneously reduce NO_x, SO_2, and mercury emissions from the electricity sector. The three scenarios are similar in program structure, but vary in levels of reduction expected from each of the three pollutants, as shown in Table 1.

Table 1. Emission Scenario Specifications

Emission	Trading	Start Year of Banking	Year for Reduction	Base Emissions	"Scenario 1" 75% reduction from base	"Scenario 2" 65% reduction from base	"Scenario 3" 50% reduction from base
SO_2	Yes	2002	2007	Title IV	37.5%	32.5%	25%
			2012		75%	65%	50%
NO_x	Yes	2002	2007	1997 Level	37.5%	32.5%	25%
			2012		75%	65%	50%
Hg: National	Yes	2002	2007	1999 Level	37.5%	32.5%	25%
			2012		75%	65%	50%
Hg: Plant-Specific	No	No Banking	2007	1999 Level	18.75%	16.25%	12.5%
			2012		37.5%	32.5%	25%

- As described in the letter, each of the three scenarios allows for full trading for NO_x and SO_2, and partial trading for mercury. In addition, banking of emissions allowances begins in 2002, with the first half of reductions required by 2007 (reductions of 37.5%, 32.5%, and 25% respectively for the three scenarios) and full reductions by 2012 (reductions of 75%, 65%, and 50%). For mercury, the scenarios require that half of the reductions made in each of the compliance periods be at the facility level.

- For SO_2, the percentage reductions are from the 1990 Clean Air Act Amendments (CAAA) Title IV levels. For NO_x, the percentage reductions are from the 1997 annual NO_x emissions levels. For mercury, the percentage reductions are from the 1999 levels.

2.2. Methodology

EPA used ICF's Integrated Planning Model (IPM) to model the impacts of the multi-emissions scenarios on electricity sector costs and emissions. IPM® is a dynamic linear programming model that develops least-cost capacity expansion plans while meeting various power market and environmental constraints. This model has been used to support numerous rulemakings that the Agency has undertaken to address emissions from the electricity sector. (See the Appendix for further detail.)

The Agency modeled as closely as possible the provisions indicated in the letter. However, several changes were made to conform to the capabilities and structure of the IPM® modeling framework. Further, certain assumptions related to the definition of the affected units and the spatial scope of this analysis were not specified in the letter and hence were made by the Agency. This section describes the important provisions of the EPA analysis.

- To estimate the impacts of the policies proposed in the three three-pollutant scenarios, EPA ran a Base Case as part of this analysis (i.e., existing requirements without the proposed multi-emissions scenarios). This Base Case incorporated Title IV requirements for SO_2 and NO_x, as well as the summer regional SIP call NO_x program. The Base Case did not include possible future regulations, such as mercury MACT (maximum achievable control technology) standards or state plans to achieve the fine particle ambient air quality standards. The differences (in costs and operations) between each scenario and the Base Case -- which is consistent for all scenarios -- represent the impact of that policy. Thus, the costs of the policies shown in this analysis do not include the costs of these existing programs. Note also that the expected summertime reductions accomplished due to the SIP call program were not available for banking in the three-pollutant scenarios. The possible implications of such an assumption are discussed in Section 2.3.

- The costs presented in this analysis assume that a trading program is available for SO_2, NO_x and mercury within the U.S. electricity sector. EPA expects that the model will accurately anticipate the compliance decisions by sources, provided that an efficient cap-and-trade system is available to those sources subject to the environmental constraints. Based on the experience implementing the existing SO_2 and NO_x cap-and-trade programs, EPA believes that a relatively efficient market can develop for each of these three pollutants.

- The analysis examines the impacts of annual nationwide caps on emissions of NO_x, SO_2, and mercury that are consistent with the specifications described in the letter. The caps on emissions in the analysis are placed on fossil fuel-fired electric generating units for NO_x and SO_2, and all large coal-fired boilers for mercury. Units in the continental United States that are connected to the electric grid are included in this analysis.[1]

- Consistent with the request, EPA modeled all three scenarios with half of the reductions going into effect starting in 2007 and full reductions starting in 2012. In addition, banking is allowed starting in 2002.
- The request based the required NO_x reductions on the 1997 emissions level, the mercury

1 Virtually all of the large units are connected to the grid.

reductions on the 1999 level, and the SO_2 reductions on the CAAA Title IV caps. EPA assumed that the electricity sector emitted 6.04 million tons of NO_x in 1997 and 48 tons of mercury in 1999.[2] The SO_2 emissions under the full implementation of Title IV of the CAAA are assumed to result in 8.95 million tons.

- The request requires that each affected plant achieve at least half of their expected mercury reductions in any given year at the plant site. The amount of actual reductions is based on their actual mercury emissions in 1999. EPA modeled the individual plant-level mercury caps at half of their expected reductions based on the individual plant mercury emissions in the Base Case in 2005.[3]

- EPA ran IPM® for four representative years with at least one snapshot for each distinctly different regulatory period. The years 2005, 2007, 2012, and 2020 represent the pre-cap period when banking is allowed, the partial cap period, the beginning of the fully implemented caps, and the out-year in which the bank is being depleted, respectively.

2.3. Multi-Emissions Results

IPM®-based analysis provides forecasts of the impacts of the three emission reduction scenarios on the electricity sector's emissions, costs of production, compliance choices, fuel use, plant dispatch, new construction, and wholesale energy prices. The primary results from EPA's analysis are summarized below.

2.3.1. Emission Impacts

All three scenarios entail progressive reductions in SO_2, NO_x, and mercury, as well as the banking of allowances starting in 2002. While banking provides flexibility in complying with the specified emission targets and reduces compliance costs, the emission targets may not be met exactly in a given year. This results from sources either reducing emissions beyond what is required (in order to bank allowances) or reducing emissions less than is required (by withdrawing allowances from the bank).[4]

Figures 1 through 4 show the projections of SO_2, NO_x, mercury, and CO_2 in the different scenarios for four representative years. Emissions of SO_2, NO_x, and mercury generally decrease over time for all three scenarios. The more stringent the scenario, the lower the emissions. Note that the CO_2 emissions decrease in the three-pollutant scenarios relative to the Base Case despite the fact that CO_2 is uncontrolled.[5] This occurs because natural gas use increases somewhat with the percentage reduction required.

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2 The base level for NO_x is 1997 emissions from all Title IV affected units. The mercury emission level in 1999 was based on the EPA's recent Information Collection Request on mercury.

3 EPA modeled the plant level mercury reductions at the IPM® model plant level. IPM® model plants are aggregations of individual boilers with similar characteristics.

4 Allowances in a given year are banked for withdrawal in future years if the present value of the price of the allowances in the future years is higher than the current price of allowances. The banking of allowances continues until the current price of allowances equals the present value of the allowances in the future years.

5 The projected decline in CO_2 emissions reflects the operating penalty associated with increased use of scrubbers but not SCR, as described in Table A.1.3. The conservative estimate scrubbers (2.1% capacity penalty) is

Figure 1. NO_x Emissions (million tons)

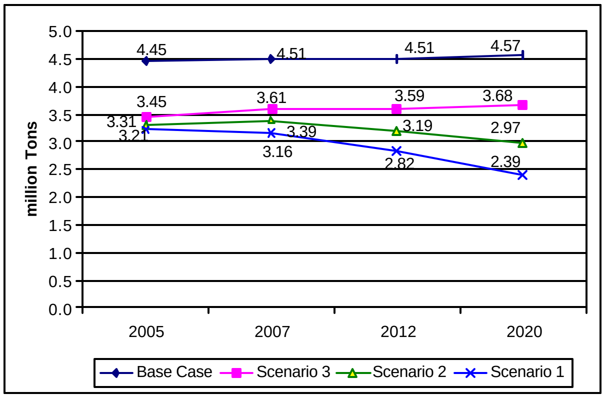


Figure 2. SO_2 Emissions (million tons)

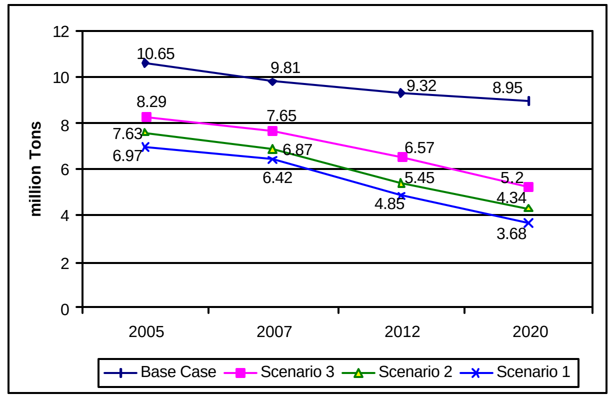


Figure 3. Mercury Emissions (tons)

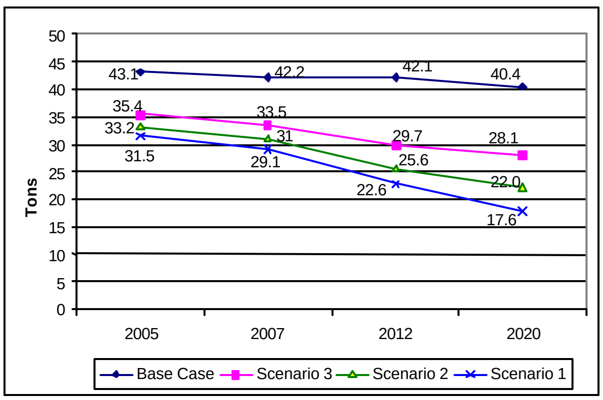
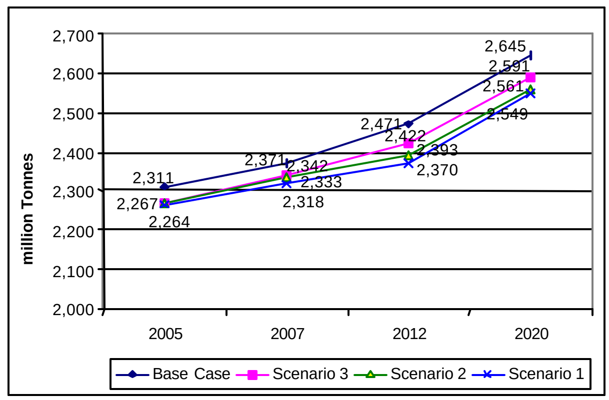


Figure 4. CO_2 Emissions (million metric tons)



The analysis estimates that banked NO_x and mercury allowances would be withdrawn starting in 2012.[6] Banked SO_2 allowances would be withdrawn starting in 2007. Banking occurs when the marginal cost of reducing emissions in a given year is lower than the marginal cost of reducing emissions in a future year, adjusted for the time value of money. The model -- as well as experience -- show that power plants would over-control in the early years and under-control in the later years in order to minimize compliance costs over the period of the analysis.

Figures 5, 6, and 7 show the actual reductions of the three pollutants relative to their respective caps. The actual reductions under the three scenarios are significantly less than the targeted reductions for 2020 because of the substantial use of banked allowances.

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assumed to overcompensate for the minimal penalty arising from SCR.

6 This analysis used the Base Case level of 43.14 tons to calculate banking of mercury allowances during the 2002-2006 period. Alternatively, if the mercury cap was maintained at the 1999 level of 48 tons, increased banking opportunities would have reduced the overall cost of the program. However, this would have increased the effective mercury emissions in later years due to the greater number of allowances that would have been available for withdrawal from the bank.

Figure 5. SO_2 Cap and Projected Emissions under Scenario 1

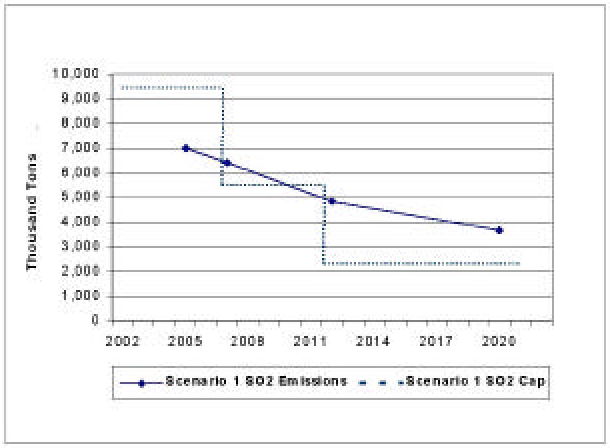


Figure 6. NOx Cap and Projected Emissions under Scenario 1

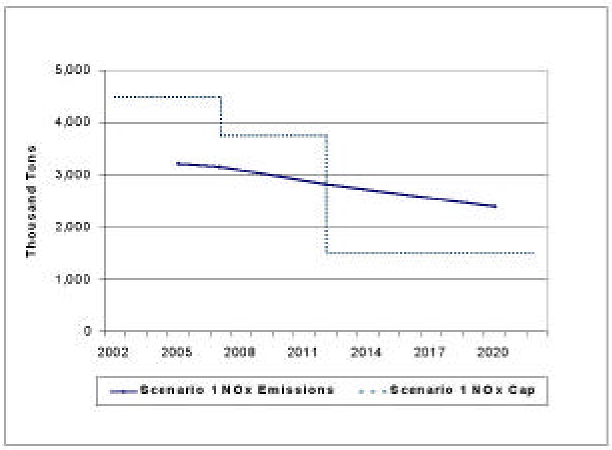
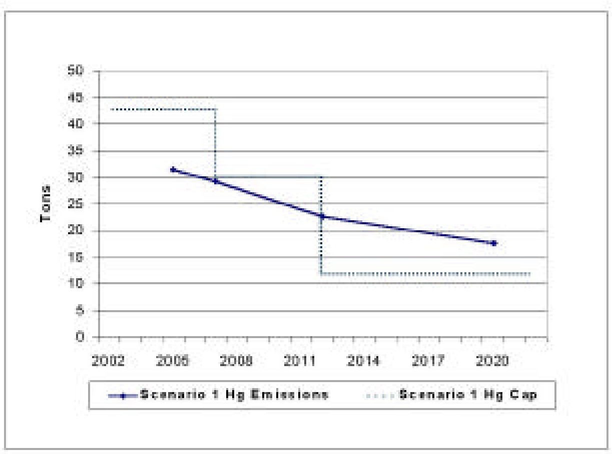


Figure 7. Hg Cap and Projected Emissions under Scenario 1



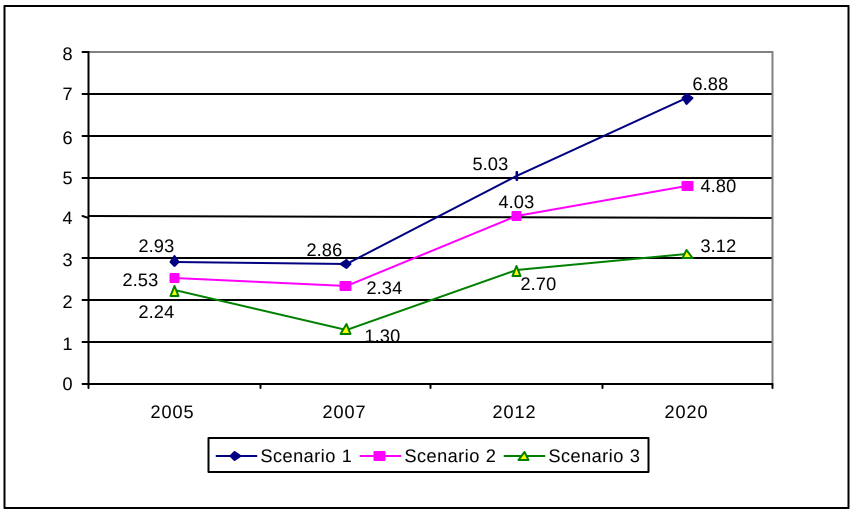
Note: For NOx and mercury, the "cap" between 2002-2006 is included for purposes of calculating the size of the respective allowance banks.

As stated in Section 2.2, this analysis assumed that the SIP call program would be implemented beginning in 2003. If the SIP call were not implemented in the period 2003-2006, the affected power plants in the three-pollutant scenarios would have greater opportunities for banking NO_x emission allowances for the future. Based on a simplified analysis, not implementing the SIP call could increase the NO_x bank up to a maximum of 3.75 million allowances. (For comparative purposes, electricity sector NO_x emissions were 6.04 million tons in 1997.) Such an increase in banked allowances would reduce the overall cost of the policy, but increase the NO_x emissions in the future over what has been shown here. Even without these extra allowances, the NO_x reductions under the three scenarios will probably not achieve emissions levels equivalent to those required by the NO_x SIP call within the 19-state NO_x SIP call region until sometime after 2020.

2.3.2. Cost Impacts

The model calculates operation and maintenance costs, fuel costs, and capital investment costs. The incremental costs for complying with the three-pollutant scenarios over the Base Case are summarized in Figure 8.

Figure 8. Incremental Cost Impacts under the EPA Analysis (Billions of 1999$)



The incremental costs exhibited in Figure 8 reflect the range of decisions made by the electricity sector to comply with the three scenarios. Note that costs are incurred as early as 2005 in all three scenarios, even though explicit emissions reductions beyond Base Case levels are not yet required. These costs are incurred to generate early reductions that can be banked for use in 2007 and beyond when the emission limits for SO_2, NO_x, and mercury come into effect. Costs of compliance increase with time for at least three reasons: (1) the progressive tightening of the caps in 2007 (half reductions required) and 2012 (full reductions required); (2) the increase in demand for electricity over time, resulting in an increase in reduction requirements; and, (3) the gradual reduction in the banked allowances available for withdrawal necessitating additional actions to reduce emissions.

2.3.3. Marginal Costs

The marginal costs of SO_2 and NO_x reductions through 2020 are less than $1,500/ton in all three multi-emissions reduction scenarios. The marginal cost of mercury reductions by 2020 ranges from $5,000 - $10,000/lb. Figures 9, 10 and 11 show the marginal costs for each pollutant.

Figure 9. Projected Marginal Cost of SO_2 Reductions ($/Ton)

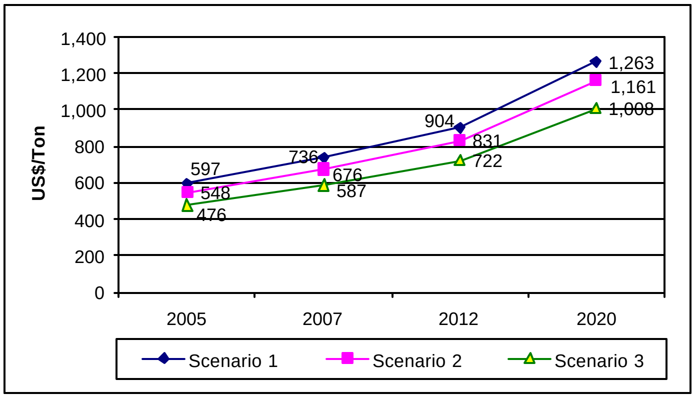


Figure 10. Projected Marginal Cost of NO_x Reductions ($/Ton)

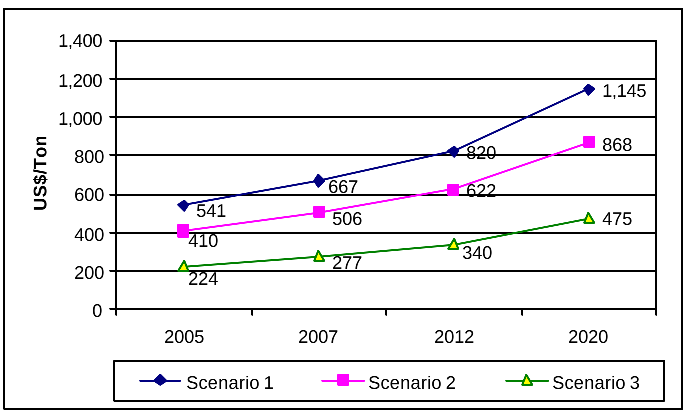
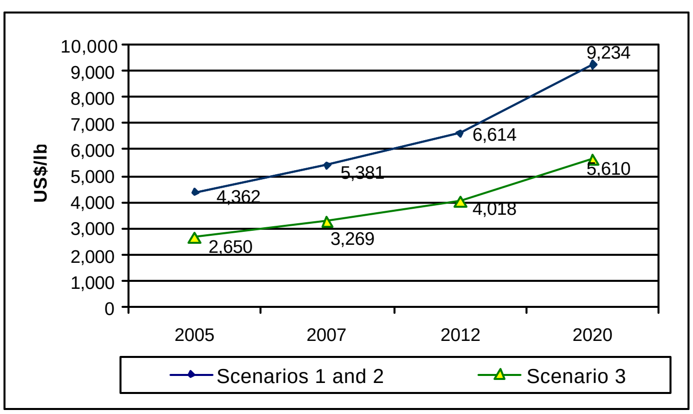


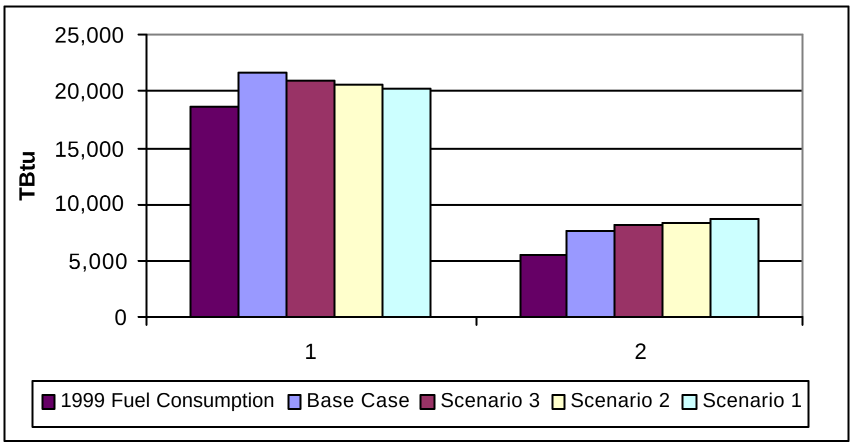
Figure 11. Projected Marginal Cost of Mercury Reductions ($/lb)



2.3.4. Fuel Use Impacts

SO_2 and mercury are fuel-based pollutants, while NO_x emissions are generated largely as a result of the combustion process. Coal-fired power plants emit SO_2, NO_x, and mercury. Gas-fired power plants, in contrast, emit NO_x, but no mercury and virtually no SO_2. Hence, in those scenarios that call for reductions of SO_2, NO_x, and mercury, the replacement of coal-fired generation by gas-fired generation is an effective compliance option. Figure 12 shows the fossil fuel consumption in 2012 in the Base Case and the three three-pollutant scenarios. As the emission reduction requirement increases from left to right, coal use decreases slightly and gas use increases slightly. Under all scenarios, coal consumption is greater than the amount consumed in 1999.

Figure 12. Fossil Fuel Consumption in 2012 (Trillion Btu)



2.3.5. Power Plant Generation

As in competitive wholesale power markets, the model dispatches power plants based on their variable costs, with the lowest variable cost plants dispatched first. In general, coal and nuclear units have the lowest variable costs followed by combined cycle and oil/gas steam units. Combustion turbines have the highest variable costs. Because the variable costs of a power plant include variable operation and maintenance costs, fuel costs, and pollution control costs, these costs increase as emissions limits are imposed or tightened, resulting in changes in plant dispatch.

Figure 13 summarizes the generation from power plants by plant type in 2012 for the Base Case and the three scenarios. In Scenario 3, coal-fired generation in 2012 is 3% lower than in the Base Case, and in Scenario 1 it is 7% lower than in the Base Case. At the same time, in Scenario 3, combined cycle generation in 2012 is 13% higher than in the Base Case, and in Scenario 1 it is 27% higher than in the Base Case. Nuclear generation remains constant throughout the scenarios.

Figure 13. Power Plant Generation in 2012 (Millions of GWh)

Note: 1999 Electric Generation: 3.7 million GWh. Source: EIA

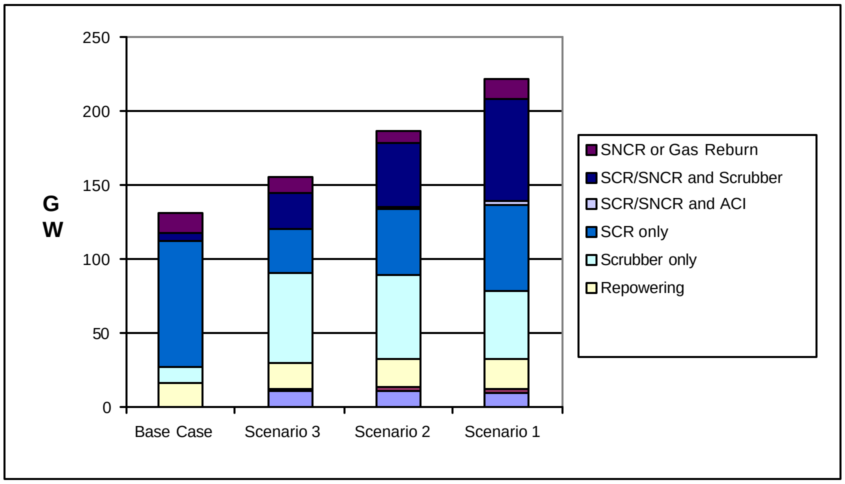
2.3.6. Technology Retrofits

In each scenario, the model forecasts the optimal compliance strategy from an array of options. SO_2 compliance options include dispatch changes, scrubber installation, repowering, and fuel switching. NO_x compliance options include dispatch changes, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and gas reburning equipment. Mercury compliance options include fuel switching, dispatch changes, and installation of activated carbon injection (ACI) controls. The installation of both SO_2 scrubbers and NO_x SCRs has an additional co-benefit of reducing mercury emissions. The replacement of coal generation with combined cycle generation and the early retirement of fossil fuel plants are also available compliance options for achieving the proposed reductions. As with costs, the optimal strategy for the electricity sector varies with the level of targeted emission reductions.

Figure 14 summarizes the optimal retrofit plan forecasted by IPM® for the Base Case and the three scenarios in 2020. The cumulative investments in emission control technology increase with the tightening of the emission reduction requirements. The predominant control technology choices are scrubbers for SO_2 removal; SCR/SNCR for NO_x, and scrubbers + SCR for SO_2, NO_x, *and* mercury removal. Since SO_2, NO_x, and mercury reductions are required for the three-pollutant scenarios, the increase in the combination of scrubbers + SCR/SNCR retrofits is the most significant relative to other retrofit combinations. This increase gets larger as the emission reduction requirements get more stringent. Some of the other technology-based compliance choices forecast by the model include ACI for mercury removal and repowering of coal and oil/gas steam units into combined cycle units. Generally, repowering is one of the more expensive compliance options because the capital cost of repowering an oil/gas steam unit to combined cycle is larger than the capital cost of installing a scrubber + SCR option on an existing coal plant. In addition, the price of gas is more expensive compared to coal. Hence, a significant increase in repowering decisions is not anticipated.

Note that Figure 14 indicates an increase in total SO_2 scrubbers (the summation of power plants investing in new scrubbers alone, in new scrubbers and new SCRs or SNCRs, and in new scrubbers and new ACI as the scenarios get progressively more stringent. Similarly, the total amount of SCRs (summation of power plants investing in new SCRs, and in new SCRs plus scrubbers) increases with increasing emission reductions.

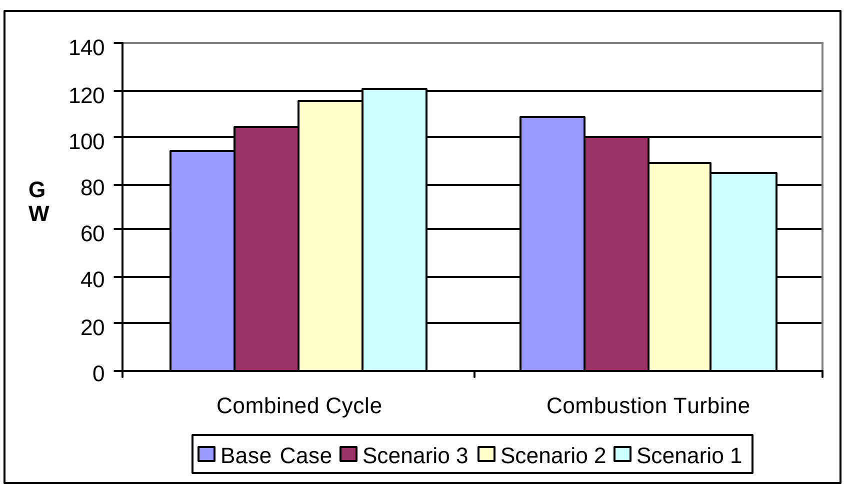
Figure 14. Incremental Retrofit Decisions in 2020



2.3.7. New Unit Impacts

The model forecasts the addition of new capacity to meet increased demand growth and to replace retired capacity. Figure 15 summarizes the cumulative new capacity additions (not including repowered capacity) by 2020. Note that as the emission reduction requirements increase, cumulative new combined cycle capacity increases while new combustion turbine capacity decreases. This occurs because the scenarios favor natural gas, which makes combined cycle plants (with relatively high fixed costs and low variable costs) more economic compared to combustion turbines (which have relatively low fixed costs and high variable costs).

Figure 15. Cumulative New Capacity by 2020 (GW)



2.3.8. Energy Price Impacts

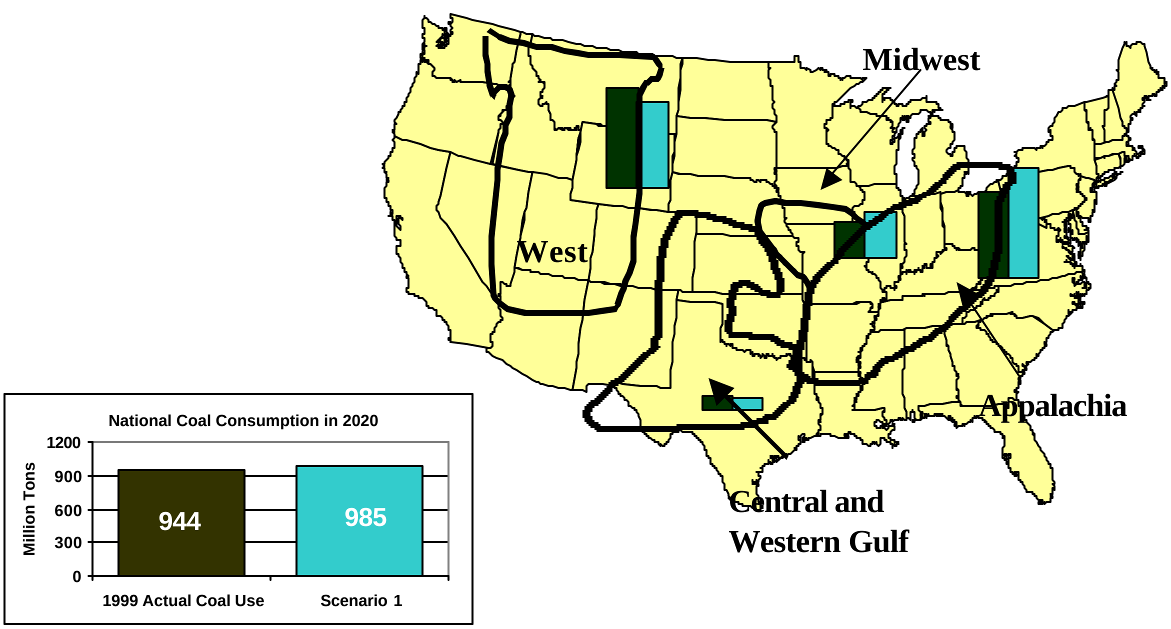
The price of firm power in wholesale markets is based on the variable cost of the marginal unit and the price of capacity.[7] A scenario requiring emissions reductions could influence the variable cost of the marginal unit due to changes in power plants' compliance cost. The impact of the policies on wholesale power price is small, ranging from 0.5 mills/kWh to 0.7 mills/kWh, or 1.9% to 2.4%, respectively. The percentage impact on consumers would be less, reflecting the other components of consumer price not affected by these scenarios.[8]

2.3.9. Regional Impacts

The impacts of the three scenarios on emissions and coal consumption vary in the different regions of the contiguous United States. Figure 16 shows the projected impact of Scenario 1 on power generator's coal consumption by coal production region. Likewise, Figures 17, 18 and 19 show the projected impact of Scenario 1 on regional SO_2, NO_x, and mercury emissions, respectively. The regional impacts of Scenarios 2 and 3 would be similar -- but less significant -- than those for Scenario 1.

Figure 16. Coal Consumption by Coal Production Region in 1999 and 2020
(Source of 1999 Actual Coal use is EIA Annual Energy Review (DOE/EIA-0384(99)), Table 7.3, Coal Consumption by Sector.)

Scale: Appalachia Coal, 'Scenario 1"= 361 million tons



7 The firm power price is estimated under the assumption that the power plant is selling capacity in all hours.
8 This analysis assumed a permanent allocation of emission allowances.

Figure 17. Regional SO_2 Emissions from Power Generators in 2020
(Note: graphic includes emissions from all units that are connected to the grid.)

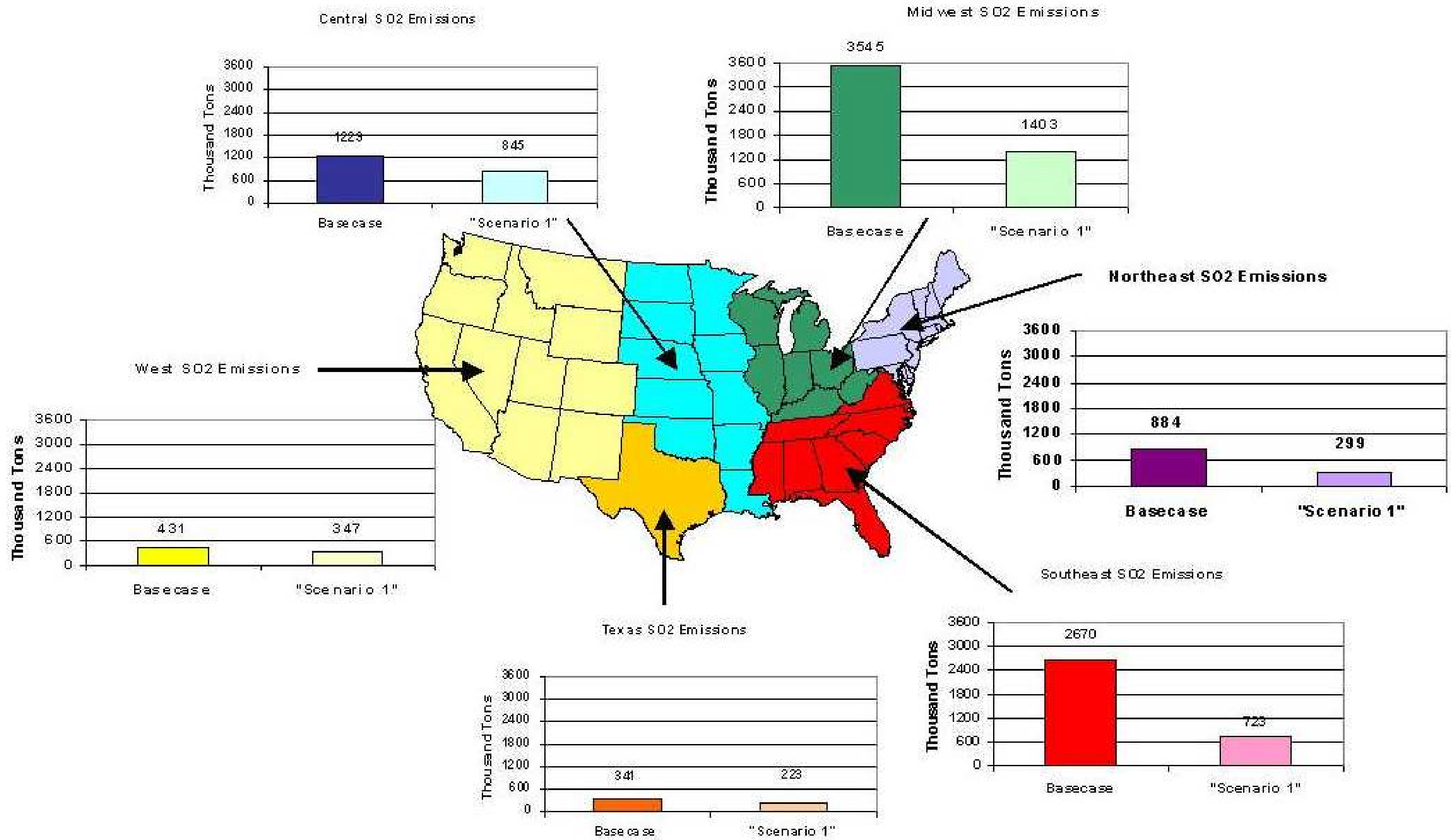


Figure 18. Regional NO_x Emissions from Power Generators in 2020
(Note: graphic includes emissions from all units that are connected to the grid.)

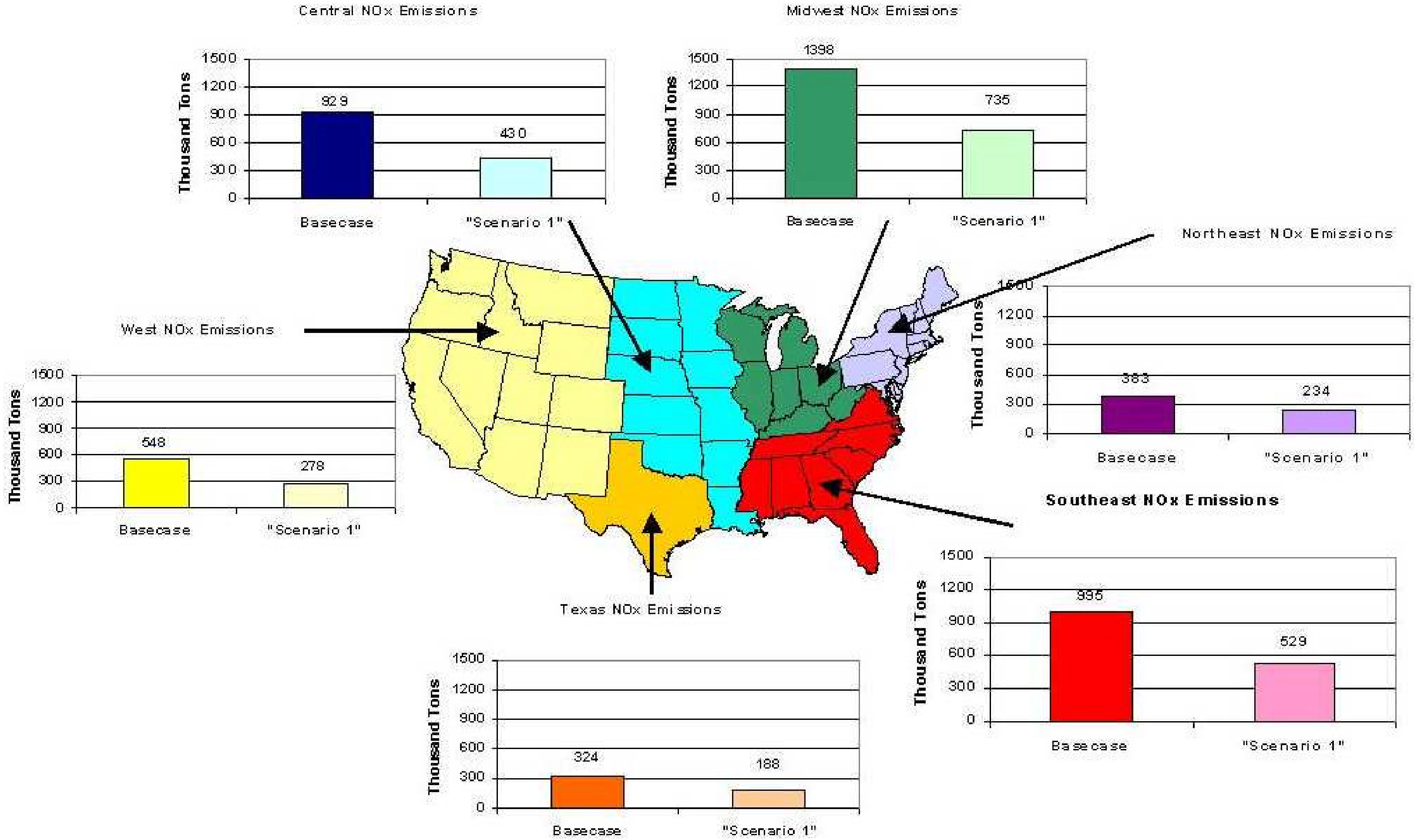
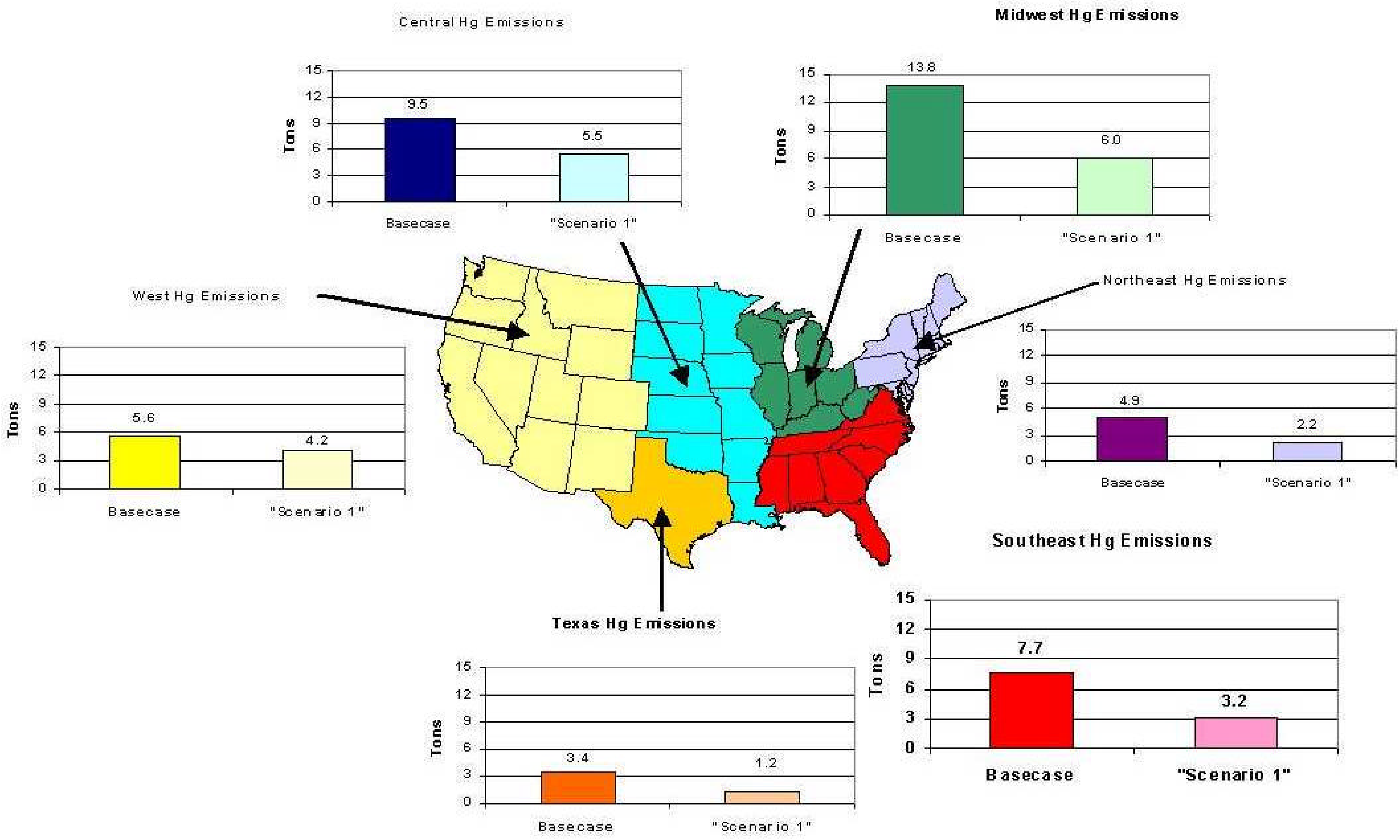


Figure 19. Regional Mercury Emissions from Power Generators in 2020
(Note: graphic includes emissions from all units that are connected to the grid.)



3. Greenhouse Gas Analysis

In addition to investigating policies to reduce SO_2, NO_x, and mercury emissions, the Senators asked EPA to analyze the impacts of requiring that U.S. electricity sector carbon dioxide (CO_2) emissions increases above 2008 levels be offset. The request specifically allows for offsets "...by reductions or sinks in any sector of any greenhouse gas in an amount equal to the warming potential of the emissions to be offset. Assume that verifiable reductions or sinks achieved in any nation could be available on the domestic emissions market to satisfy this requirement."

This analysis uses two different projections of CO_2 emissions in the U.S. electricity sector through 2020, coupled with three variations of offset program effectiveness and alternative assumptions about international offset demand. EPA's analysis shows that needed offsets range from zero to six million metric tons carbon equivalent (MMTCE) in 2010 to between 58 and 75 MMTCE in 2020.[9]

In most cases, EPA estimates that abatement costs of a GHG offset program would be negligible through 2020. For these cases, the allowance price associated with the offset program would be equal to the transactions costs of securing the offsets. Estimates of transactions costs, which include private deal-making activities, and government program costs, have not been calculated because of a lack of adequate data. For these cases, only when offset availability is limited to 3% in 2010 or 24% in 2020 do higher allowance prices appear.

EPA also examined cases in which other countries comply with the Kyoto Protocol. With the implementation of the Kyoto Protocol reached in Bonn, there is likely to be no change in U.S. allowance prices or abatement costs through 2010. However, by 2020, U.S. allowance prices could rise to $1-9 (plus transactions costs) per ton of carbon equivalent, and total annual abatement cost in the U.S. could range from negligible to $190 million. EPA has also considered possible cases in which allowance prices could be higher. For example, implementation of the Kyoto Protocol agreement coupled with significant allowance banking in the former Soviet Union and Eastern Europe could raise offset prices to $17 (plus transactions costs) per ton and abatement costs to nearly $500 million by 2020.

Unless one of these higher priced scenarios is realized, however, the fuel mix in the electricity sector is not likely to be affected because reductions are likely to occur outside the sector, given the low costs of offsets under the scenario requested.

3.1. Emissions Forecast and Required Emissions Offsets

To examine the scenario in which the U.S. electricity sector offsets CO_2 emissions above 2008 levels as part of a multi-emissions approach, EPA applied two base cases for electricity sector CO_2 emissions through 2020. One is generated from IPM® and the other is from EIA. Both

9 The models used for this analysis yield output in five- or ten-year increments. Therefore, EPA provides results for 2010 and 2020. The results provided in 2010 and 2020 are the emissions to be offset in those years alone.

projections incorporate the CO_2 reductions from the application of the multi-emissions control program.

3.1.1. IPM® Multi-Emissions Base Case

EPA used IPM® to forecast electricity sector emissions in 2008 and emissions growth through 2020. The IPM® projection is based on EIA data, but is adjusted to account for emissions reductions resulting from the government's energy-efficiency programs, such as Energy Star®. It assumes that the sector is also reducing SO_2, NO_x, and mercury emissions under Scenario 2 of the Senators' request. The SO_2, NO_x, and Hg emissions control measures result in the ancillary benefit of CO_2 emissions reductions within the electricity sector. Consequently, CO_2 emissions under Scenario 2 are lower than those of the IPM® Base Case. The IPM® three-emissions forecast for CO_2 emissions in 2008 is approximately 640 million metric tons of carbon equivalent (MMTCE) (about 2,350 million metric tons of CO_2 equivalent). The projected emission offset requirement is six MMTCE in 2010 and 58 MMTCE in 2020.

3.1.2. EIA Base Case

EPA used CO_2 emissions projections from EIA's analysis entitled "Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides and Mercury Emissions from Electric Power Plants"[10] to develop the EIA Base Case. To be consistent with the IPM® Base Case, EPA took the EIA multi-emissions case that would reduce SO_2, NO_x and mercury by 65%. The projected offset requirements under the EIA Base Case are zero MMTCE in 2010 and 75 MMTCE in 2020.

3.2. Methodology

This section provides background on emissions offset programs and describes the approach and assumptions that EPA used in conducting the analysis.

3.2.1. Background

GHG "offsets" generally refer to emissions reductions or sequestration of GHG emissions achieved outside of the source categories that have an emissions cap. In the case of an electricity sector offset program, electricity generators would be able to use offsets created through emission reductions or sequestration of GHG emissions by sources outside the cap on CO_2. (See the Appendix for a description of offset source categories analyzed in this analysis.)

Allowing for offsets of CO_2 emissions from any GHG source in any sectors of the economy, domestically and internationally, would reduce the cost of achieving emissions reduction targets. A commonly used index known as the "Global Warming Potential" (GWP) allows for the comparison of greenhouses gases in terms of their relative contribution to climate change.[11] For

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10 U.S. Energy Information Administration: "Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides and Mercury Emissions from Electric Power Plants", September 26, 2001 prepared for Senators Smith, Voinovich and Brownback.

11 The GWP range for non-CO_2 gases (15 different gases) varies between 21 for methane and 23,900 for sulfur hexafluoride (SF_6). For example, the 100-year GWP of methane is 21, indicating that one ton of methane released

this report, the 100-year GWP of each greenhouse gas is used to express quantities in millions of metric tons of carbon equivalent (MMTCE).

Fossil fuel electricity generation is the largest source of domestic anthropogenic CO_2 emissions, accounting for approximately 40 percent of total U.S. CO_2 emissions in 1999.[12] Numerous options exist for reducing CO_2 emissions within the electricity sector, including generation efficiency improvements, transmission and distribution system efficiency improvements, and fuel switching to less carbon intensive fuels. For example, the electricity sector can and currently does use non-GHG-emitting energy sources, such as wind, solar, hydropower, and nuclear power.

Though there are many opportunities for CO_2 reductions in the electricity sector, there are potential advantages to an offset program involving other sectors. First, allowing the electricity sector to purchase reductions from other sources will reduce the cost of achieving the cap. A number of U.S. and international analyses have shown that some of the most cost-effective mitigation options are likely to be terrestrial carbon sequestration and reductions of non-CO_2 gases including methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).[13] The costs of many carbon sequestration activities or mitigation projects that reduce non-CO_2 GHGs can be totally or partially recovered through increased efficiency, recycling of materials, or the capture and sale of the gas (e.g., methane).

Thus, this analysis incorporates a set of GHG mitigation options called “no-regrets,” where the cost of the project is completely recovered. “No-regrets” mitigation options allow the electricity sector to purchase offsets from these other sources, thus reducing the cost of, and potentially providing a net benefit for, achieving the reduction goal. Second, reduction of GHGs from sources outside the capped electricity sources may provide ancillary environmental benefits (e.g., reduced air pollution) that otherwise would not have been realized. Third, financial incentives resulting from an offset program might accelerate the development and use of new emissions reduction technologies.

3.2.2. Analytic Approach

A number of important factors affect the potential costs and availability of GHG offsets in a domestic and world market. Three factors are described here—the strength of economic incentives, transaction costs, and emission reduction certainty.

Economic Incentives

Most previous economic studies that have sought to examine climate mitigation policy options have evaluated the impacts of GHG cap-and-trade systems. Under these analyses, a binding “cap” typically is placed upon total allowable GHG emissions. This cap creates a “scarcity

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into the atmosphere has the same climate forcing as 21 tons of CO_2. (IPCC, 1996)

12 US EPA, 2001(a).

13 See for example Bailie, et.al, 2001 and Reilly, et.al., 1999 and 2000.

value" for GHG emissions and, in turn, a price for marketable GHG emission allowances. Faced with an allowance price, individual sources make decisions about whether to reduce emissions at their own facilities or buy emissions allowances from other sources. Each source would have an incentive to control emissions up to the point where its marginal costs of doing so equals the cost of purchasing another source's allowances, i.e., the allowance price.

As allowance prices rise, sources will have an increasing incentive to reduce emissions. At a global allowance price of one dollar per metric ton of carbon, EPA estimates that a global cap-and-trade program (including all greenhouse gases) would result in GHG reductions of approximately 265 MMTCE in 2010 and 300 MMTCE in 2020. Figure 20 and Figure 21 depict the U.S. and international marginal GHG abatement costs used to obtain these results.[14] (See the Appendix for a description of the analytical tools used for this analysis and coverage of source categories.)

A number of factors influence the types of emission reductions and costs of a GHG offset program compared to a GHG cap-and-trade program confined to one or more regulated sectors. In an offset program, only a fraction of sources (those within the sector(s) subject to a cap) would see a direct and immediate economic incentive to participate – an allowance price. In the case examined here, the electricity sector must offset emissions above 2008 emissions levels and therefore must seek to reduce its own emissions or purchase offsets from other sources.

The other GHG emitting sectors, however, see a more limited economic incentive to participate since they are not subject to a mandatory emissions target. While these sectors can potentially achieve economic advantage by generating and selling offsets, this incentive may not be as strong as if all sources were subject to an emissions cap. Consequently, sources in sectors outside of the electricity sector may not participate as actively as if they had to limit their own emissions. This implies that the sources outside the cap might expend less effort to achieve emissions reductions, thus creating fewer abatement opportunities.

Transaction Costs

Transaction costs are an additional factor influencing the costs of an offset program. Transaction costs include "deal making" activities and programmatic compliance activities undertaken by firms. Specifically, these costs may include project development costs, decision-making costs internal to firms, search costs, negotiation and brokerage costs, monitoring and verification (including certification and registration) costs, and insurance costs.

Estimating the transaction costs that would apply to offsets purchased in cases analyzed here proves difficult, as there have been relatively few comparable programs (at least for GHG offsets). A literature review of project experience and modeling assumptions, as well as personal communication with various project development professionals, researchers, and other experts,

14 Estimates of non-CO_2 marginal abatement curves represent about 35% of global non-CO_2 GHG emissions available for offsets. The forest carbon sequestration supply curves for the countries covered in the analysis represent only about 35% of the global forest area (including natural forests and plantations).

suggests a range of transaction cost estimates from $0.04/ton of carbon to well over $10/ton.[15] However, most of the high estimates have little or no documentation to support them. The same literature suggests that transaction costs as a percentage of total GHG abatement cost (for the GHG pilot projects and GHG trades undertaken so far) have ranged from under 5 percent to over 75 percent. Further, evidence from established non-climate projects at the Global Environmental Facility (e.g., stratospheric ozone layer protection projects) indicates that moderate program experience reduces transaction costs from roughly 30 percent to under 10 percent of total costs.[16]

15 See, variously: Ashford, 2001; Bailie et al., 2001; EPRI, 2000; Free, 2001; ICF, 1998; Ghersi, 2001; Heister, 2001; Hourcade and Ghersi, 2001; Kurosawa, 2001; Mascarella, 2001; Mathur, 2001; Powell et al., 1997; Shifflet, 2001; UNFCCC, 2001; World Bank PCF, 2000; Youngman, 2001.

16 Mathur, 2001.

Figure 20. U.S. GHG Abatement Costs in 2010

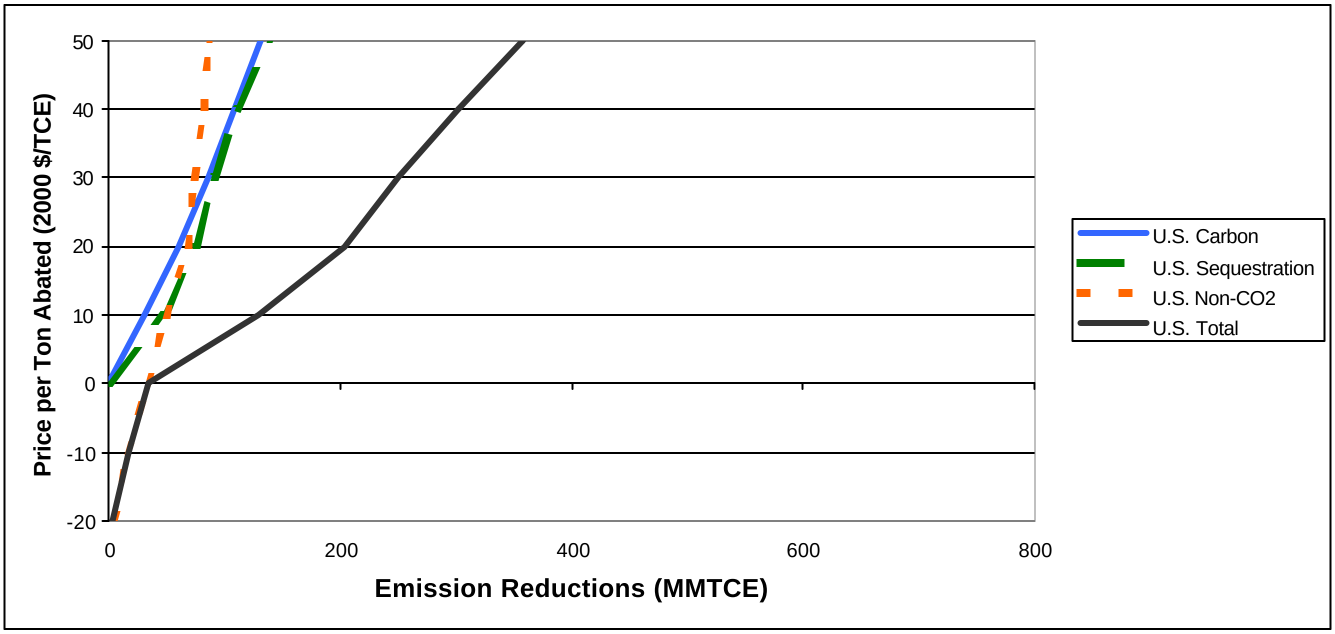
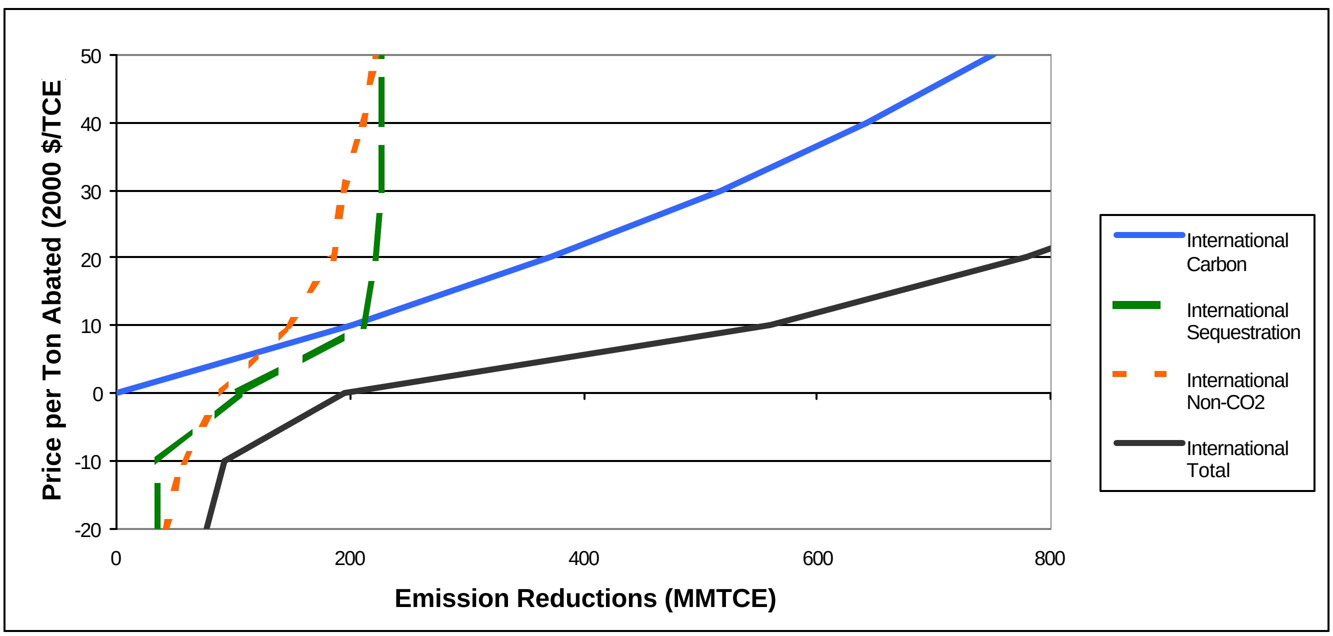


Figure 21. International (Non-U.S.) GHG Abatement Costs in 2010



EPA's experience with the well established SO_2 trading program, where government approval of trades is not necessary, reflects transaction costs of one to two percent of allowance prices.[17] However, the SO_2 trading program is a streamlined allowance-based cap-and-trade program that does not include offsets from outside the electricity sector. Therefore, it does not require case-by-case review of trades. In contrast, the inclusion of offsets and the case-by-case documentation and review that this necessitates would be expected to increase the transaction costs associated with the GHG offset program.

Finally, a detailed and current engineering cost analysis prepared on GHG-offset transaction costs predicts roughly $1/ton carbon for typical coal mine methane recovery projects.[18] Of the literature reviewed, this study appears to be the best-documented estimate of GHG transaction costs. However, given the overall uncertainties discussed above, EPA is not prepared to predict transaction costs for the GHG offset program at this time.

Emissions Reduction Certainty

A major distinction between a GHG cap-and-trade and a GHG offset program is the ability to verify that emissions are actually reduced in the offset producing sectors that are not subject to a cap on emissions. As long as aggregate emissions under a GHG program are monitored and verified and compliance is enforced, the emission reduction goals will be achieved. In the case of the electricity sector, such calculations are relatively straightforward since sources are already equipped with continuous emissions monitoring systems that measure several emissions, including CO_2.

However, for an offset program covering other sectors of the economy, it becomes difficult to construct a verification system that ensures emissions reduction certainty for specific projects. Verification systems designed to ensure emissions reduction certainty for sector-specific offset programs confront many challenges, two of which are "additionality" and "leakage."

Judgements about additionality involve determining whether actions that are candidates for earning offsets would have occurred in the absence of an offset program. There are numerous reasons why a firm's emissions could decrease regardless of whether an offset project is completed. For example, factors such as reduced production, compliance with other policies, or changing market conditions could result in emission reductions. In cases where a program awards offsets for reductions that would have happened in the absence of the program, overall emissions could increase. The offsets created by projects that are not "additional" are said to be "anyway" tons, i.e., reductions that would have occurred anyway.

"Leakage," which may increase overall emissions, is another potential problem in an offset program. Because offset programs do not cover the entire universe of sources within a source category, an apparent reduction at one source could precipitate an increase in emissions at another. If offsets are awarded for leaked emissions, then net emissions do not decrease as a result of the project producing carbon offset credits and may actually increase. For example, a

17 ICF, 1998.

18 Free, 2001.

conservation project in one forest may lead to increased harvesting elsewhere. The "leakage" from one forest to the other effectively nullifies the GHG emissions reductions of the conservation project and, if offset credit is awarded, allows a capped source to increase its emissions. While methods are available to screen for additionality and leakage, they remain imperfect. Increasing rigor in the screening and enforcement process also contributes to increasing transaction costs.

Adjustment of Available Emissions Offsets

To estimate the emissions reductions and costs of an electricity CO_2 offset program, EPA has constructed three cases that could account for the inherent differences between offset and trading programs (including transaction costs and other factors such as leakage and additionality). Each case is based on the relationship between the cost and availability of abatement opportunities across all sectors both domestically and internationally. The three cases are described below.

Case I: In this case, EPA assumes the offset program sends a strong economic signal for emission reductions to sources outside the electricity sector and all reductions are real and verifiable. In other words, the offset program is assumed as effective as a cap-and-trade program. Institutional or informational barriers at the domestic and international level are not significant. Any potential limitations on program effectiveness such as "anyway" tons and "leakage" are effectively and inexpensively removed from the system. Case I represents the ideal offsets program.

Case II: In this case, EPA assumes that abatement opportunities are limited because the offset program provides weaker incentives for emissions reductions outside the electricity sector (relative to economy-wide cap-and-trade). In addition, institutional barriers may exist that limit GHG abatement opportunities. International reductions are affected more than domestic reductions because greater institutional barriers may exist in securing international offsets, such as potentially different approval procedures established by foreign governments. EPA assumes in this case that GHG abatement opportunities can be successfully screened to ensure that reductions are not "anyway" tons or leaked emissions. As a proxy to estimate these effects, EPA reduced the domestic availability of emissions offsets by 50 percent and reduced the international availability of offsets by 75 percent, as compared to Case I.

Case III: In this case, the program monitoring and verification has difficulty distinguishing between projects in which emission reductions resulted from the offset program and projects characterized by "anyway" tons and leakage effects. Therefore, emissions reductions certainty cannot be guaranteed. While this would increase the quantity of available offsets, the existence of "anyway" tons and leakage in the system undermine the GHG emissions reductions goal. As a proxy to estimate this, EPA increased the quantity of offsets available from all sources by 20 percent, as compared to Case I.

3.3. Results

EPA analyzed the impacts of requiring the U.S. electricity sector to offset CO_2 emissions by emissions reductions or sinks from other sources starting in 2008. This analysis is conducted with the U.S. electricity sector CO_2 emissions baseline scenarios listed in section 3.1. The first scenario uses the IPM® Base Case. The second uses EIA's electricity sector CO_2 emissions forecast.

The analysis is presented in the context of different possible interactions with the rest of the world. The first assumes that there is no demand for CO_2 offsets other than from the U.S. The second assumes that the Kyoto Protocol is implemented by the signatories of the Bonn Accord and that currently available GHG emissions projections can be used to estimate the resulting emissions market. The third analysis examines the impacts of different possible outcomes of the Kyoto Protocol.

3.3.1. U.S. Electricity Sector is the Only Source of Demand for Offsets

Table 2 shows that the price of allowances in all cases is equal to the transaction costs if there is no demand for offsets other than from the U.S. Total abatement costs, which represent the resource costs associated with securing GHG emissions reductions, are negligible. Transactions costs, and government program costs, are uncertain due the lack of previous experience with GHG offset programs and are not reported below. Further, while the resource costs of generating GHG offsets may be negligible, electricity generators may face expenses in the purchase of offsets. Therefore, individual electric utility costs may be positive. As a result of such low abatement costs, the fuel mix in the electricity sector is not likely to be affected by the options examined. Although the other two three-pollutant scenarios (1 and 3) were not used as alternative base cases in this analysis, EPA expects that the results would be similar to those resulting from Scenario 2.

Table 2.a. Allowance Prices of Greenhouse Gas Offsets in 2010 (2000 $/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	transactions cost	transactions cost	transactions cost
IPM®	transactions cost	transactions cost	transactions cost

Table 2.b. Total Abatement Costs in 2010 ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	negligible	negligible	negligible
IPM®	negligible	negligible	negligible

Table 2.c. Allowance Prices of Greenhouse Gas Offsets in 2020 (2000$/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	transactions cost	transactions cost	transactions cost
IPM®	transactions cost	transactions cost	transactions cost

Table 2.d. Total Abatement Costs in 2020 ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	negligible	negligible	negligible
IPM®	negligible	negligible	negligible

While the price of allowances is generally sensitive to the global availability of offsets, the modest CO_2 reductions required by the Senators' request imply that allowance prices are likely to equal transactions costs for a wide range of offsets availability. In the case where six MMTCE are required in 2010 (IPM Base Case), the price rises above transaction costs only if fewer than three percent of worldwide offsets were available. Likewise, in 2020 (where the number of required offsets is 58 MMTCE), the allowance price rises above transaction costs only if availability of worldwide offsets falls below 24 percent. For example, in 2020, if only 20% of worldwide offsets were available, the allowance price would be one dollar, plus transactions costs.

Total abatement costs are negligible for all cases and may even result in net economic benefits. Low or negative costs are possible because the offset program may provide sufficient incentives to efficiency or other mitigation projects (e.g., methane recovery) that may result in long-term economic benefits. Ancillary benefits such as the reduction of conventional pollutants from a CO_2 offset program may result, but are not quantified.

The abatement costs of the program are low due to two principal factors. First, the size of the overall GHG reduction called for in the Senators' request is relatively modest: the Senators' requested that EPA analyze a program that offsets the growth in GHG emissions in only one sector of the U.S. economy—the electricity sector—and offsets are not required until after 2008. By 2010, the required level of offsets represents less than one percent of U.S. electricity sector CO_2 emissions, and approximately nine percent by 2020. Secondly, there is an abundance of offset opportunities due to the Senator's specification that verifiable GHG reductions or sinks from any source achieved in any nation would be available to satisfy the offset requirement. If the offset requirement were greater, or if the opportunities for obtaining offsets were limited, abatement costs and allowance prices would be higher.

3.3.2. Interaction with the Kyoto Process

EPA has analyzed how the U.S. policy of offsetting CO_2 emissions in the U.S. electricity sector could be affected by interactions with implementation of the Kyoto Protocol. The recent agreement on the Kyoto Protocol negotiated in Bonn, if ratified, would require developed country signatories to reduce their GHG emissions to approximately 4.2% below their 1990 emissions levels by 2008-2012.[19] The Kyoto Protocol allows for GHG emissions trading among developed country signatories, the availability of offsets in developing countries, and country-specific credit for terrestrial sequestration. (See Appendix A.4. for a description of the Kyoto Agreement). These countries currently have no commitments after 2012, but EPA has assumed for this analysis that subsequent agreements maintain the emissions targets through 2020.

This analysis uses CO_2 emissions projections from EIA and non-CO_2 emissions projections developed by EPA.[20] The total number of emission reductions required by the Kyoto Protocol is highly dependent upon emissions in the Former Soviet Union and Eastern Europe, which have declined since 1990. Factoring in all GHG emissions and the credits allowed for sequestration, there is no apparent need for reductions or offsets in 2010 as a result of the Protocol, but roughly 280 MMTCE of offsets may be required by 2020.

Adding the Kyoto reductions to the demand to offset U.S. electricity sector CO_2 emissions after 2008, the world demand for offsets in 2020 is approximately 340-355 MMTCE. Three cases, similar to the different assumptions of program effectiveness used previously, are examined.[21] For these cases, the allowance price ranges from $1-9 (plus transactions costs). The total abatement costs for the U.S. would range from negligible to $190 million.

19 For certain high GWP gases, countries may use their emissions from 1990 or 1995 as their baseline. The figure of 4.2% for the total reduction is determined from country-specific 1990 and 1995 emissions by GHG, and calculating the respective target emission levels specified in the Kyoto Protocol.

20 Energy Information Administration, "International Energy Outlook 2001." March 2001. DOE/EIA-0484(2001).

21 These cases are modified from Cases I-III since developed countries are assumed to engage in emissions trading.

Table 3.a. Allowance Prices of Greenhouse Gas Offsets in 2010 (2000 $/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	transactions cost	transactions cost	transactions cost
IPM®	transactions cost	transactions cost	transactions cost

Table 3.b. Total Abatement Costs in 2010 ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	negligible	negligible	negligible
IPM®	negligible	negligible	negligible

Table 3.c. Allowance Prices of Greenhouse Gas Offsets in 2020 with Kyoto Protocol (2000$/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	2 + transactions cost	9 + transactions cost	1 + transactions cost
IPM®	2 + transactions cost	8 + transactions cost	1 + transactions cost

Table 3.d. Total Abatement Costs in 2020 with Kyoto Protocol ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	negligible	190	negligible
IPM®	negligible	130	negligible

3.3.3 Alternative Emissions and Offsets Scenarios for Kyoto

The allowance price estimates above could be influenced by the availability of GHG allowances from the Former Soviet Union and Eastern Europe (FSU/EE). For example, emissions growth in the region could be higher or lower than predicted by the EIA emissions projections. Similarly, institutional constraints or government decisions may limit the availability of offsets from those countries. For example, one or more of the countries in the region may choose to bank some portion of their available offsets for their own future use, rather than sell them on the international market.

If the available offsets in FSU/EE were half that predicted by EIA emissions forecasts (roughly 200 MMTCE fewer for both 2010 and 2020), CO_2 allowance prices could range from $4-17 (plus transactions costs) in 2020 and abatement costs could be between zero and $483 million. See Table 4 below. On the other hand, if emissions growth in FSU/EE slowed, so that available credits increased by 200 MMTCE, allowance prices would range from $0-2 (plus transaction costs).

Table 4.a. Allowance Prices of Greenhouse Gas Offsets in 2010 with Kyoto and 200 MMTCE Fewer Allowances Available (2000 $/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	transactions cost	5 + transactions cost	transactions cost
IPM®	transactions cost	6 + transactions cost	transactions cost

Table 4.b. Total Abatement Costs in 2010 with Kyoto and 200 MMTCE Fewer Allowances Available ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	negligible	negligible	negligible
IPM®	negligible	negligible	negligible

Table 4.c. Allowance Prices of Greenhouse Gas Offsets in 2020 with Kyoto and 200 MMTCE Fewer Allowances Available (2000$/TCE)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	6 + transactions cost	17 + transactions cost	4 + transactions cost
IPM®	5 + transactions cost	16 + transactions cost	4 + transactions cost

Table 4.d. Total Abatement Costs in 2020 with Kyoto and 200 MMTCE Fewer Allowances Available ($ million)

Global (All GHG and Sequestration)

Baseline	Case 1	Case 2	Case 3
EIA	46	483	negligible
IPM®	27	344	negligible

3.3.3. Banking

Senators Smith, Voinovich, and Brownback also requested that EPA consider the effect of banking CO_2 emissions allowances beginning in 2002. With banking, the electricity sector can secure allowances starting in 2002, six years before they are required to offset their emissions. There are two primary motivations for banking emissions allowances in this case. The first motivation is to avoid increased costs associated with the out-years of the program (i.e., the 2008-2020 period). Second, electricity generators may seek to hedge future emissions reduction obligations. Banking emissions allowances in earlier periods would act as an insurance policy against unanticipated events or future policy changes that may raise costs. Since, for the scenarios requested by the Senators, allowance prices are not anticipated to be high or increase significantly over the time frame of this analysis, there would seem to be little economic incentive to bank allowances. Thus, EPA did not model banking of CO_2 emissions allowances. However, electricity generators may prefer to achieve their offset obligations early for business planning purposes, likely resulting in lower costs later and reduced price volatility.

Appendix

For this analysis, EPA used several analytic tools to estimate the availability and potential cost of emissions reductions within and outside the electricity sector. This appendix describes the various models used by EPA in conducting both the three-pollutant and greenhouse gas analysis.

A.1. Three-Pollutant Analysis

Integrated Planning Model (IPM®)

Much of the analysis presented in this report is based on use of the Integrated Planning Model (IPM®), by ICF Resources, Inc. For this analysis, EPA populated the model with data from EIA, ICF, EPA and other public sources. IPM® is a detail-rich, bottom-up linear programming model of the electricity sector that finds the most efficient (i.e. least cost) approach to operating the electric power system over a given time period subject to specific constraints (e.g. pollution caps or transmission limitations). The model selects investment strategies given the cost and performance characteristics of available options, forecasts of customer demand for electricity, and reliability criteria. System dispatch, determining the proper and most efficient use of the existing and new resources available to utilities and their customers, is optimized given the resource mix, unit operating characteristics, and fuel and other costs. Unit and system operating constraints provide system-specific realism to the outputs of the model.

The IPM® is dynamic; it has the capability to use forecasts of future conditions, requirements, and option characteristics to make decisions for the present. This ability replicates, to the extent possible, the perspective of utility managers, regulatory personnel, and the public in reviewing important investment options for the utility industry and electricity consumers. Decisions are made based on minimizing the net present value of capital and operating costs over the full planning horizon.

Several factors make IPM® particularly well suited to model multi-emissions control programs. These include its ability to model complex interactions among the electric power, fuel, and environmental markets and a wide range of compliance options including:

1. Fuel switching (for example, switching from high sulfur to low sulfur coal),
2. Repowering (for example, repowering a coal plant to natural gas combined-cycle),
3. Pollution control retrofits (for example, installing a scrubber to control SO_2 emissions),
4. Economic retirement (for example, retiring an oil or gas steam plant), and
5. Dispatch adjustments (for example, running high-NO_x cyclone units less often, and low NO_x combined-cycle plants more often.)

IPM® also models a variety of environmental market mechanisms, such as emissions caps, allowances, trading, and banking. IPM's ability to capture the dynamics of the allowance market was particularly important for assessing the impact of the multi-emissions environmental policies evaluated in this report. EPA has recently completed a major update of the model's assumptions and computational structure. The analyses discussed in this report are products of the updated model. The following tables summarize many of IPM®'s key assumptions.

Table A.1.1. Key Assumptions in IPM 2000 EPA Base Case

Factor	Assumption
Electricity Demand Growth Rate (% per year, 2000-2020, net energy for load)	Before full accounting for CCAP: 1.8% (Based on AEO 2001) After full accounting for CCAP: 1.2 %
Climate Change Action Plan Reductions (billion kWh)	97.5 in 2000 468.1 in 2010 585.8 in 2015 733.0 in 2020
Planning Reserve Margins	Based on EIA and NERC Reports
Power Plant Lifetimes	Fossil units: none Nuclear: 10-year life extension option at age 30 20-year relicensing option at age 40
Fossil Capacity	Existing capacity as reported in NEEDS 1998, 1998 EIA 860a, 1998 EIA 860b, 1999 NERC ES&D and 1997 EIA 860. Includes both utility and independent power producer units.
Coal and Oil/Gas Steam Power Plant Annual Availability	Coal Steam: 85% Oil/Gas Steam: 85%
Power Plant Heat Rates	No change over time
Nuclear Capacity (GW)	2005: 88 2010: 82 2015: 77 2020: 73
Nuclear Capacity Factors (%)	2005: 85.3% 2010: 87.1% 2015: 88.2% 2020: 89.4%
Net Imports (billion kWh)	2005: 49.0 2010: 32.5 2015: 33.4 2020: 27.3
Hydroelectric Generation (billion kWh)	269 billion kWh annually, between 2005 and 2020
Renewables Generation (billion kWh)	34 billion kWh annually, between 2005 and 2020
Transmission Losses Between IPM Regions	2 percent
Transmission Capacity	Varies by region
Net Energy for Load (Electricity load assumptions in Billions of kWh)	2005: 3,925 2010: 4,120 2015: 4,366 2020: 4,574

Table A.1.2. Emissions Assumptions for Potential (New) Units in IPM 2000 EPA Base Case

Emission		Conventional Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Biomass Integrated Gasification Combined Cycle	Geothermal	Landfill Gas
SO_2	Assumed Controls	Scrubber	None	None	None	None	None	None	None
	Removal/ Emissions Rate	95% from sulfur content of coal	100%	None	None	None	0.08 lbs/MMBtu	None	100%
NO_x	Assumed Controls	SCR	SCR	SCR	None	None	None	None	None
	Emission Rate	0.05 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.10 lb/MMBtu	0.10 lb/MMBtu	0.02 lb/MMBtu	None	0.246 lb/MMBtu
CO_2	Assumed Controls	None	None	None	None	None	None	None	None
	Emission Rate	205.3 – 215.4 lb/MMBtu	205.3 – 215.4 lb/MMBtu	117.08 lb/mmBtu	117.08 lb/mmBtu	117.08 lb/mmBtu	No net emissions	None	No net emissions
Hg	Assumed Controls	Scrubber and SCR[1]	None	None	None	None	None	None	None
	Removal Rate	95%	100%	None	None	None	None	None	None
	Emission Rate	Varies with Hg content of Coal	None	0.00014 lbs/TBTu	0.00014 lbs/TBTu	0.00014 lbs/TBTu	0.57 lbs/TBtu	8 lbs/TBtu	0 lbs/TBtu

Note. All emissions are assumed to be zero for nuclear, advanced nuclear, wind, fuel cells, solar photovoltaic, and solar thermal.

EPA assumes 95% mercury removal for all coal types through a combination of FGD and SCR. EPA bases its removal on interpretation of Information Collection Request (ICR) data. See U.S. EPA, Performance and cost of mercury emission control technology applications on electric utility boilers. National Risk Management Research Laboratory, Office of Research and Development, September 2000. See also Fahlke, J. and A. Bursik, Impact of the state-of-the-art flue gas cleaning on mercury species emissions from coal-fired steam generators. Water, Air, Soil Poll., 80, 209-215. 1995.

Table A.1.3. Summary of Emission Control Performance Assumptions in IPM 2000 EPA Base Case

	SO_2 Scrubbers			NO_X Post-Combustion Controls				Mercury[1]	Other Controls	
	Limestone Forced Oxidation (LSFO)	Magnesium Enhanced Lime (MEL)	Lime Spray Dryer (LSD)	SCR[2]	SNCR	Gas Reburn: Low NO_x	Gas Reburn: High NO_x	Activated Carbon Injection	Combustion Optimization	Biomass Cofiring
Percent Removal	95%	96%	90%	90% (coal) 80% (gas) (Down to 0.05 lb/mmBtu)	35% (coal) 50% (gas)	40%	50%	80% (for routine scenarios)	0.5% heat rate (BTU/kwh) improvement 20% NOx reduction	--
Capacity Penalty[3]	2.1%	2.1%	2.1%	--	--	--	--	--	--	--
Fuel Use Impacts	--	--	--	--	--	16% gas use	16% gas use	--	--	<u>Cyclones</u> 5% Biomass, >200MW 15% Biomass, ≤ 200 MW <u>Other Coal</u> 2% Biomass, >200MW 15% Biomass, 200 MW
Cost (1999$)	See Table A.1.3.a			See Tables A.1.3.b and A.1.3.c				See Table A.1.3.d	\$250,000 capital cost \$40,000/yr FOM cost	--
Applicable Population	Coal boilers ≥ 100 MW	Coal boilers < 550 MW and ≥ 100 MW	Coal boilers ≥ 550 MW	Coal boilers ≥ 100 MW All oil/gas steam units.	All coal and oil/gas steam units	All oil/gas steam units	All oil/gas steam units	All coal units > 25 MW	Coal boilers ≥ 100 MW	All coal units

<u>Note</u>: Activated carbon injection, combustion optimization, and biomass cofiring are not implemented in IPM 2000 EPA Base Case, but are available capabilities that can be implemented, as applicable, in policy runs built on the Base Case. The capacity penalty implies that a plant's dispatchable capacity is reduced and its heat rate is increased by the percentage shown. EPA estimates that the operating penalties associated with scrubbers are between 0.7 - 2.0% of capacity. See U.S. EPA. <u>Controlling SO_2 emissions: a review of technologies</u>. USEPA, Washington, DC (EPA/600/R-00/093), November 2000); the 2.1% capacity penalty in the report, then, is conservative. The Agency estimates that the operating penalties associated with SCR are between 0.2 - 0.5%, largely due to equipment required to counter the pressure drop. See U.S. EPA. <u>Cost estimates for selected applications of NOx control technologies in stationary combustion boilers: responses to comments on the draft report</u>. USEPA, Washington, DC, June 1997. Because the operating penalties for SCR were small, they were not included in the modeling.

EPA assumes 80% mercury removal for ACI. See ICF memo from K. Jayaraman, J. Haydel, and B.N. Venkatesh entitled <u>Mercury control cost calculations: assumptions, approach, and results</u>. September 2000. Specifically, see the attachment entitled <u>Mercury control technology assumptions determined during EPA's meeting with DOE at EPA</u>, Washington, DC, August 22-23, 2000.

Table A.1.3.a. Scrubber Costs for Representative MW and Heat Rates (1999$)

Scrubber Type	MW	Heat Rate 9,000	Heat Rate 10,000	Heat Rate 11,000	Cost
LSFO	100	514	528	541	Capital Cost ($/kW)
Minimum Cutoff: >= 100 MW		18	18	18	Fixed O&M ($/kW-yr)
Maximum Cutoff: None		1	1	2	Variable O&M (mills/kWh)
	300	252	262	272	Capital Cost ($/kW)
		10	10	11	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	500	193	201	209	Capital Cost ($/kW)
		8	8	9	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	700	159	166	173	Capital Cost ($/kW)
		7	7	7	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	1,000	176	186	194	Capital Cost ($/kW)
		7	7	7	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
MEL	100	352	364	375	Capital Cost ($/kW)
Minimum Cutoff: >= 100 MW		15	16	16	Fixed O&M ($/kW-yr)
Maximum Cutoff: < 500 MW		1	1	1	Variable O&M (mills/kWh)
	200	232	242	251	Capital Cost ($/kW)
		11	11	12	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	300	233	244	255	Capital Cost ($/kW)
		10	11	11	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	400	207	218	229	Capital Cost ($/kW)
		9	9	10	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
	500	185	195	204	Capital Cost ($/kW)
		8	9	9	Fixed O&M ($/kW-yr)
		1	1	1	Variable O&M (mills/kWh)
LSD	600	148	156	163	Capital Cost ($/kW)
Minimum Cutoff: >= 550 MW		5	5	5	Fixed O&M ($/kW-yr)
Maximum Cutoff: None		2	2	2	Variable O&M (mills/kWh)
	700	137	145	152	Capital Cost ($/kW)
		5	5	5	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	800	134	140	146	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	900	135	142	149	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)
	1,000	128	135	141	Capital Cost ($/kW)
		4	4	4	Fixed O&M ($/kW-yr)
		2	2	2	Variable O&M (mills/kWh)

Table A.1.3.b. Costs of Post-Combustion NO_x Controls for Coal Plants (1999 $)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Gas Use	Percent Removal
SCR[2]	$80	$0.53	0.37	--	90%[1]
SNCR[3] (Low NO_x Rate)	$17.1	$0.25	0.84	--	35%
SNCR[4] (High NO_x Rate—Cyclone)	$9.9	$0.14	1.31	--	35%
SNCR[5] (High NO_x Rate—Other)	$19.5	$0.30	0.90	--	35%
Natural Gas Reburn[6] (Low NO_x)	$33.3	$0.50	--	16%	40%
Natural Gas Reburn[6] (High NO_x)	$33.3	$0.50	--	16%	50%

Notes: Low NO_x is < 0.5 lbs/mmBtu. High NO_X is ≥ 0.5 lbs/mmBtu.

1. Cannot provide reductions beyond 0.05 lbs/mmBtu.

2. SCR Cost Scaling Factor:
SCR Capital and Fixed O&M Costs: $(242.72/MW)^{0.35}$.
For Variable O&M, multiply the VOM value shown in the table by the previous scaling factor. Then, add the constant 0.603212 to the resulting product.
Scaling factor applies up to 500 MW.

3. Low NO_x SNCR Cost Scaling Factor:
Low NO_x Coal SNCR Capital and Fixed O&M Costs: $(200/MW)^{0.577}$.
Scaling factor applies up to 500 MW.

4. High NO_x SNCR—Cyclone Cost Scaling Factor:
High NO_x Coal SNCR—Cyclone Capital and Fixed O&M Costs: $(100/MW)^{0.577}$
VO&M = 1.27 for MW $\leq$ 300,
VO&M = 1.27 – ((MW – 300)/100) * 0.015 for MW > 300.

5. High NO_x Coal SNCR—Other Cost Scaling Factor:
High NO_x Coal SNCR—Other Capital and Fixed O&M Costs: $(100/MW)^{0.681}$
VO&M = 0.88 for MW $\leq$ 480,
VO&M = 0.89 for MW > 480.

6. Gas Reburn includes $5.2/kW charge for pipeline.

Table A.1.3.c. Cost of Post-Combustion NO_x Controls for Oil/Gas Steam Units (1999 $)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Removal
SCR[1]	28.9	0.89	0.10	80%
SNCR[2]	9.7	0.15	0.45	50%
Gas Reburn[1]	20.3	0.31	0.03	50%

Notes:

1. SCR and Gas Reburn Cost Scaling Factor:
SCR and Gas Reburn Capital Cost and fixed O&M: (200/MW)0.35
Scaling factor applies up to 500 MW

2. SNCR Cost Scaling Factor:
SNCR Capital Cost and fixed O&M: (200/MW) 0.577
Scaling factor applies up to 500 MW

Table A.1.3.d. Cost Components for 80% Mercury Removal Using ACI of Representative 500 MW, 10,000 Btu/kWh Heat Rate Units for Various Control Configurations and Coal Types

Coal Type	Existing Pollution Control Technology	Sulfur Grade	Capital Cost (1999$/kW)	FOM (1999$/kW/yr)	VOM (1999mills/kWh)	Removal Efficiency (%)
Bituminous	ESP	L	13.48	2.21	0.61	80
	ESP/O	L	13.48	2.21	0.61	80
	ESP+FF	L	12.50	2.09	0.37	80
	ESP+FGD	H	3.63	1.03	0.69	80
	ESP+FGD+SCR	H	ACI not applicable			
	ESP+SCR	L	13.48	2.21	0.61	80
	FF	L	13.48	2.21	0.61	80
	FF+DS	H	2.34	0.87	0.36	80
	FF+FGD	H	3.63	1.03	0.69	80
	HESP	L	3.63	1.03	0.69	80
	HESP+FGD	H	52.03	6.85	0.31	80
	HESP+SCR	L	47.00	6.39	0.43	80
	PMSCRUB+FGD	H	3.63	1.03	0.69	80
	PMSCRUB+FGD+SCR	H	ACI not applicable			
Bituminous	ESP	H	10.93	1.91	3.54	80
	ESP/O	H	10.93	1.91	3.54	80
	ESP+FF	H	6.56	1.38	1.66	80
	ESP+FGD	L	11.03	1.92	0.11	80
	ESP+FGD+SCR	L	ACI not applicable			
	ESP+SCR	H	10.93	1.91	3.54	80
	FF	H	10.93	1.91	3.54	80
	FF+DS	L	2.34	0.87	0.36	80
	FF+FGD	L	12.98	2.15	0.48	80
	HESP	H	55.70	1.38	1.75	80
	HESP+FGD	L	45.28	6.17	0.13	80
	HESP+SCR	H	55.70	7.45	1.75	80
	PMSCRUB+FGD	L	11.03	1.92	0.11	80
	PMSCRUB+FGD+SCR	L	ACI not applicable			
Lignite	ESP	L	16.28	2.61	1.24	80
	ESP+FF	L	12.09	2.05	0.16	80
	ESP+FGD	L	14.99	2.39	0.83	80
	FF+DS	L	1.05	0.72	0.11	80
	FF+FGD	L	11.34	1.96	0.07	80
Subbituminous	ESP	L	16.28	2.61	1.24	80
	ESP+DS	L	13.47	2.21	0.93	80
	ESP+FGD	L	12.40	2.08	0.62	80
	ESP+SCR	L	13.47	2.21	0.93	80
	FF	L	10.01	1.80	0.12	80
	FF+DS	L	0.87	0.70	0.08	80
	FF+FGD	L	9.39	1.72	0.05	80
	HESP	L	54.44	7.30	0.13	80
	HESP+FGD	L	54.33	7.28	0.13	80
	HESP+SCR	L	54.44	7.30	0.13	80
	PMSCRUB	L	13.47	2.21	0.93	80
	PMSCRUB+FGD	L	12.40	2.08	0.62	80

Table A.1.4. Performance and Unit Cost (1999$) Assumptions for Potential (New) Capacity from Fossil/Nuclear Technologies in IPM 2000 Base Case

	Conventional Pulverized Coal	Integrated Gasification Combined Cycle	Combined Cycle	Advanced Combustion Turbine	Combustion Turbine	Advanced Nuclear
Size (MW)	400	428	400	120	160	600
Lead Time (years)	4	4	3	2	2	4
Availability	85%	87.7%	90.4%	92.3%	92.3%	90.7%
Assumed emission controls	Scrubber, SCR	SCR	SCR	None	None	None
Vintage #1 (years covered)	2005-2009	2005-2009	2005-2009	2005-2009	2005-2009	2005-2009
Vintage #2 (years covered)	2010 & after	2010 & after	2010 & after	2010 & after	2010 & after	2010-2014
Vintage #3 (years covered)	N/A	N/A	N/A	N/A	N/A	2015 & after
Vintage #1						
Heat Rate (Btu/kWh)	9,253	7,469	6,562	8,567	11,033	10,400
Capital ($/kW)	1,321	1,427	590	438	388	2,465
Fixed O&M ($/kW/yr)	20.08	32.12	12.74	8.93	6.08	50.97
Variable O&M ($/MWh)	3.87	1.10	1.10	1.00	1.00	2.03
Vintage #2						
Heat Rate (Btu/kWh)	9,087	6,968	6,350	8,000	10,600	10,400
Capital ($/kW)	1,305	1,393	563	394	348	2,402
Fixed O&M ($/kW/yr)	20.08	32.12	12.74	8.93	6.08	50.97
Variable O&M ($/MWh)	3.87	1.10	1.10	1.00	1.00	2.03
Vintage #3						
Heat Rate (Btu/kWh)	--	--	--	--	--	10,400
Capital ($/kW)	--	--	--	--	--	2,276
Fixed O&M ($/kW/yr)	--	--	--	--	--	50.97
Variable O&M ($/MWh)	--	--	--	--	--	2.03

Note: The capital cost includes both the overnight capital charge rate and the interest during construction.

Table A.1.5. Performance and Unit Cost Assumptions for Potential (New) Capacity from Renewable and Non-Traditional Technologies in IPM 2000 EPA Base Case

	Biomass Gasification Combined Cycle	Wind	Fuel Cells	Solar Photovoltaic	Solar Thermal	Geothermal	Landfill Gas
Size (MW)	100	50	10	5	100	100	100
First Year Available	2010	2005	2005	2005	2005	2005	2005
Lead Time (years)	4	3	2	2	3	4	1
Availability	87.7%	90%	90%	90%	90%	87%	85%
Generation capability	Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile	Economic Dispatch	Economic Dispatch
Assumed emission controls	--	--	--	--	--	--	--
Vintage #1 (years covered)	2010-2030	2005-2030	2005-2014	2005-2030	2005-2030	2005-2030	2005-2030
Vintage #2 (years covered)	--	--	2015-2030	--	--	--	--
Vintage #1							
Heat Rate (Btu/kWh)	8,219	0	5,574	0	0	32,391	10,000
Capital ($/kW)	1,490	1,031-2,625[1]	2,175	2,576	3,187	1,846-6,174[2]	1,299
Fixed O&M ($/kW/yr)	44.81	26.41	15.00	9.97	47.40	62.40-210.50[2]	78.58
Variable O&M ($/MWh)	5.34	0.00	2.06	0.00	0.00	0.00	10.48
Vintage #2							
Heat Rate (Btu/kWh)	--	--	5,361	--	--	--	--
Capital ($/kW)	--	--	1,566	--	--	--	--
Fixed O&M ($/kW/yr)	--	--	15.00	--	--	--	--
Variable O&M ($/MWh)	--	--	2.06	--	--	--	--

Notes:

1. Capital costs for wind plants vary by wind class and cost class.
2. Capital and fixed O&M costs for geothermal plants are site specific.

Table A.1.6. Capital Charge Rates and Discount Rates by Plant Type in IPM 2000 EPA Base Case

Investment Technology	Capital Charge Rate	Discount Rate	Financing Structure
Environmental Retrofits	12.0%	5.34%	Corporate
Nuclear Retrofits (age 30+10 yrs)	19.0%	5.34%	Corporate
Nuclear Retrofits (age 40+20 yrs)	13.3%	5.34%	Corporate
Repowering of Existing Units	12.9%	6.14%	Project
Coal	12.9%	6.14%	Project
Combined Cycle	12.9%	6.14%	Project
Combustion Turbine	13.4%	6.74%	Project
Renewable Generation Technologies	13.4%	6.74%	Project

Note: The book life of the two nuclear retrofit options is 10 and 20 years, respectively. All the remaining technologies assume a 30-year book life.

A.2. Greenhouse Gas Analysis

While IPM® is a detailed electricity sector model, it cannot assess all GHG emissions and mitigation opportunities. To develop a more complete picture of GHG emissions and abatement opportunities, a number of other modeling tools have been utilized. These tools evaluate GHG abatement opportunities in various sectors both domestically and internationally. This analysis incorporates the results of the Second Generation Model (SGM), forestry and agricultural models such as the Forestry and Agriculture Optimization Model (FASOM) and analyses of non-CO_2 GHG emissions and abatement opportunities.

EPA uses emissions reductions and cost data from these models to analyze the total potential for GHG emission reductions or sequestration achievable and at what cost.[22] While the availability and costs of emissions reductions varies across source categories, this relationship has been estimated as a broad aggregate for this exercise.

A.2.1. Second Generation Model

DOE's Pacific Northwest National Laboratory's Second Generation Model (SGM) is a 13-region, 24-sector computable general equilibrium (CGE) model of the world that can be used to estimate the domestic, and international, economic impact of policies designed to reduce GHG emissions. Numerous economic analyses have been conducted using the SGM framework both inside and outside of the government.[23]

The SGM is a dynamic recursive model. Recursive models are a sequence of static models with rules for determining the amount of savings and therefore the total amount of new capital constructed in each time period. SGM uses expectations of future prices to determine savings and investment. Within the energy sector in SGM, energy-using equipment is "vintaged" to account for capital turnover and therefore can examine the response of the economy over time to policy changes.

The SGM is designed specifically to address global climate change issues, with special emphasis on the following types of analysis:

1. projecting baseline GHG emissions over time for a single country, a group of countries, or the world;

2. finding the least-cost way to meet any particular GHG emissions reduction target;

3. providing a measure of the carbon price, in dollars per metric ton; and

4. providing a measure of the overall cost of meeting an emissions target.

22 Emission reductions already required by law are accounted for in the baseline emission projections. Potential emission reductions from voluntary partnership programs are not included in the baseline and therefore are reflected in future abatement opportunities and the calculation of future abatement costs.

23 Sands et al., 1999.

For this analysis, EPA used the SGM to obtain estimates of marginal abatement costs for both the U.S. and international energy sectors (CO_2 abatement opportunities from all energy-using sources). The abatement cost curves are built up from a series of model runs, each of which sets the carbon price at a fixed level and holds it there for the duration of the run. Abatement costs are constructed using carbon prices every ten dollars up to fifty dollars.

Outside of the U.S. electricity sector, CO_2 offset opportunities exist in the domestic industrial and transportation sectors, which represent about 60 percent of U.S. energy-related CO_2 emissions.[24] Industrial energy efficiency projects, fuel switching in industrial boilers, and emissions improvements in vehicle fleets are examples of possible offset candidates.

Similarly, under the offset scenarios outlined in the letter, the U.S. electricity sector also may pursue reductions internationally. Given the level of economic growth and associated increase in CO_2 emissions that is predicted in the developing world, the energy sectors in these countries are anticipated to be a source of inexpensive and abundant offsets. For example, China's energy and home heating systems are largely dependent on coal. Projects that help shift China away from coal and towards natural gas, biomass, wind, and other renewables could generate large quantities of offsets at relatively low cost. Similar opportunities exist in India, Brazil, South Korea, and the rest of the developing world.

A.2.2. Agricultural and Forestry Models

The models used for the U.S. forestry and agriculture sectors include the Forestry and Agriculture Optimization Model (FASOM) and the Agricultural Sector Model + Greenhouse Gases (ASMGHG).[25] These models are based on mathematical programming, price endogenous representations of the forestry and agricultural sectors, modified to include carbon sequestration and GHG emission accounting. For example, ASMGHG depicts production, consumption, and international trade in 63 U.S. regions of 22 traditional and three biofuel crops, 29 animal products, and more than 60 processed agricultural products. FASOM includes carbon production from forests in the U.S. using data on land diversion, carbon production, and the economic value of forest products. The data from these models are 30-year average results over the 2000-2029 period.

The international forestry sequestration offsets analysis is based upon a computational model, Comprehensive Mitigation Assessment Process (COMAP), which estimates "bottom-up" engineering cost curves for seven key tropical forestry countries—Brazil, China, India, Indonesia, Mexico, the Philippines and Tanzania—representing about two-thirds of the tropical forest area in the world. The COMAP model has been developed under the auspices of the F7 Tropical Forestry Climate Change Research Network coordinated by the Lawrence Berkeley National Laboratory (LBNL) and EPA since 1993. COMAP is a spreadsheet model that runs from 1990-2100 or as specified, at the national scale, and produces changes in biomass, carbon,

24 USEPA, 2001(a).

25 FASOM was developed by the U.S. Forest Service and Dr. Bruce McCarl. ASMGHG was developed by Bruce McCarl.

and the net present value for specified forest management practices, forest types, and sub-regions within countries.

Terrestrial carbon sequestration involves the absorption of atmospheric CO_2 and subsequent storage by trees, plants, and soils. In 1999, terrestrial systems sequestered approximately 270 MMTCE in the U.S. and 1,600 MMTCE worldwide. Below are brief descriptions of sequestration processes and potential options that were included in this offsets analysis. However, coverage of forest and agricultural sequestration opportunities in these models is incomplete. Thus, abatement opportunities may be greater and costs lower than predicted in this analysis.

Forest Sequestration: As a result of biological processes in forests (e.g., growth and mortality) and anthropogenic activities (e.g., harvesting, thinning, and replanting), carbon is continuously cycled within forests ecosystems, as well as between the forest ecosystem and the atmosphere. As trees age, they continue to accumulate carbon until they reach maturity, at which point they are relatively constant carbon stores. Offsets from forest-based carbon sequestration can be stimulated by afforestation of agricultural lands, increasing the rotation length of tree planting cycles, or changing management intensity through improved silvicultural practices.

The forest carbon sequestration supply curves for the countries covered in the analysis represent about 35% of the global forest area (including natural forests and plantations). However, this figure understates the coverage of the analysis since a more accurate comparison would include the total global potential for forest carbon sequestration. Total global potential is difficult to estimate at present, but it is likely that if the total global sequestration potential were included in the analysis, the availability of CO_2 offsets would increase, and the allowance prices would decrease. The countries covered in the analysis include Brazil, Canada (partial), China, India, Indonesia, Mexico, Philippines, Tanzania, and the United States.

Agricultural Soil Sequestration: In 1999, soils absorbed approximately 71 MMTCE in the U.S. The amount of organic carbon contained in soils depends on the balance between inputs of organic matter and the loss of carbon through decomposition. Changing tillage systems from conventional tillage to minimum and no tillage, as well as reverting cropland back to grassland, generally increases soil carbon and could provide offsets.

A.3. Non-CO_2 GHG Analyses

Non-CO_2 GHG sources represent about 18 percent of total U.S. GHG emissions and about 32 percent of worldwide emissions.[26] Many technologies exist that can reduce emissions of these gases. In some cases, these technologies are already in use. These technologies may include recovery of methane emissions for energy, efficiency improvements, end-of-pipe controls (incineration), leak reduction, and chemical substitution, among others.

Estimates of non-CO_2 marginal abatement curves represent about 35% of global non-CO_2 GHG emissions. The countries and regions covered in the analysis include Australia, Brazil, Canada,

26 US EPA, 2001(a).

China, European Union, India, Japan, Mexico, Russia, Ukraine, United States, and New Zealand. Significant agricultural emissions from rice, livestock, and soils, especially in developing countries, are not modeled for this exercise give uncertainties regarding GHG abatement opportunities at this time. The estimates of potential offsets from non-CO_2 GHGs used in this analysis were derived from extensive bottom-up analyses of the technologies and management practices that reduce emissions. The sources examined include methane emissions from landfills, natural gas systems, and coal mines; HFC, PFC, and SF_6 emissions from various industrial sectors; and nitrous oxide emissions from adipic and nitric acid production. In each analysis, only currently available or close-to-commercial technologies are evaluated. EPA has assembled these emissions reductions and costs into marginal abatement curves showing the total emission reductions achievable at increasing monetary values of carbon, for the years 2010 and 2020.[27]

Two sources provide estimates for international offsets from other gases. First, the European Commission recently developed data for countries within the European Union.[28] Second, EPA has estimated offset costs in Australia, New Zealand, Brazil, Canada, China, India, Japan, Mexico, Russia, and Ukraine, based on available information on technologies and country-specific conditions. The discussion below broadly describes the sources that are included in the analysis.

Methane: Methane emissions are predicted to offer many low-cost offset opportunities. Landfills are the largest source of anthropogenic methane emissions in the U.S. Outside of the U.S., the largest source of recoverable methane is leakage from natural gas systems. Underground coal mines, livestock waste management, and a diverse group of other sources also provide potential offsets.

High GWP Gases: High GWP gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), which are important to an array of industrial technologies and consumer products.[29] The sources of high GWP emissions that are examined as carbon offsets in this analysis include HFCs from refrigeration and air conditioning; PFCs from semiconductor manufacturing and aluminum smelting; SF_6 from magnesium production, parts casting, and electric power distribution; HFC-23 from HCFC-22 production; and a diverse set of other source categories.

Nitrous Oxide: The main anthropogenic sources of nitrous oxide are agricultural soil management, fuel combustion in motor vehicles, and adipic and nitric acid production processes. However, marginal abatement cost estimates are only available for the adipic and nitric acid sources, which represent about 7 percent of total U.S. nitrous oxide emissions. Nitrous oxide emissions are a by-product in the production of adipic acid, which is used in the manufacture of synthetic fibers, coatings, and lubricants. Nitrous oxide is also a by-product of nitric acid

27 Emission reductions already required by law are accounted for in the baseline emission projections. Potential emission reductions from voluntary partnership programs are not included in the baseline and therefore are reflected in future abatement opportunities and the calculation of future abatement costs.

28 Commission of the European Union, 2000.

29 HFCs in particular have become important to the safe and cost-effective phase-out of chlorofluorocarbons (CFCs), halons, and other ozone-depleting chemicals worldwide.

production, which is used primarily to make synthetic commercial fertilizer and is a major component in the production of adipic acid and explosives. Opportunities exist to reduce nitrous oxides both in the U.S. and internationally.

A.4. The Greenhouse Gas Impacts of the Kyoto Protocol

Other countries reached agreement on the Kyoto Protocol at the meeting of the Conference of Parties at Bonn on July 23, 2001. If ratified, it would require countries in Western Europe, along with Canada, Japan, Australia, New Zealand, Russia and Eastern Europe to achieve greenhouse gas (GHG) emissions reductions of 4.2% below 1990 levels by the time frame of 2008-2012.[30] The Accord allows countries to trade GHG emissions reductions amongst themselves, and to offset their GHG emissions growth by reducing emissions in developing countries. Additionally, provisions have been made for these countries to receive country-specific credits for forestry and agricultural carbon sequestration activities. While there is no agreement on actions after 2012, this analysis assumes that the target of 4.2% below 1990 levels will be maintained through 2020.

Potential GHG Reductions

Calculating potential GHG reductions from the Kyoto Protocol requires estimates of "business as usual" for emissions of the six GHGs covered by the accord. EPA uses projections for the emissions of non-CO_2 greenhouse gases (methane, nitrous oxide, and high GWP gases) developed by EPA. Emissions projections for CO_2 are from the *International Energy Outlook 2001* prepared by the U.S. Department of Energy's Energy Information Administration (EIA).

Emissions Growth

For the countries of Western Europe, along with Australia, Canada, Japan, and New Zealand, CO_2 emissions in 2010 are projected by EIA to be 1,666 MMTCE, which represents growth of approximately 18 percent over 1990 emissions. These countries have proposed to achieve GHG emissions targets that are approximately 6.7% below their 1990 emissions levels. Factoring in EPA projections for non-CO_2 GHG emissions, these countries are projected to be 423 MMTCE above their agreed targets by 2010. By 2020, CO_2 emissions are projected to be 1800 MMTCE, and factoring in EPA estimates of non-CO_2 emissions, the countries' emissions are projected to be 551 MMTCE above their target in 2020.

Former Soviet Union and Eastern Europe

A principal uncertainty in estimating the impact of Kyoto Protocol is GHG emissions trends in the Former Soviet Union and Eastern Europe. With the collapse of the Soviet Union, economic activity in the region declined significantly. In the EIA projections, CO_2 emissions are projected to remain low, and when non-CO_2 emissions are factored in, total GHG emissions are projected to be below the regional target for by about 377 MMTCE in 2010. The difference in 2020 is projected to 222 MMTCE.

30 For certain high GWP gases, countries may choose their baseline to be their 1990 or 1995 emissions level.

Sequestration

The agreement reached at Bonn specifies the number of credits that each country may claim for forestry and agricultural carbon sequestration activities.[31] These credits roughly total 55 MMTCE per year.

Results

Total emissions reductions from the Kyoto Protocol are calculated by adding the negative emissions growth (some have called this "hot air") in the Former Soviet Union and Eastern Europe to the emissions growth from the other countries, and subtracting the specified sequestration credits. Using EIA projections for CO_2, the total GHG emissions reduction required by the Kyoto Protocol is fully offset by FSU and Eastern European "hot air" in 2010. Thus, the implementing countries may not be required to take additional abatement activity in 2010. However, by 2020, the total emission reduction from the Agreement is roughly 280 MMTCE. (See Tables A.4.1.a and A.4.1.b, below.)

Table A.4.1.a. 2010 Emissions Projections using EIA (MMTCE)

ALL GHG	1990	2010	Target	GAP	Sinks	Change from Baseline
FSU/EE	1,654	1,251	1,628	-377	23	-400
Europe/Ja/Can/ AUS/NZ	1,766	2,072	1,649	423	32	391
All Kyoto Protocol Countries	3,420	3,323	3,275	48	55	-9*

Table A.4.1.b. 2020 Emissions Projections using EIA (MMTCE)

ALL GHG	1990	2020	Target	GAP	Sinks	Change from Baseline
FSU/EE	1,654	1,405	1,628	-223	23	-246
Europe/Ja/Can/ AUS/NZ	1,766	2,206	1,649	557	32	525
All Kyoto Protocol Countries	3,420	3,611	3,275	336	55	281

* The –9 MMTCE reduction obtained using EIA CO_2 projections implies that no additional GHG abatement would be required.

Note: Columns may not add due to rounding errors and discrepancies in the source data.

31 See Appendix Z of the Report of the Conference of the Parties on the Second Part of its Sixth Session. (FCCC/CP/2001/5)

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